

GenOn Energy, Inc.
Form 10-Q
August 09, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2012

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number: 1-16455

GenOn Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware
(State or Other Jurisdiction of Incorporation
or Organization)

76-0655566
(I.R.S. Employer Identification No.)

**1000 Main Street,
Houston, Texas**
(Address of Principal Executive Offices)

77002
(Zip Code)

(832) 357-3000

(Registrant's Telephone Number, Including Area Code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its 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 registrant was required to submit and post such files). Yes No

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

Large Accelerated Filer

Accelerated Filer

Non-accelerated Filer
(Do not check if a smaller reporting company)

Smaller reporting company

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

As of August 2, 2012, there were 772,908,115 shares of the registrant's Common Stock, \$0.001 par value per share, outstanding.

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Glossary of Certain Defined Terms

ancillary services	services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include regulation service, reserves and voltage support.
Bankruptcy Court	United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division.
baseload generating units	units designed to satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously.
CAISO	California Independent System Operator.
capacity	amount of energy that could have been generated at continuous full-power operation during the period.
CenterPoint	CenterPoint Energy, Inc. and its subsidiaries, on and after August 31, 2002, and Reliant Energy, Incorporated and its subsidiaries, prior to August 31, 2002.
CFTC	U.S. Commodity Futures Trading Commission.
Clean Air Act	Federal Clean Air Act.
Clean Water Act	Federal Water Pollution Control Act.
CO ₂	carbon dioxide.
dark spread	the difference between power prices and the cost to generate electricity with coal.
deactivation	includes retirement, mothballing and long-term protective layup. In each instance, the deactivated unit cannot be currently called upon to generate electricity.
Dodd-Frank Act	the Dodd-Frank Wall Street Reform and Consumer Protection Act.
EBITDA	earnings before interest, taxes, depreciation and amortization.
EPA	United States Environmental Protection Agency.
EPC	engineering, procurement and construction.
EPS	earnings per share.
Exchange Act	Securities Exchange Act of 1934, as amended.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	United States generally accepted accounting principles.
GenOn	GenOn Energy, Inc. (formerly known as RRI Energy, Inc.) and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Mirant/RRI Merger.
GenOn Americas	GenOn Americas, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC.

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GenOn credit facilities	senior secured term loan and revolving credit facility of GenOn and certain of its subsidiaries.
GenOn Energy Holdings	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
GenOn Marsh Landing	GenOn Marsh Landing, LLC.
GenOn Mid-Atlantic	GenOn Mid-Atlantic, LLC and its subsidiaries, which include the baseload units at two generating facilities under operating leases.
GenOn North America	GenOn North America, LLC.
intermediate generating units	units designed to satisfy system requirements that are greater than baseload and less than peaking.
IRC	Internal Revenue Code of 1986, as amended.
IRC §	IRC section.
ISO	independent system operator.
ISO-NE	Independent System Operator-New England.
LIBOR	London InterBank Offered Rate.
long-term protective layup	a descriptive term for our plans with respect to the Shawville coal-fired units, including retiring the units from service in accordance with the PJM tariff, maintenance of the units in accordance with the lease requirements and continued payment of the lease rent. While the units are not decommissioned and reactivation remains a technical possibility, we do not expect to make any further investment in environmental controls for the units. Further, reactivation after the long-term protective layup would likely involve numerous new permits and substantial additional investment.
MADEP	Massachusetts Department of Environmental Protection.
MC Asset Recovery	MC Asset Recovery, LLC.
MDE	Maryland Department of the Environment.
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
Mirant/RRI Merger	the merger completed on December 3, 2010 pursuant to the Mirant/RRI Merger Agreement.
Mirant/RRI Merger Agreement	the agreement by and among Mirant Corporation, RRI Energy, Inc. and RRI Energy Holdings, Inc. dated as of April 11, 2010.
Mirant Debtors	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and certain of its subsidiaries.
MISO	Midwest Independent Transmission System Operator.
mothballed	the unit has been removed from service and is unavailable for service, but has been laid up in a manner such that it can be brought back into service with an appropriate amount of notification, typically weeks or months.
MPSC	Maryland Public Service Commission.
MW	megawatt.

MWh megawatt hour.

NAAQS National Ambient Air Quality Standards.

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net generating capacity	net summer capacity.
NJDEP	New Jersey Department of Environmental Protection.
NOL	net operating loss.
NOV	notice of violation.
NO _x	nitrogen oxides.
NPDES	national pollutant discharge elimination system.
NRG	NRG Energy, Inc.
NRG Merger	the merger contemplated in the NRG Merger Agreement.
NRG Merger Agreement	the agreement by and among NRG Energy, Inc., Plus Merger Corporation and GenOn Energy, Inc. dated as of July 20, 2012.
NYISO	New York Independent System Operator.
NYMEX	New York Mercantile Exchange.
OCI	other comprehensive income.
OTC	over-the-counter.
PADEP	Pennsylvania Department of Environmental Protection.
peaking generating units	units designed to satisfy demand requirements during the periods of greatest or peak load on the system.
PEPCO	Potomac Electric Power Company.
PG&E	Pacific Gas & Electric Company.
PJM	PJM Interconnection, LLC.
Plan	the plan of reorganization that was approved in conjunction with Mirant Corporation's emergence from bankruptcy protection on January 3, 2006.
PPA	power purchase agreement.
Protective Charter Amendment	the Certificate of Amendment to our Third Restated Certificate of Incorporation dated May 4, 2011.
REMA	GenOn REMA, LLC and its subsidiaries, which include three generating facilities under operating leases.
retirement	the unit has been removed from service and is unavailable for service and not expected to return to service in the future.
RMR	reliability-must-run.
ROC	Risk Oversight Committee.
RRI Energy	RRI Energy, Inc., which changed its name to GenOn Energy, Inc. in connection with the Mirant/RRI Merger.

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RTO	regional transmission organization.
scrubbers	flue gas desulfurization emissions controls.
Securities Act	Securities Act of 1933, as amended.
SO ₂	sulfur dioxide.
Southern Company	The Southern Company.

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spark spread	the difference between power prices and the cost to generate electricity with natural gas.
Stone & Webster	Stone & Webster, Inc.
SWD	surface water discharge.
total margin capture factor	the actual gross margin for a unit from energy, and contracted and capacity divided by the total gross margin from energy, and contracted and capacity that could have been earned by the unit.
VaR	value at risk.
VIE	variable interest entity.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this report includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These statements involve known and unknown risks and uncertainties and relate to our revenues, income, capital structure and other financial items, future events, our future financial performance or our projected business results and our view of economic and market conditions. In some cases, one can identify forward-looking statements by words such as may, will, should, could, objective, projection, forecast, goal, guidance, outlook, expect, intend, seek, plan, think, target, potential or continue or the negative of these terms or comparable words.

Forward-looking statements are only predictions. Actual events or results may differ materially from any forward-looking statement as a result of various factors, which include:

- more stringent (or changes in the application of) environmental laws and regulations (including the cumulative effect of many such regulations) that restrict our ability or render it uneconomic to operate our assets, including regulations related to air emissions, disposal of ash and other byproducts, wastewater discharge and cooling water systems;
- changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities such as coal and natural gas in the energy markets, including efforts to reduce demand for electricity and to encourage the development of renewable sources of electricity, and the extent and timing of the entry of additional competition in our markets;
- legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the industry of generating, transmitting and distributing electricity (the electricity industry); changes in state, federal and other regulations affecting the electricity industry (including rate and other regulations); changes in tax laws and regulations to which we and our subsidiaries are subject; and changes in, or changes in the application of, other laws and regulations to which we and our subsidiaries and affiliates are or could become subject;
- conflicts between reliability needs and environmental rules, particularly with increasingly stringent environmental restrictions;
- price mitigation strategies employed by ISOs or RTOs that reduce our revenue and may result in a failure to compensate our generating units adequately for all of their costs;
- legal and political challenges to or changes in the rules used to calculate payments for capacity, energy and ancillary services or the establishment of bifurcated markets, incentives or other market design changes that give preferential treatment to new generating facilities over existing generating facilities;

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- the failure of our generating facilities to perform as expected, including outages for unscheduled maintenance or repair;
- our failure to use new or advanced power generation technologies;
- strikes, union activity or labor unrest;
- our ability to develop or recruit capable leaders and our ability to retain or replace the services of key employees;
- weather and other natural phenomena, including hurricanes and earthquakes;
- our failure to provide a safe working environment for our employees and visitors thereby increasing our exposure to additional liability, loss of productive time, other costs and a damaged reputation;

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- hazards customary to the power generation industry, including those listed in this cautionary statement and elsewhere in this report, and the possibility that we may not have adequate insurance to cover losses resulting from such hazards or the inability of our insurers to provide agreed upon coverage;
- our ability to execute our plan in respect of our Marsh Landing generating facility, including obtaining and maintaining the governmental authorizations necessary for construction and operation of the generating facility and completing the construction of the generating facility by mid-2013;
- our relative lack of geographic diversification of revenue sources resulting in concentrated exposure to the PJM market;
- our ability to enter into intermediate and long-term contracts to sell power or to hedge economically our expected future generation of power, and to obtain adequate supplies and deliveries of fuel for our generating facilities, at our required specifications and on terms and prices acceptable to us;
- failure to obtain adequate supplies of fuels, including from curtailments of the transportation of fuels;
- the cost and availability of emissions allowances;
- the curtailment of operations and reduced prices for electricity resulting from transmission constraints;
- the potential of additional limitation or loss of our income tax NOLs as a result of an ownership change as defined in IRC § 382;
- terrorist activities, cyberterrorism and inadequate cybersecurity, or the occurrence of a catastrophic loss and the possibility that we may not have adequate insurance to cover losses resulting from such hazards or the inability of our insurers to provide agreed upon coverage;
- deterioration in the financial condition of our counterparties, including financial counterparties, and the failure of such parties to pay amounts owed to us beyond collateral posted or to perform obligations or services due to us;
- poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties, and negative impacts on liquidity in the power and fuel markets in which we hedge economically and transact;

- increased credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of new or proposed laws, rules and regulations governing derivative financial instruments (such as the Dodd-Frank Act and related pending rulemaking proceedings);
- our inability to access effectively the OTC and exchange-based commodity markets or changes in commodity market conditions and liquidity, including as a result of new or proposed laws, rules and regulations governing derivative financial instruments (such as the Dodd-Frank Act and related pending rulemaking proceedings), which may affect our ability to engage in hedging and proprietary trading activities as expected, or may result in material losses from open positions;
- volatility in our gross margin as a result of changes in the fair value of our derivative financial instruments used in our hedging and proprietary trading activities and volatility in our cash flow from operations resulting from working capital requirements, including collateral, to support our hedging and proprietary trading activities;
- the disposition of pending or threatened litigation, including environmental litigation;

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- our ability to access contractors and equipment necessary to operate and maintain our generating facilities and to design, engineer, procure and construct capital improvements required or deemed advisable;

- the inability of our operating subsidiaries to generate sufficient cash to support our operations;

- the ability of lenders under our revolving credit facility and the Marsh Landing credit facility to perform their obligations;

- our consolidated indebtedness and the possibility that we or our subsidiaries may incur additional indebtedness in the future;

- restrictions on the ability of our subsidiaries to pay dividends, make distributions or otherwise transfer funds to us, including restrictions on GenOn Mid-Atlantic and REMA contained in their respective operating lease documents, which may affect our ability to access the cash flows of those subsidiaries to make debt service and other payments;

- our failure or inability to comply with provisions of our leases, loan agreements and debt, which may lead to a breach and, if not remedied, result in an event of default thereunder, which could result in such lessors, lenders and debt holders exercising remedies, limit access to needed liquidity and damage our reputation and relationships with financial institutions;

- covenants contained in our credit facilities, debt and leases that restrict our current and future operations, particularly our ability to respond to changes or take certain actions that may be in our long-term best interests;

- our ability to borrow additional funds and access capital markets; and

- the successful and timely completion of the proposed NRG Merger, which could be materially and adversely affected by, among other things, resolving any litigation brought in connection with the proposed NRG Merger, the timing and terms and conditions of required stockholder, governmental and regulatory approvals, and the ability to maintain relationships with employees, customers or suppliers as well as the ability to integrate the businesses and realize cost savings.

Many of these risks, uncertainties and assumptions are beyond our ability to control or predict. All forward-looking statements contained herein are expressly qualified in their entirety by cautionary statements contained throughout this report. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Furthermore, forward-looking statements speak only as of the date they are made. We undertake no obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this report.

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In addition to the discussion of certain risks in Management's Discussion and Analysis of Financial Condition and Results of Operations and the accompanying notes to GenOn's interim financial statements, other factors that could affect our future performance are set forth in our 2011 Annual Report on Form 10-K. Our filings and other important information are also available on our investor relations page at www.genon.com/investors.aspx.

Certain Terms

As used in this report, unless the context requires otherwise, we, us, our and GenOn refer to GenOn Energy, Inc. and its consolidated subsidiaries.

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PART I
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

GENON ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended June 30, 2012		Six Months Ended June 30, 2012	
	2011		2011	
	(in millions, except per share data)			
Operating revenues (including unrealized gains (losses) of \$(102), \$(36), \$41 and \$(135), respectively)	\$ 521	\$ 812	\$ 1,242	\$ 1,626
Cost of fuel, electricity and other products (including unrealized (gains) losses of \$40, \$(18), \$83 and \$(38), respectively)	306	390	584	791
Gross Margin (excluding depreciation and amortization)	215	422	658	835
Operating Expenses:				
Operations and maintenance	264	372	572	677
Depreciation and amortization	90	90	178	176
(Gain) loss on sales of assets, net		2	(8)	1
Total operating expenses	354	464	742	854
Operating Loss	(139)	(42)	(84)	(19)
Other Income (Expense), net:				
Interest expense	(85)	(96)	(174)	(205)
Other, net			2	(22)
Total other expense, net	(85)	(96)	(172)	(227)
Loss Before Income Taxes	(224)	(138)	(256)	(246)
Provision for income taxes	4		4	3
Net Loss	\$ (228)	\$ (138)	\$ (260)	\$ (249)
Basic and Diluted EPS:				
Basic EPS	\$ (0.30)	\$ (0.18)	\$ (0.34)	\$ (0.32)
Diluted EPS	\$ (0.30)	\$ (0.18)	\$ (0.34)	\$ (0.32)
Weighted average shares outstanding	774	772	774	771
Effect of dilutive securities				
Weighted average shares outstanding assuming dilution	774	772	774	771

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

Table of Contents**GENON ENERGY, INC. AND SUBSIDIARIES****CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS (UNAUDITED)**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Net Loss	\$ (228)	\$ (138)	\$ (260)	\$ (249)
Other Comprehensive Income (Loss), net of tax of \$0:				
Unrealized losses:				
Cash flow hedges interest rate swaps	(16)	(14)	(12)	(11)
Available-for-sale securities				(1)
Reclassifications to net loss:				
Pension and other postretirement benefits actuarial losses, net	2	1	4	2
Pension and other postretirement benefits prior service credit, net	(1)	(1)	(2)	(2)
Other, net	1		1	
Other Comprehensive Loss	(14)	(14)	(9)	(12)
Comprehensive Loss	\$ (242)	\$ (152)	\$ (269)	\$ (261)

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2012	December 31, 2011
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 1,677	\$ 1,668
Funds on deposit	247	422
Receivables, net	341	357
Derivative contract assets	890	999
Inventories	497	563
Prepaid rent and other expenses	139	167
Total current assets	3,791	4,176
Property, plant and equipment, gross	7,628	7,351
Accumulated depreciation and amortization	(1,302)	(1,160)
Property, Plant and Equipment, net	6,326	6,191
Noncurrent Assets:		
Intangible assets, net	45	48
Derivative contract assets	743	733
Deferred income taxes	263	294
Prepaid rent	436	386
Other	414	441
Total noncurrent assets	1,901	1,902
Total Assets	\$ 12,018	\$ 12,269
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	\$ 10	\$ 10
Accounts payable and accrued liabilities	846	790
Derivative contract liabilities	614	720
Deferred income taxes	263	294
Other	88	130
Total current liabilities	1,821	1,944
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,267	4,122
Derivative contract liabilities	190	131
Pension and postretirement obligations	252	259
Other	632	696
Total noncurrent liabilities	5,341	5,208
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, par value \$.001 per share, authorized 125,000,000 shares, no shares issued at June 30, 2012 and December 31, 2011		
Common stock, par value \$.001 per share, authorized 2.0 billion shares, issued 772,898,703 shares and 771,692,734 shares at June 30, 2012 and December 31, 2011, respectively	1	1
Additional paid-in capital	7,457	7,449
Accumulated deficit	(2,423)	(2,163)
Accumulated other comprehensive loss	(179)	(170)
Total stockholders equity	4,856	5,117
Total Liabilities and Stockholders Equity	\$ 12,018	\$ 12,269

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GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30,	
	2012	2011
	(in millions)	
Cash Flows from Operating Activities:		
Net loss	\$ (260)	\$ (249)
Adjustments to reconcile net loss and changes in operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	186	183
Amortization of acquired contracts	(22)	(19)
(Gain) loss on sales of assets, net	(8)	1
Unrealized losses	42	97
Stock-based compensation expense	9	8
Excess materials and supplies inventory reserve	35	
Lower of cost or market inventory adjustments	65	1
Loss on early extinguishment of debt		23
Advance settlement of out-of-market contract obligation	(20)	
Reversal of Potomac River settlement obligation	(31)	
Large scale remediation and settlement costs	(3)	30
Other, net	2	
Changes in operating assets and liabilities	33	(60)
Total adjustments	288	264
Net cash provided by operating activities	28	15
Cash Flows from Investing Activities:		
Capital expenditures	(342)	(183)
Proceeds from the sales of assets	14	12
Restricted funds on deposit, net	167	1,418
Net cash provided by (used in) investing activities	(161)	1,247
Cash Flows from Financing Activities:		
Proceeds from long-term debt	148	9
Repayment of long-term debt	(6)	(2,072)
Other, net		1
Net cash provided by (used in) financing activities	142	(2,062)
Net Increase (Decrease) in Cash and Cash Equivalents	9	(800)
Cash and Cash Equivalents, beginning of period	1,668	2,402
Cash and Cash Equivalents, end of period	\$ 1,677	\$ 1,602
Supplemental Disclosures:		
Cash paid for interest, net of amounts capitalized	\$ 165	\$ 213
Cash paid for income taxes (net of refunds received)	\$ 11	\$ (6)

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Description of Business and Accounting and Reporting Policies

Background

We are a wholesale generator with approximately 22,700 MW of net electric generating capacity located, in many cases, near major metropolitan load centers in the PJM, MISO, Northeast and Southeast regions, and California. We also operate integrated asset management and proprietary trading operations. See note 2 for a discussion of generating facilities in the Eastern PJM, Western PJM/MISO and California segments that have units we have deactivated or expect to deactivate between 2012 and 2015.

We were formed as a Delaware corporation in August 2000. We, us, our and GenOn refer to GenOn Energy, Inc. and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Mirant/RRI Merger.

On July 20, 2012, we entered into the NRG Merger Agreement with NRG Energy, Inc. and a direct wholly-owned subsidiary of NRG. See note 11.

Basis of Presentation

The consolidated interim financial statements and notes (interim financial statements) are unaudited, omit certain disclosures and should be read in conjunction with our audited consolidated financial statements and notes in our 2011 Annual Report on Form 10-K. These interim financial statements have been prepared in accordance with GAAP from records maintained by us. All significant intercompany accounts and transactions have been eliminated in consolidation. The interim financial statements reflect all normal recurring adjustments necessary, in management's opinion, to present fairly our financial position and results of operations for the reported periods. Amounts reported for interim periods may not be indicative of a full year period because of seasonal fluctuations in demand for electricity and energy services, changes in commodity prices, and changes in regulations, timing of maintenance and other expenditures, dispositions, changes in interest expense and other factors.

At June 30, 2012 and December 31, 2011, substantially all of our subsidiaries are wholly-owned and located in the United States. We do not consolidate five power generating facilities, which are under operating leases; a 50% equity investment in a cogeneration facility; and a VIE (MC Asset Recovery) for which we are not the primary beneficiary. See note 10 for further discussion of MC Asset Recovery.

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The preparation of interim financial statements in conformity with GAAP requires management to make various estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the interim financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. Our significant estimates include:

- estimating the fair value of certain derivative contracts;
- estimating the inventory reserve;
- estimating future taxable income in evaluating the deferred tax asset valuation allowance;
- estimating the useful lives of long-lived assets;
- estimating future costs and the valuation of asset retirement obligations;
- estimating future cash flows in determining impairments of long-lived assets and definite-lived intangible assets;

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- estimating the fair value and expected return on plan assets, discount rates and other actuarial assumptions used in estimating pension and other postretirement benefit plan liabilities; and
- estimating losses to be recorded for contingent liabilities.

We evaluate events that occur after the balance sheet date but before the financial statements are issued for potential recognition or disclosure. Based on the evaluation, we determined that there were no material subsequent events for recognition or disclosure other than those disclosed herein.

Our results of operations for the three and six months ended June 30, 2011 have been retroactively amended for the revisions to the provisional purchase price allocation in connection with the Mirant/RRI Merger.

We had disclosed in our 2011 Annual Report on Form 10-K that it was possible that RRI Energy had experienced an ownership change under the applicable tax rules as a result of the Mirant/RRI Merger. Based on further inquiries, we do not think that RRI Energy experienced an ownership change as a result of the Mirant/RRI Merger or following the Mirant/RRI Merger through December 31, 2011.

Funds on Deposit

Funds on deposit are included in current and noncurrent assets in the consolidated balance sheets. Funds on deposit include the following:

	June 30, 2012	(in millions)	December 31, 2011
Cash collateral posted energy trading and marketing	\$	153	\$ 185
Cash collateral posted other operating activities(1)		62	39
Cash collateral posted surety bonds(2)		34	34
GenOn Marsh Landing development project cash collateral posted(3)		85	131
Environmental compliance deposits(4)		35	34
GenOn Mid-Atlantic restricted cash(5)			166
Other		27	16
Total current and noncurrent funds on deposit		396	605
Less: Current funds on deposit		247	422
Total noncurrent funds on deposit	\$	149	\$ 183

(1) Includes \$32 million related to the Potomac River obligation under the 2008 agreement with the City of Alexandria. See note 2.

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- (2) Represents cash under surety bonds posted primarily with the PADEP related to environmental obligations.
- (3) Represents cash-collateralized letters of credit to support the Marsh Landing development project.
- (4) Represents deposits with the State of Pennsylvania to guarantee our obligations related to future closures of coal ash landfill sites and with the State of New Jersey to satisfy our obligations to remediate site contamination. See note 10.
- (5) Represents cash reserved in respect of interlocutory liens related to the scrubber contract litigation, which was settled in June 2012. See note 10.

Table of Contents***Inventories***

Inventories were comprised of the following:

	June 30, 2012	(in millions)		December 31, 2011
Fuel inventory:				
Coal	\$	201	\$	229
Fuel oil		84		108
Natural gas				1
Other		3		5
Materials and supplies(1)		166		201
Purchased emissions allowances		43		19
Total inventories	\$	497	\$	563

(1) Amount is net of an inventory reserve of \$35 million and \$0 at June 30, 2012 and December 31, 2011, respectively. See note 2.

During the three months ended June 30, 2012 and 2011, we recorded \$19 million and \$1 million, respectively, and during the six months ended June 30, 2012 and 2011, we recorded \$65 million and \$1 million, respectively, for lower of average cost or market valuation adjustments in cost of fuel, electricity and other products.

Capitalization of Interest Cost

We incurred the following interest costs:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Total interest costs	\$	94	\$	99
Capitalized and included in property, plant and equipment, net		(9)		(3)
Interest expense	\$	85	\$	96
			\$	174
			\$	205

The amounts of capitalized interest above include interest accrued. During the three months ended June 30, 2012 and 2011, cash paid for interest was \$164 million and \$201 million, respectively, of which \$10 million and \$4 million, respectively, were capitalized. During the six months ended June 30, 2012 and 2011, cash paid for interest was \$180 million and \$218 million, respectively, of which \$15 million and \$5 million, respectively, were capitalized.

Guarantees and Indemnifications

We generally conduct business through various operating subsidiaries which enter into contracts as part of their business activities. In certain instances, the contractual obligations of such subsidiaries are guaranteed by, or otherwise supported by, us or another of our subsidiaries, including by letters of credit issued under the GenOn credit facilities. See note 4.

In addition, we, including our subsidiaries, enter into various contracts that include indemnification and guarantee provisions. Examples of these contracts include financing and lease arrangements, purchase and sale agreements, agreements to purchase or sell commodities, construction agreements and agreements with vendors. Although the primary obligation under such contracts is to pay money or render performance, such contracts may include obligations to indemnify the counterparty for damages arising from the breach thereof and, in certain instances, other existing or potential liabilities. In many cases, our maximum potential liability cannot be estimated because some of the underlying agreements contain no limits on potential liability.

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We have guaranteed some non-qualified benefits of CenterPoint's existing retirees at September 20, 2002. The estimated maximum potential amount of future payments under the guarantee is \$55 million at June 30, 2012 and \$3 million is recorded in the consolidated balance sheet for this item.

Recently Adopted Accounting Guidance

Fair Value Measurement and Disclosure. We adopted FASB accounting guidance for the quarter ended March 31, 2012 that requires disclosure of the following:

- quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy;

- for those fair value measurements categorized within Level 3 of the fair value hierarchy, both the valuation processes used and the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any; and

- the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

See note 3 for these additional disclosures.

Comprehensive Income. We adopted FASB accounting guidance for the quarter ended March 31, 2012 that requires companies to report the components of comprehensive income in either (a) a continuous statement of comprehensive income or (b) two separate but consecutive statements. The guidance does not change the items that must be reported in comprehensive income. See the consolidated statements of comprehensive loss and note 8.

New Accounting Guidance Not Yet Adopted at June 30, 2012

Balance Sheet Offsetting. In December 2011, the FASB issued updated guidance to provide enhanced disclosures such that users of the financial statements will be able to better evaluate the effect or potential effect of netting arrangements in the balance sheet. The guidance requires improved information about financial instruments and derivative instruments that are either offset according to specific guidance or subject to an enforceable master netting agreement or similar arrangement. The disclosures will provide both net and gross information for these assets and liabilities. Although we do not currently elect to offset assets and liabilities within the scope of the guidance, expanded disclosures will be required starting for the quarter ended March 31, 2013, along with retrospective presentation of prior periods.

2. Expected Retirements, Mothballing or Long-Term Protective Layup of Generating Facilities

Facilities Announced in February and March 2012

We are subject to extensive environmental regulation by federal, state and local authorities under a variety of statutes, regulations and permits that address discharges into the air, water and soil, and the proper handling of solid, hazardous and toxic materials and waste. Complying with increasingly stringent environmental requirements involves significant capital and operating expenses. To the extent forecasted returns on investments necessary to comply with environmental regulations are insufficient for a particular facility, we plan to deactivate that facility. In determining the forecasted returns on investments, we factor in forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes and other factors. We deactivated the following coal-fired units at the referenced times: Niles unit 2 (108 MW) June 2012 and Elrama units 1-3 (289 MW) mothballed June 2012 (plan to retire in March 2014). We expect to deactivate the following generating capacity, primarily coal-fired units, at the referenced times: Niles unit 1 (109 MW) October 2012, Elrama unit 4 (171 MW) mothball October 2012 (plan to retire in March 2014), Portland (401 MW) January 2015, Avon Lake (732 MW) April 2015, New Castle (330 MW) April 2015, Titus (243 MW) April 2015, Shawville (597 MW) place in long-term protective layup in April 2015 and Glen Gardner (160 MW) May 2015. We filed for RMR arrangements for Niles unit 1 and Elrama unit 4 that are in effect from June 1 through September 30, 2012. These RMR arrangements are subject to final FERC rulings.

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Potomac River Generating Facility

During 2011, we entered into an agreement with the City of Alexandria, Virginia to remove permanently from service our Potomac River generating facility. The agreement, which amends our Project Schedule and Agreement, dated July 2008 with the City of Alexandria, provides for the retirement of the Potomac River generating facility on October 1, 2012, subject to the determination of PJM that the retirement of the facility will not affect reliability and the consent of PEPCO. PJM made the necessary determination and in June 2012 PEPCO gave its consent. As a result, the Potomac River generating facility will be retired on October 1, 2012. Upon retirement of the Potomac River generating facility, all funds in the escrow account (\$32 million) established under the July 2008 agreement will be distributed to us, provided, that, if the retirement of the facility occurs after January 1, 2014, \$750,000 of such funds will be paid to the City of Alexandria. We therefore reversed \$31 million of the previously recorded obligation under the 2008 agreement with the City of Alexandria as a reduction in operations and maintenance expense during the three months ended June 30, 2012.

Contra Costa Generating Facility

We entered into an agreement with PG&E in September 2009 for 674 MW at Contra Costa for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approvals, we have agreed to retire the Contra Costa facility.

Expenses, Property, Plant and Equipment, and Materials and Supplies Inventory Related to Deactivations

In connection with our decision to deactivate the generating facilities, we evaluated our materials and supplies inventory and determined that we have excess inventory. We established a reserve of \$35 million (or \$(0.04) per basic share) recorded to operations and maintenance expense during the three months ended March 31, 2012 relating to our excess inventory. We will continue to monitor the inventory balances and could have changes to the reserve in the future. At June 30, 2012, the aggregate carrying value of property, plant and equipment, net and materials and supplies inventory, net for the ten generating facilities to be deactivated was \$181 million and \$25 million, respectively. In addition to the excess materials and supplies inventory reserve recorded in the first quarter, we incurred \$3 million during the three months ended June 30, 2012 for costs to deactivate generating facilities, which is included in operations and maintenance expense. We expect to incur additional costs in the future in connection with the deactivations, such as severance and other shutdown costs.

3. Financial Instruments

Derivatives and Hedging Activities

In connection with the business of generating electricity, we are exposed to energy commodity price risk associated with the acquisition of fuel and emissions allowances needed to generate electricity, the price of electricity produced and sold, and the fair value of fuel inventories. Through our asset management activities, we enter into a variety of exchange-traded and OTC energy and energy-related derivative financial instruments, such as forward contracts, futures contracts, option contracts and financial swap agreements to manage exposure to commodity price risks. These contracts have varying terms and durations, which range from a few days to years, depending on the instrument. Our

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proprietary trading activities also utilize similar derivative contracts in markets where we have a physical presence to attempt to generate incremental gross margin. Our fuel oil management activities use derivative financial instruments to hedge economically the fair value of physical fuel oil inventories, optimize the approximately two million barrels of storage capacity that we own, and attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. The open positions in our trading activities comprising proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

Derivative financial instruments are recorded in the consolidated balance sheets at fair value, except for derivative contracts that qualify for and for which we have elected the normal purchase or normal sale exceptions, which are not reflected in the consolidated balance sheet or results of operations prior to accrual of the settlement. We present our derivative contract assets and liabilities on a gross basis (regardless of master netting arrangements with the same counterparty). Cash collateral amounts are also presented on a gross basis.

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During the second quarter of 2012, we could no longer assert that physical delivery was probable for the remaining coal agreements for which we had elected the normal purchase exception. As such, the normal purchase exception was removed, and we recorded the fair value of these contracts on the balance sheet at June 30, 2012 as a net derivative liability of \$49 million and immediately recognized that amount in earnings as unrealized losses in cost of fuel, electricity and other products.

If certain criteria are met, a derivative financial instrument may be designated as a fair value hedge or cash flow hedge. In 2010, GenOn Marsh Landing entered into interest rate protection agreements (interest rate swaps) in connection with its project financing, which have been designated as cash flow hedges. GenOn Marsh Landing entered into the interest rate swaps to reduce the risks with respect to the variability of the interest rates for the term loan. With the exception of these interest rate swaps, we did not have any other derivative financial instruments designated as fair value or cash flow hedges for accounting purposes during the six months ended June 30, 2012 or 2011.

The changes in fair value of cash flow hedges are deferred in accumulated other comprehensive loss, net of tax, to the extent the contracts are, or have been, effective as hedges, until the forecasted transactions affect earnings. We record immediately into earnings the ineffective portion of changes in fair value of cash flow hedges.

Derivative financial instruments designated as cash flow hedges must have a high correlation between price movements in the derivative and the hedged item. If and when an acceptable level of correlation no longer exists, hedge accounting ceases and changes in fair value are recognized in our results of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the related deferred gains or losses in our results of operations. Changes in fair value of the associated hedging instrument are then recognized immediately in earnings for the remainder of the contract term unless a new hedging relationship is designated.

For our derivative financial instruments that have not been designated as cash flow hedges for accounting purposes, changes in such instruments fair values are recognized currently in earnings. Our derivative financial instruments are categorized based on the business objective the instrument is expected to achieve: asset management or trading, which includes proprietary trading and fuel oil management. For asset management activities, changes in fair value and settlement of derivative financial instruments used to hedge electricity economically are reflected in operating revenue and changes in fair value and settlement of derivative financial instruments used to hedge fuel economically are reflected in cost of fuel, electricity and other products in the consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the consolidated statements of operations.

We also consider risks associated with interest rates, counterparty credit and our own non-performance risk when valuing derivative financial instruments. The nominal value of the derivative contract assets and liabilities is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of the transactions being valued.

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The following table presents the fair value of derivative financial instruments:

	Derivative Contract Assets		Derivative Contract Liabilities		Net Derivative Contract Assets (Liabilities)
	Current	Long-Term	Current	Long-Term	
June 30, 2012					
<u>Commodity Contracts:</u>					
Asset management	\$ 580	\$ 734	\$ (304)	\$ (140)	\$ 870
Trading activities	310	9	(307)	(9)	3
Total commodity contracts	890	743	(611)	(149)	873
<u>Interest Rate Contracts</u>					
Total derivatives	\$ 890	\$ 743	\$ (614)	\$ (190)	\$ 829
December 31, 2011					
<u>Commodity Contracts:</u>					
Asset management	\$ 538	\$ 730	\$ (255)	\$ (97)	\$ 916
Trading activities	461	3	(464)	(3)	(3)
Total commodity contracts	999	733	(719)	(100)	913
<u>Interest Rate Contracts</u>					
Total derivatives	\$ 999	\$ 733	\$ (720)	\$ (131)	\$ 881

The following table presents the net gains (losses) for derivative financial instruments recognized in income in the consolidated statements of operations:

Derivatives Not Designated as Hedging Instruments	Three Months Ended June 30,				
	2012	Cost of Fuel, Electricity and Other Products		2011	Cost of Fuel, Electricity and Other Products
	Operating Revenues	(in millions)		Operating Revenues	
<u>Asset Management Commodity Contracts:</u>					
Unrealized	\$ (113)	\$ (40)	\$ (48)	\$ 18	
Realized(1)(2)	142	(12)	61	(14)	
Total asset management	\$ 29	\$ (52)	\$ 13	\$ 4	
<u>Trading Commodity Contracts:</u>					
Unrealized	\$ 11	\$	\$ 12	\$	
Realized(1)(2)			(1)		
Total trading	\$ 11	\$	\$ 11	\$	
Total derivatives	\$ 40	\$ (52)	\$ 24	\$ 4	

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Derivatives Not Designated as Hedging Instruments	Six Months Ended June 30,			
	2012	Cost of Fuel, Electricity and Other Products		2011
	Operating Revenues	Electricity and Other Products	Operating Revenues	Cost of Fuel, Electricity and Other Products
	(in millions)			
Asset Management Commodity Contracts:				
Unrealized	\$ 37	\$ (83)	\$ (123)	\$ 38
Realized(1)(2)	326	(28)	140	(57)
Total asset management	\$ 363	\$ (111)	\$ 17	\$ (19)
Trading Commodity Contracts:				
Unrealized	\$ 4	\$	\$ (12)	\$
Realized(1)(2)	(5)		5	
Total trading	\$ (1)	\$	\$ (7)	\$
Total derivatives	\$ 362	\$ (111)	\$ 10	\$ (19)

- (1) Represents the total cash settlements of derivative financial instruments during each reporting period (composed of the sum of the quarterly settlements) that existed at the beginning of each respective period.
- (2) Excludes settlement value of fuel contracts classified as inventory.

The following table presents the losses on the interest rate swaps designated as cash flow hedges in the consolidated statements of operations and comprehensive income/loss:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Recognized in earnings on derivatives(1)(2)	\$	\$	\$	\$
Valuation adjustments(3)		(2)		

- (1) Represents the ineffective portion of the interest rate swaps classified as cash flow hedges and recorded in interest expense.
- (2) All of the forecasted transactions (future interest payments) were deemed probable of occurring; therefore, no cash flow hedges were discontinued and no amount was recognized in our results of operations as a result of discontinued cash flow hedges.
- (3) Represents the default risk of the counterparties to these transactions and our own non-performance risk. The effect of these valuation adjustments is recorded in interest expense.

At June 30, 2012, the maximum length of time we are hedging our exposure to the variability in future cash flows that may result from changes in interest rates is 11 years. Because a significant portion of the interest expense incurred by GenOn Marsh Landing during construction will be capitalized, amounts included in accumulated other comprehensive loss associated with construction period interest payments will be reclassified to property, plant and equipment and depreciated over the expected useful life of the Marsh Landing generating facility once it commences commercial operations in mid-2013. Actual amounts reclassified into earnings could vary from the amounts currently recorded as a result of future changes in interest rates. See note 8 for the effect of the cash flow hedges in comprehensive income/loss.

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The following tables present the notional quantity on long (short) positions for derivative financial instruments:

Derivative Instruments	Notional Volumes at June 30, 2012		Net Derivative Contracts
	Derivative Contract Assets	Derivative Contract Liabilities (in millions)	
Commodity Contracts (in equivalent MWh):			
Power(1)	(111)	43	(68)
Natural gas		3	3
Coal	(1)	21	20
Interest Rate Contracts (in dollars)(2)		475	475

Derivative Instruments	Notional Volumes at December 31, 2011		Net Derivative Contracts
	Derivative Contract Assets	Derivative Contract Liabilities (in millions)	
Commodity Contracts (in equivalent MWh):			
Power(1)	(130)	73	(57)
Natural gas	(8)	10	2
Coal	3	12	15
Interest Rate Contracts (in dollars)(2)		475	475

(1) Includes MWh equivalent of natural gas transactions used to hedge power economically.

(2) Beginning in mid-2013, the notional amount will increase to \$500 million.

Fair Value Measurements

Fair Value Hierarchy and Valuation Techniques. We apply recurring fair value measurements to our financial assets and liabilities. In estimating fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. The fair value measurement inputs we use vary from readily observable prices for exchange-traded instruments to price curves that cannot be validated through external pricing sources. Based on the observability of the inputs used in the valuation techniques, the financial assets and liabilities carried at fair value in the financial statements are classified as follows:

Level 1: Represents unadjusted quoted market prices in active markets for identical assets or liabilities that are accessible at the measurement date. This category primarily includes natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices. Interest bearing funds and trading securities are also valued using Level 1 inputs.

Level 2: Represents quoted market prices for similar assets or liabilities in active markets, quoted market prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. This category primarily includes non-exchange traded derivatives such as OTC forwards, swaps and options, and certain energy derivative instruments that are cleared and settled through exchanges. This category also includes the interest rate swaps.

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Level 3: Represents commodity derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from market sources (such as implied volatilities and correlations). The OTC, complex or structured derivative instruments that are transacted in less liquid markets with limited pricing information are included in Level 3. Examples are coal contracts, power transmission congestion products, less liquid power and natural gas contracts, and options valued using internally developed inputs.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls must

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be determined based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and consideration of factors specific to the asset or liability.

A significant amount of the fair value of our derivative contract assets and liabilities is based on observable quoted prices from exchanges and indicative quoted prices from independent brokers in active markets that regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. We think that these prices represent the best available information for valuation purposes. In determining the fair value of derivative contract assets and liabilities, we use third-party market pricing where available. For transactions classified in Level 1 of the fair value hierarchy, we use the unadjusted published settled prices on the valuation date. For transactions classified in Level 2 of the fair value hierarchy, we value these transactions using indicative quoted prices from independent brokers or other widely-accepted valuation methodologies. Transactions are classified in Level 2 if substantially all (greater than 90%) of the fair value can be corroborated using observable market inputs such as transactable broker quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for assets and ask prices for liabilities. The quotes we obtain from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. We typically obtain multiple broker quotes as of the valuation date that extend for the tenor of the underlying contracts for each delivery location. The number of quotes that we can obtain depends on the relative liquidity of the delivery location on the valuation date. If multiple broker quotes are received for a contract, we use an average of the quoted bid or ask prices. If only one broker quote is received for a delivery location and it cannot be validated through other external sources, we will assign the quote to a lower level within the fair value hierarchy. In some instances, we may combine broker quotes for a liquid delivery hub with broker quotes for the price spread between the liquid delivery hub and the delivery location under the contract. We also may apply interpolation techniques to value monthly strips if broker quotes are only available on a seasonal or annual basis. We perform validation procedures on the broker quotes at least monthly. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may exclude from consideration a broker quote if it is a clear outlier and other quotes are obtained. At June 30, 2012, we obtained broker quotes for 100% of our delivery locations classified in Level 2 of the fair value hierarchy.

Inactive markets are considered to be those markets with few transactions, noncurrent pricing or prices that vary over time or among market makers. Our transactions in Level 3 of the fair value hierarchy may involve transactions whereby observable market data, such as broker quotes, are not available for substantially all of the tenor of the contract or we are only able to obtain indicative broker quotes that cannot be corroborated by observable market data. In such cases, we may apply valuation techniques such as extrapolation and other quantitative methods to determine fair value. Our techniques for fair value estimation include assumptions for market prices, including market price volatility and the volatility of the spread between multiple market prices. Proprietary models may also be used to estimate the fair value of derivative contract assets and liabilities that may be structured or otherwise tailored. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. At June 30, 2012, the assets and liabilities classified as Level 3 in the fair value hierarchy represented 4% of total derivative contract assets and 24% of total derivative contract liabilities.

The fair value of our derivative contract assets and liabilities is also affected by assumptions as to time value, credit risk and non-performance risk. The nominal value of derivatives is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of the transaction. Derivative contract assets are reduced to reflect the estimated default risk of counterparties on their contractual obligations. The counterparty default risk for our overall net position is measured based on published spreads on credit default swaps for counterparties, where available, or proxies based upon published spreads, applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. The fair value of derivative contract liabilities is reduced to reflect the estimated risk of default on contractual obligations to counterparties and is measured based on published default rates of our debt, where available, or proxies based upon published spreads. Credit risk and non-performance risk are calculated with consideration of our master netting agreements with counterparties and our exposure is reduced by cash collateral posted to us against these obligations.

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Information about Sensitivity to Changes in Significant Unobservable Inputs. The significant unobservable inputs used in the fair value measure of our commodity instruments categorized within Level 3 of the fair value hierarchy are estimates of future market volatility, estimates of forward congestion power price spreads and estimates of counterparty credit risk and our own non-performance risk. These assumptions are generally independent of each other. Volatility curves and power prices spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price or volatility of the spread on a long position would result in a higher fair value measurement. Increases in the price or volatility of the spread on a short position would result in a lower fair value measurement. A change in the assumption used for the probability of default is accompanied by a directionally similar change in the adjustment to reflect the estimated default risk of counterparties on their contractual obligations, or the estimated risk of default on our own contractual obligations to counterparties.

Risk Management. The Risk and Finance Oversight Committee of the Board of Directors is responsible for oversight of the risk management of our commercial activities and enterprise risk management. In order to ensure proper daily oversight of our commercial risk controls, the Risk and Finance Oversight Committee has established the ROC with membership determined by the Chief Executive Officer. The ROC is responsible for ensuring that the necessary policies, procedures and systems are in place to measure, monitor and report on the risks associated with our commercial activities. The ROC is also responsible for safeguarding proprietary models against the negative impact of inadequate model control by providing oversight and control to model development, back-testing and verification, automation, security and revision control. The ROC must approve new valuation models or fundamental modifications to existing models. Model forecasts are back-tested annually and the results reviewed with the ROC.

Comprehensive, accurate and timely reporting and monitoring is essential to effectively manage market, credit and operational risks and to protect against large unanticipated losses. Management has established reporting and monitoring functions, which include daily and weekly reporting, to inform the ROC and Chief Risk Officer of its activities. The chair of the ROC reports to the Risk and Finance Oversight Committee on a quarterly basis, or more frequently, if events and circumstances dictate.

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Fair Value of Derivative Instruments and Certain Other Assets. The fair value measurements of financial assets and liabilities by class are as follows:

	June 30, 2012				Total Fair Value
	Level 1(1)	Level 2(1)(2)	Level 3	(in millions)	
Derivative contract assets:					
Commodity Contracts					
Asset Management:					
Power	\$ 148	\$ 1,137	\$ 18		\$ 1,303
Fuel	2	2	7 ⁽³⁾		11
Total Asset Management	150	1,139	25		1,314
Trading Activities	44	241	34		319
Total derivative contract assets	\$ 194	\$ 1,380	\$ 59	\$	1,633
Derivative contract liabilities:					
Commodity Contracts					
Asset Management:					
Power	\$ 54	\$ 204	\$ 4		\$ 262
Fuel	7	2	173 ⁽³⁾		182
Total Asset Management	61	206	177		444
Trading Activities	51	252	13		316
Interest Rate Contracts		44			44
Total derivative contract liabilities	\$ 112	\$ 502	\$ 190	\$	804
Interest-bearing funds ⁽⁴⁾	\$ 1,808			\$	1,808
Other assets ⁽⁵⁾	\$ 20			\$	20

-
- (1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no transfers during the six months ended June 30, 2012.
 - (2) Option contracts comprised 1% of net derivative contract assets.
 - (3) Primarily relates to coal.
 - (4) Represents investments in money market funds and treasury bills and is included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. Of interest-bearing funds, we had \$1.664 billion included in cash and cash equivalents, \$35 million included in funds on deposit and \$109 million included in other noncurrent assets.
 - (5) Relates to mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

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	December 31, 2011				Total Fair Value
	Level 1(1)	Level 2(1)(2)	Level 3	(in millions)	
Derivative contract assets:					
Commodity Contracts					
Asset Management:					
Power	\$ 102	\$ 1,136	\$ 19	\$ 1,257	
Fuel	2		9(3)	11	
Total Asset Management	104	1,136	28	1,268	
Trading Activities	124	302	38	464	
Total derivative contract assets	\$ 228	\$ 1,438	\$ 66	\$ 1,732	
Derivative contract liabilities:					
Commodity Contracts					
Asset Management:					
Power	\$ 45	\$ 206	\$ 2	\$ 253	
Fuel	19	1	79(3)	99	
Total Asset Management	64	207	81	352	
Trading Activities	142	309	16	467	
Interest Rate Contracts		32		32	
Total derivative contract liabilities	\$ 206	\$ 548	\$ 97	\$ 851	
Interest-bearing funds(4)	\$ 1,985	\$	\$	\$ 1,985	
Other assets(5)	\$ 20	\$	\$	\$ 20	

-
- (1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no significant transfers during 2011.
- (2) Option contracts comprised 1% of net derivative contract assets.
- (3) Primarily relates to coal.
- (4) Represents investments in money market funds and is included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. Of interest-bearing funds, we had \$1.626 billion included in cash and cash equivalents, \$202 million included in funds on deposit and \$157 million included in other noncurrent assets.
- (5) Relates to mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

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The following is a reconciliation of changes (comprised of the sum of the quarterly changes) in fair value of net commodity derivative contract assets and liabilities classified as Level 3 during the six months ended June 30, 2012 and 2011:

	Net Derivatives Contracts (Level 3)		
	Asset Management	Trading Activities (in millions)	Total
Balance, January 1, 2012 (net asset (liability))	\$ (53)	\$ 22	\$ (31)
Total gains (losses) realized/unrealized:			
Included in earnings(1)	(129)	21	(108)
Purchases(2)			
Issuances(2)			
Settlements(3)	30	(22)	8
Transfers into Level 3(4)			
Transfers out of Level 3(4)			
Balance, June 30, 2012 (net asset (liability))	\$ (152)	\$ 21	\$ (131)
Balance, January 1, 2011 (net asset (liability))	\$ (70)	\$ 2	\$ (68)
Total gains (losses) realized/unrealized:			
Included in earnings (1)	33	4	37
Purchases(2)			
Issuances(2)			
Settlements(3)	6	(2)	4
Transfers into Level 3(4)			
Transfers out of Level 3(4)			
Balance, June 30, 2011 (net asset (liability))	\$ (31)	\$ 4	\$ (27)

-
- (1) Represents the fair value, as of the end of each reporting period, of Level 3 contracts entered into during each reporting period and the gains and losses attributable to Level 3 contracts that existed as of the beginning of each reporting period and were still held at the end of each reporting period.
 - (2) Contracts entered into during each reporting period are reported with other changes in fair value.
 - (3) Represents the reversal of previously recognized unrealized gains and losses from settlement of contracts during each reporting period.
 - (4) Denotes the total contracts that existed at the beginning of each reporting period and were still held at the end of each reporting period that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during each reporting period. Amounts reflect fair value as of the end of each reporting period.

The following table presents the amounts included in income related to derivative contract assets and liabilities classified as Level 3:

Operating Revenues	2012 Cost of Fuel,	Three Months Ended June 30,		2011 Cost of Fuel,	Total
		Total	Operating Revenues		
	Electricity			Electricity	
	and Other			and Other	

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	Products				Products							
	(in millions)											
Gains (losses) included in income	\$	(43)	\$	(52)	\$	(95)	\$	2	\$	19	\$	21
Gains (losses) included in income (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at June 30	\$	(39)	\$	(92)	\$	(131)	\$	3	\$	19	\$	22

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	Six Months Ended June 30,					
	2012 Cost of Fuel, Electricity and Other Products			2011 Cost of Fuel, Electricity and Other Products		
Operating Revenues	Operating Revenues	Total	Operating Revenues	Operating Revenues	Products	Total
	(in millions)					
Gains (losses) included in income	\$ (4)	\$ (96)	\$ (100)	\$ 6	\$ 35	\$ 41
Gains (losses) included in income (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at June 30	\$ (1)	\$ (135)	\$ (136)	\$ 7	\$ 34	\$ 41

Information about Sensitivity to Changes in Significant Unobservable Inputs. The following table presents the range of sensitivity of unobservable inputs used in fair value measurements categorized within Level 3 of the fair value hierarchy:

	Net Fair Value at June 30, 2012 (in millions)	Quantitative Information about Level 3 Fair Value Measurements(1)			Range (Weighted Average)
		Techniques	Unobservable Input		
Credit valuation adjustment	\$ 5	Internal model	Own credit risk		20% to (20)%(2)

- (1) Excludes immaterial unobservable inputs related to power transmission congestion products, power swaps, spread options, physical gas premiums on transactions and credit valuation adjustment related to counterparty credit risk.
- (2) Represents the range of the credit default swap spread curves used in the valuation analysis that we think market participants might use when pricing the contracts.

At June 30, 2012, net fair value asset of \$32 million for power transactions and net fair value liability of \$167 million for fuel transactions classified as Level 3 were priced based on unadjusted indicative broker quotes that cannot be corroborated by observable market data. Quantitative information is excluded for these fair value measurements.

Counterparty Credit Concentration Risk

We are exposed to the default risk of the counterparties with which we transact. We manage our credit risk by entering into master netting agreements and requiring most counterparties to post cash collateral or other credit enhancements based on the net exposure and the credit standing of the counterparty. We also have non-collateralized power hedges entered into by GenOn Mid-Atlantic. These transactions are senior

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unsecured obligations of GenOn Mid-Atlantic and the counterparties and have not required either party to post cash collateral for initial margin. Since April 2012, the counterparties, in some cases, have been required to post cash collateral to secure credit exposure above an agreed threshold as a result of changes in power or natural gas prices. At June 30, 2012 and December 31, 2011, \$173 million and \$4 million, respectively, of cash collateral posted by counterparties under master netting agreements were included in accounts payable and accrued liabilities in the consolidated balance sheets. Our credit valuation adjustment on derivative contract assets was \$20 million and \$48 million at June 30, 2012 and December 31, 2011, respectively.

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We monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. The following tables highlight the credit quality and the balance sheet settlement exposures related to these activities:

Credit Rating Equivalent	June 30, 2012					
	Gross Exposure		Net Exposure		Exposure Net	% of Net
	Before		Before			
	Collateral(1)	Collateral(2)	Collateral(3)	of Collateral	Exposure	
(dollars in millions)						
Clearing and Exchange	\$ 677	\$ 300	\$ 300	\$		
Investment Grade:						
Financial institutions	824	786	168	618	67%	
Energy companies	467	259	2	257	28%	
Non-investment Grade:						
Energy companies	15	10	2	8	1%	
No External Ratings:						
Internally-rated investment grade	28	27		27	3%	
Internally-rated non-investment grade	11	11		11	1%	
Total	\$ 2,022	\$ 1,393	\$ 472	\$ 921	100%	

Credit Rating Equivalent	December 31, 2011					
	Gross Exposure		Net Exposure		Exposure Net	% of Net
	Before		Before			
	Collateral(1)	Collateral(2)	Collateral(3)	of Collateral	Exposure	
(dollars in millions)						
Clearing and Exchange	\$ 724	\$ 223	\$ 223	\$		
Investment Grade:						
Financial institutions	860	817		817	78%	
Energy companies	421	195	3	192	18%	
Non-investment Grade:						
Energy companies	13	5	1	4		
No External Ratings:						
Internally-rated investment grade	18	18		18	2%	
Internally-rated non-investment grade	15	15		15	2%	
Total	\$ 2,051	\$ 1,273	\$ 227	\$ 1,046	100%	

- (1) Gross exposure before collateral represents credit exposure, including both realized and unrealized transactions, before (a) applying the terms of master netting agreements with counterparties and (b) netting of transactions with clearing brokers and exchanges. The table excludes amounts related to contracts classified as normal purchases/normal sales and non-derivative contractual commitments that are not recorded at fair value in the consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform. Non-performance could have a material adverse effect on our future results of operations, financial condition and cash flows.
- (2) Net exposure before collateral represents the credit exposure, including both realized and unrealized transactions, after applying the terms of master netting agreements and the netting of transactions with clearing brokers and exchanges.
- (3) Collateral includes cash and letters of credit received from counterparties.

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We had credit exposure to three and two investment grade counterparties at June 30, 2012 and December 31, 2011, respectively, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling \$553 million and \$664 million at June 30, 2012 and December 31, 2011, respectively.

GenOn Credit Risk

Our standard industry contracts contain credit-risk-related contingent features such as ratings-related thresholds whereby we would be required to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. Additionally, some of our contracts contain adequate assurance language, which is

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generally subjective in nature that could require us to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. However, as a result of our current credit rating, we are typically required to post collateral in the normal course of business to offset either substantially or completely the net liability positions, after applying the terms of master netting agreements. At June 30, 2012, the fair value of financial instruments with credit-risk-related contingent features in a net liability position was \$22 million for which we had posted collateral of \$16 million, including cash and letters of credit.

At June 30, 2012 and December 31, 2011, we had \$114 million and \$86 million, respectively, of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit in the consolidated balance sheets.

Fair Values of Other Financial Instruments

The fair values of certain funds on deposit, accounts receivable, notes and other receivables, and accounts payable and accrued liabilities approximate their carrying amounts.

The carrying amounts and fair values of debt are as follows:

	Carrying Amount	Level 1	Level 2(1) (in millions)	Level 3(2)	Total Fair Value
June 30, 2012					
<u>Liabilities:</u>					
Long and short-term debt	\$ 4,277	\$	\$ 3,909	\$ 234	\$ 4,143
December 31, 2011					
<u>Liabilities:</u>					
Long and short-term debt	\$ 4,132	\$	\$ 3,969	\$ 97	\$ 4,066

(1) The fair value of long and short-term debt is estimated using broker quotes for instruments that are publicly traded.

(2) The fair value of long and short-term debt is estimated based on the income approach valuation technique for non-publicly traded debt using current interest rates for similar instruments with equivalent credit quality.

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4. Long-Term Debt

Outstanding debt was as follows:

	Weighted Average Stated Interest Rate(1)	June 30, 2012		December 31, 2011		
		Long-term	Current (in millions, except interest rates)	Long-term	Current	
Facilities, Bonds and Notes:						
GenOn:						
Senior unsecured notes, due 2014	7.625%	\$ 575	\$	7.625%	\$ 575	\$
Senior unsecured notes, due 2017	7.875	725		7.875	725	
Senior secured term loan, due 2017(2)	6.00	681	7	6.00	684	7
Senior unsecured notes, due 2018	9.50	675		9.50	675	
Senior unsecured notes, due 2020	9.875	550		9.875	550	
Unamortized debt discounts		(23)	(2)		(24)	(2)
GenOn Americas Generation:						
Senior unsecured notes, due 2021	8.50	450		8.50	450	
Senior unsecured notes, due 2031	9.125	400		9.125	400	
Unamortized debt discounts		(2)			(2)	
GenOn Marsh Landing:						
Senior secured term loan, due 2017	2.75	79		2.76	33	
Senior secured term loan, due 2023	3.00	176		3.01	74	
Other:						
Capital leases, due 2015	7.375-8.19	11	5	7.375-8.19	14	5
Adjustment to fair value of debt(3)		(30)			(32)	
Total		\$ 4,267	\$ 10		\$ 4,122	\$ 10

(1) The weighted average stated interest rates are at June 30, 2012 and December 31, 2011, respectively.

(2) The debt balance on the term loan facility is recorded at GenOn Americas, a direct subsidiary of GenOn Energy Holdings, because GenOn Americas is a co-borrower.

(3) Debt assumed in the Mirant/RRI Merger was adjusted to fair value on the Mirant/RRI Merger date. The adjustment is amortized to interest expense over various years through 2017.

GenOn Credit Facilities

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At June 30, 2012, outstanding letters of credit were \$284 million and availability of borrowings under the revolving credit facility was \$504 million.

5. Pension and Other Postretirement Benefit Plans

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The components of the net periodic benefit cost are shown below:

	Pension Plans				Other Postretirement Benefit Plans			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
	(in millions)							
Service cost	\$ 3	\$ 3	\$ 6	\$ 6	\$ 1	\$ 1	\$ 1	\$ 1
Interest cost	6	6	12	12	1	1	2	2
Expected return on plan assets	(8)	(7)	(15)	(15)				
Net amortization(1)	2	1	4	2	(1)	(1)	(2)	(2)
Net periodic benefit cost	\$ 3	\$ 3	\$ 7	\$ 5	\$ 1	\$ 1	\$ 1	\$ 1

(1) Net amortization amounts include actuarial gains/losses and prior service cost/credit.

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Compensation expense for the stock-based incentive plan was:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Stock-based incentive plan compensation expense (pre-tax)(1)	\$ 6	\$ 5	\$ 9	\$ 8

(1) No tax benefits related to stock-based compensation were realized during the three and six months ended June 30, 2012 and 2011 because of our NOL carryforwards.

During February 2012, we granted long-term incentive awards as follows:

Award Vehicle	Awards Granted	Vesting Period
Time-based Restricted Stock Units	2,821,302	Vest ratably each year over a three-year period; common stock settled
Performance-based Restricted Stock Units	2,586,482	Linked to the achievement of the 2012 short-term incentive plan performance goals, with performance measured at the end of the first year; vest ratably each year over three-year period; common stock settled
Stock Options	5,897,990	Vest ratably each year over three-year period

Vesting in Connection with the NRG Merger. All outstanding stock options (other than options granted in 2012) will immediately vest (to the extent not already fully vested) and all outstanding stock options will generally convert upon completion of the NRG Merger into stock options with respect to NRG common stock, after giving effect to the exchange ratio. In addition, all outstanding restricted stock units (other than restricted stock units granted in 2012) will immediately vest (to the extent not already fully vested) and all outstanding restricted stock units will be exchanged for the NRG Merger consideration. All outstanding stock options and restricted stock units granted in 2012 will vest (to the extent not already fully vested) at the holder's termination date if the termination is as a result of the NRG Merger and within two years of the closing date. See note 11.

7. Earnings Per Share

We calculate basic EPS by dividing income/loss available to stockholders by the weighted average number of common shares outstanding. Diluted EPS gives effect to dilutive potential common shares, including unvested restricted stock units and stock options.

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The following table shows the computation of basic and diluted EPS:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions, except per share data)			
Net loss	\$ (228)	\$ (138)	\$ (260)	\$ (249)
Basic and diluted shares				
Weighted average shares outstanding basic	774	772	774	771
Effect of dilutive securities(1)				
Weighted average shares outstanding diluted	774	772	774	771
Basic and Diluted EPS				
Basic EPS	\$ (0.30)	\$ (0.18)	\$ (0.34)	\$ (0.32)
Diluted EPS	\$ (0.30)	\$ (0.18)	\$ (0.34)	\$ (0.32)

(1) As we incurred a net loss for the three and six months ended June 30, 2012 and 2011, diluted loss per share is calculated the same as basic loss per share.

The weighted average number of securities that could potentially dilute basic EPS in the future that were not included in the computation of diluted EPS because to do so would have been antidilutive was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Stock options	19	19	18	19
Restricted stock units	9	4	7	4
Total number of antidilutive shares	28	23	25	23

8. Accumulated Other Comprehensive Loss

The component balances of accumulated other comprehensive loss, included in the consolidated balance sheets, are as follows:

	June 30, 2012	December 31, 2011
	(in millions)	
Pension and other postretirement benefits actuarial losses, net	\$ (138)	\$ (142)
Pension and other postretirement benefits prior service credit, net	5	7
Cash flow hedges interest rate swaps	(46)	(34)

Other, net				(1)
Accumulated other comprehensive loss	\$	(179)	\$	(170)

9. Segment Reporting

We have five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. The segments are determined based on how the business is managed and align with the information provided to the chief operating decision maker for purposes of assessing performance and allocating resources. Generally, our segments are engaged in the sale of electricity, capacity, and ancillary and other energy services from their generating facilities in hour-ahead, day-ahead and forward markets in bilateral and ISO markets. We also engage in proprietary trading, fuel oil management and natural gas transportation and storage activities. Operating

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revenues consist of (a) power generation revenues, (b) contracted and capacity revenues, (c) power hedging revenues and (d) fuel sales and proprietary trading revenues.

The Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia with total net generating capacity of 6,341 MW. The Western PJM/MISO segment consists of 23 generating facilities located in Illinois, Ohio and Pennsylvania with total net generating capacity of 7,086 MW. The total net generating capacity for the Western PJM/MISO segment excludes certain units at Elrama and Niles (397 MW), which were deactivated in June 2012. The California segment consists of seven generating facilities located in California, with total net generating capacity of 5,391 MW and includes business development and construction activities for GenOn Marsh Landing. The total net generating capacity for California excludes the Potrero generating facility (362 MW), which was shut down in February 2011. See note 2 for a discussion of generating facilities in the Eastern PJM, Western PJM/MISO and California segments that we expect to retire, mothball or place in long-term protective layup between October 2012 and May 2015. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of seven generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas with total net generating capacity of 3,852 MW. We sold our Indian River generating facility (586 MW), which was included in the Other Operations segment, in January 2012. A tolling agreement on the Vandolah facility (630 MW), which entitled us to purchase and dispatch electric generating capacity, expired in May 2012. Other Operations also includes unallocated overhead expenses and other activity that cannot be identified specifically with another segment. All revenues are generated and long-lived assets are located within the United States.

The measure of profit or loss for our reportable segments is operating income/loss. This measure represents the lowest level of information that is provided to the chief operating decision maker for our reportable segments.

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Three Months Ended							
June 30, 2012:							
Operating revenues(1)	\$ 221	\$ 180	\$ 31	\$ 45	\$ 44	\$	\$ 521
Cost of fuel, electricity and other products(2)	154	91	1	34	26		306
Gross margin (excluding depreciation and amortization)	67	89	30	11	18		215
Operating Expenses:							
Operations and maintenance	85(3)	114	38	1	26		264
Depreciation and amortization	34	31	12		13		90
Total operating expenses	119	145	50	1	39		354
Operating income (loss)	\$ (52)	\$ (56)	\$ (20)	\$ 10	\$ (21)	\$	\$ (139)

(1) Includes unrealized gains (losses) of \$(66) million, \$(30) million, \$(4) million, \$10 million and \$(12) million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized (gains) losses of \$47 million, \$1 million, \$1 million and \$(9) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(3) Includes \$31 million of income related to the reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria.

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	Western		Energy Marketing		Other Operations		Eliminations		Total	
	Eastern PJM	PJM/MISO	California	(in millions)						
Six Months Ended June 30, 2012:										
Operating revenues(1)	\$ 552	\$ 485	\$ 62	\$ 51	\$ 92	\$	\$	\$	\$	1,242
Cost of fuel, electricity and other products(2)	269	245	2	15	53					584
Gross margin (excluding depreciation and amortization)	283	240	60	36	39					658
Operating Expenses:										
Operations and maintenance(3)	191(4)	244	83	3	51					572
Depreciation and amortization	67	61	23		27					178
Gain on sales of assets, net		(1)			(7)					(8)
Total operating expenses	258	304	106	3	71					742
Operating income (loss)	\$ 25	\$ (64)	\$ (46)	\$ 33	\$ (32)	\$	\$	\$	\$	(84)
Total assets at June 30, 2012	\$ 4,706	\$ 3,407	\$ 1,059	\$ 2,115	\$ 3,418(5)	\$	(2,687)	\$	\$	12,018

- (1) Includes unrealized gains (losses) of \$1 million, \$35 million, \$(1) million, \$14 million and \$(8) million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.
- (2) Includes unrealized (gains) losses of \$72 million, \$18 million, \$2 million and \$(9) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.
- (3) Includes costs to deactivate generating facilities of \$4 million, \$30 million and \$2 million for Eastern PJM, Western PJM/MISO and California, respectively.
- (4) Includes \$31 million of income related to the reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria.
- (5) Includes our equity method investment in Sabine Cogen, LP of \$20 million.

	Western		Energy Marketing		Other Operations		Eliminations		Total	
	Eastern PJM	PJM/MISO	California	(in millions)						
Three Months Ended June 30, 2011:										
Operating revenues(1)	\$ 300	\$ 293	\$ 36	\$ 119	\$ 64	\$	\$	\$	\$	812
Cost of fuel, electricity and other products(2)	116	157	1	85	31					390
Gross margin (excluding depreciation and	184	136	35	34	33					422

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amortization)

Operating Expenses:

Operations and maintenance	146 ⁽³⁾	149	39	(2)	40 ⁽⁴⁾	372
Depreciation and amortization	34	31	11	1	13	90
Loss on sales of assets, net					2	2
Total operating expenses	180	180	50	(1)	55	464
Operating income (loss)	\$ 4	\$ (44)	\$ (15)	\$ 35	\$ (22)	\$ (42)

(1) Includes unrealized gains (losses) of \$(27) million, \$(22) million, \$(1) million, \$13 million and \$1 million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized (gains) losses of \$(15) million, \$(5) million and \$2 million for Eastern PJM, Western PJM/MISO and Energy Marketing, respectively.

(3) Includes \$30 million of expense for large scale remediation and settlement costs.

(4) Includes \$14 million of Mirant/RRI Merger-related costs.

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	Eastern PJM		Western PJM/MISO		California	Energy Marketing (in millions)	Other Operations	Eliminations	Total						
Six Months Ended															
June 30, 2011:															
Operating revenues(1)	\$	616	\$	617	\$	72	\$	204	\$	117	\$		\$	1,626	
Cost of fuel, electricity and other products(2)		254		320		3		151		63				791	
Gross margin (excluding depreciation and amortization)		362		297		69		53		54				835	
Operating Expenses:															
Operations and maintenance		252(3)		260		78		2		85(4)				677	
Depreciation and amortization		67		59		21		1		28				176	
Loss on sales of assets, net										1				1	
Total operating expenses		319		319		99		3		114				854	
Operating income (loss)	\$	43	\$	(22)	\$	(30)	\$	50	\$	(60)	\$			(19)	
Total assets at December 31, 2011	\$	4,732	\$	3,343	\$	856	\$	2,173	\$	3,662(5)	\$		(2,497)	\$	12,269

- (1) Includes unrealized losses of \$78 million, \$35 million, \$1 million, \$11 million and \$10 million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.
- (2) Includes unrealized gains of \$27 million, \$9 million and \$2 million for Eastern PJM, Western PJM/MISO and Other Operations, respectively.
- (3) Includes \$30 million of expense for large scale remediation and settlement costs.
- (4) Includes \$37 million of Mirant/RRI Merger-related costs.
- (5) Includes our equity method investment in Sabine Cogen, LP of \$22 million.

	Three Months Ended June 30,			Six Months Ended June 30,				
	2012	2011	2011	2012	2011	2011		
	(in millions)							
Operating loss for all segments	\$	(139)	\$	(42)	\$	(84)	\$	(19)
Interest expense		(85)		(96)		(174)		(205)
Other, net						2		(22)
Loss before income taxes	\$	(224)	\$	(138)	\$	(256)	\$	(246)

10. Litigation and Other Contingencies

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We are involved in a number of legal proceedings. In certain cases, plaintiffs seek to recover large or unspecified damages, and some matters may be unresolved for several years. We cannot currently determine the outcome of the proceedings described below or estimate the reasonable amount or range of potential losses, if any, and therefore have not made any provision for such matters unless specifically noted below.

Scrubber Contract Litigation

In January 2011, Stone & Webster, the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown generating facilities, filed three suits against us in the United States District Court for the District of Maryland. Stone & Webster claimed that it had not been paid in accordance with the terms of the EPC agreements for the scrubber projects and sought liens against the properties, which the court granted. We disputed Stone & Webster's allegations and in February 2011 filed a related action against Stone & Webster in the United States District Court for the Southern District of New York. The proceedings in Maryland were stayed pending resolution of the proceeding in New York.

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In June 2012, we executed a settlement agreement with Stone & Webster. Under the terms of the settlement agreement GenOn agreed to pay Stone & Webster \$107.1 million in settlement of all outstanding invoices and amounts claimed to be owed by Stone & Webster in connection with the construction of the scrubber projects. As part of the settlement, Stone & Webster released the \$165.6 million in interlocutory liens that had been filed by Stone & Webster on the Chalk Point, Dickerson and Morgantown generating facilities. As a result of the release of the liens, GenOn Mid-Atlantic released the \$165.6 million in reserved cash during June 2012 (previously included as funds on deposit in the consolidated balance sheets). In connection with the settlement agreement, we dismissed our dispute filed in the United States District Court for the Southern District of New York.

We incurred \$1.7 billion in capital expenditures from 2007 to 2012 for compliance with the Maryland Healthy Air Act.

Pending Natural Gas Litigation

We are party to five lawsuits, several of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada and Wisconsin. These lawsuits were filed in the aftermath of the California energy crisis and the resulting FERC investigations and relate to alleged conduct to increase natural gas prices in violation of antitrust and similar laws. The lawsuits seek treble or punitive damages, restitution and/or expenses. The lawsuits also name a number of unaffiliated energy companies as parties. In July 2011, the judge in the United States District Court for the District of Nevada handling four of the five cases granted the defendants' motion for summary judgment dismissing all claims against us in those cases. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. The fifth case is pending in the State of Nevada Supreme Court on plaintiff's appeal of the dismissal of all its claims by the Eighth Judicial District Court for Clark County, Nevada. We have agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

Bowline Property Tax Dispute

In 2011, 2010 and 2009 we filed suit against the town of Haverstraw, New York to challenge the property tax assessment of the Bowline generating facility for each respective tax year. Although the assessments for the 2011 and 2010 tax years were reduced significantly from the assessment received in 2009, they continue to exceed significantly the estimated fair value of the generating facility. The tax litigation for all three years has been combined for trial purposes. While we are unable to predict the outcome of this litigation, if we are successful we expect to receive a refund for each of the years under protest.

Environmental Matters

Global Warming. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a suit in the United States District Court for the Northern District of California against GenOn and 23 other electric generating and oil and gas companies. The lawsuit seeks damages of up to \$400 million for the cost of relocating the village allegedly because of global warming caused by the greenhouse gas emissions of the defendants. In late 2009, the District Court ordered that the case be dismissed and the plaintiffs appealed. Although we think claims such as this lack legal merit, it is possible that this trend of climate change litigation may continue.

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New Source Review Matters. The EPA and various states are investigating compliance of coal-fueled electric generating facilities with the pre-construction permitting requirements of the Clean Air Act known as new source review. Since 2000, the EPA has made information requests concerning the Avon Lake, Chalk Point, Cheswick, Conemaugh, Dickerson, Elrama, Keystone, Morgantown, New Castle, Niles, Portland, Potomac River, Shawville and Titus generating facilities. We are corresponding or have corresponded with the EPA regarding all of these requests. The EPA agreed to share information relating to its investigations with state environmental agencies. In January 2009, we received an NOV from the EPA alleging that past work at our Shawville, Portland and Keystone generating facilities violated regulations regarding new source review. In June 2011, we received an NOV from the EPA alleging that past work at our Niles and Avon Lake generating facilities violated regulations regarding new source review.

In December 2007, the NJDEP filed suit against us in the United States District Court for the Eastern District of Pennsylvania, alleging that new source review violations occurred at the Portland generating facility. The suit

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seeks installation of best available control technologies for each pollutant, to enjoin us from operating the generating facility if it is not in compliance with the Clean Air Act and civil penalties. The suit also names three past owners of the plant as defendants. In March 2009, the Connecticut Department of Environmental Protection became an intervening party to the suit.

We think that the work listed by the EPA and the work subject to the NJDEP suit were conducted in compliance with applicable regulations. However, any final finding that we violated the new source review requirements could result in fines, penalties or significant capital expenditures associated with the implementation of emissions reductions on an accelerated basis. Most of these work projects were undertaken before our ownership or lease of those facilities.

In addition, the NJDEP filed two administrative petitions with the EPA in 2010 alleging that our Portland generating facility's emissions were significantly contributing to nonattainment and/or interfering with the maintenance of certain NAAQS in New Jersey. In November 2011, the EPA published a final rule in response to one of the petitions that will require us to reduce our maximum allowable SO₂ emissions from the two coal-fired units by about 60% starting in January 2013 and by about 80% starting in January 2015. In January 2012, we challenged the rule in the United States Court of Appeals for the Third Circuit. In 2013 and 2014, we have several compliance options that include using lower sulfur coals (although this may at times reduce how much we are able to generate) or running just one unit at a time. Starting in January 2015, these units will be subject to more stringent rate limits, which will require either material capital expenditures and higher operating costs or the retirement of these two units. See note 2 for a discussion of the Portland coal-fired units that we expect to deactivate in 2015.

Cheswick Class Action Complaint. In April 2012, a putative class action lawsuit was filed against us in the Court of Common Pleas of Allegheny County, Pennsylvania alleging that emissions from our Cheswick generating facility have damaged the property of neighboring residents. We dispute these allegations. Plaintiffs have brought nuisance, negligence, trespass and strict liability claims seeking both damages and injunctive relief. Plaintiffs seek to certify a class that consists of people who own property or live within one mile of our plant. In July 2012, we removed the lawsuit to the United States District Court for the Western District of Pennsylvania.

Cheswick Monarch Mine NOV. In 2008, the PADEP issued an NOV related to the Monarch mine located near our Cheswick generating facility. It has not been mined for many years. We use it for disposal of low-volume wastewater from the Cheswick generating facility and for disposal of leachate collected from ash disposal facilities. The NOV addresses the alleged requirement to maintain a minimum pumping volume from the mine. The PADEP indicated it may assess a civil penalty in excess of \$100,000. We contest the allegations in the NOV and have not agreed to such penalty. We are currently planning capital expenditures in connection with wastewater from Cheswick and leachate from ash disposal facilities.

Conemaugh Alleged Clean Streams Law Violations. The PADEP has alleged that several violations of the Pennsylvania Clean Streams Law occurred at the Conemaugh generating facility. We have an agreement in principle with the PADEP that we expect will resolve these issues and obligate us to pay a civil penalty of \$500,000. We are responsible for 16.45% of this amount.

Maryland Fly Ash Facilities. We have three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. We dispose of fly ash from our Morgantown and Chalk Point generating facilities at Brandywine. We dispose of fly ash from our Dickerson generating facility at Westland. We no longer dispose of fly ash at the Faulkner facility. As described below, the MDE has sued us regarding Faulkner and Brandywine and threatened to sue regarding Westland. The MDE also had threatened not to renew the water discharge permits for all three facilities.

Faulkner Litigation. In May 2008, the MDE sued us in the Circuit Court for Charles County, Maryland alleging violations of Maryland's water pollution laws at Faulkner. The MDE contended that the operation of Faulkner had resulted in the discharge of pollutants that exceeded Maryland's water quality criteria and without the appropriate NPDES permit. The MDE also alleged that we failed to perform certain sampling and reporting required under an applicable NPDES permit. The MDE complaint requested that the court (a) prohibit continuation of the alleged unpermitted discharges, (b) require us to cease from further disposal of any coal combustion byproducts at Faulkner and close and cap the existing disposal cells and (c) assess civil penalties. In July 2008, we

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filed a motion to dismiss the complaint, arguing that the discharges are permitted by a December 2000 Consent Order. In January 2011, the MDE dismissed without prejudice its complaint and informed us that it intended to file a similar lawsuit in federal court. In May 2011, the MDE filed a complaint against us in the United States District Court for the District of Maryland alleging violations at Faulkner of the Clean Water Act and Maryland's Water Pollution Control Law. The MDE contends that (a) certain of our water discharges are not authorized by our existing permit and (b) operation of the Faulkner facility has resulted in discharges of pollutants that violate water quality criteria. The complaint asks the court to, among other things, (a) enjoin further disposal of coal ash; (b) enjoin discharges that are not authorized by our existing permit; (c) require numerous technical studies; (d) impose civil penalties and (e) award MDE attorneys' fees. We dispute the allegations.

Brandywine Litigation. In April 2010, the MDE filed a complaint against us in the United States District Court for the District of Maryland asserting violations at Brandywine of the Clean Water Act and Maryland's Water Pollution Control Law. The MDE contends that the operation of Brandywine has resulted in discharges of pollutants that violate Maryland's water quality criteria. The complaint requests that the court, among other things, (a) enjoin further disposal of coal combustion waste at Brandywine, (b) require us to close and cap the existing open disposal cells within one year, (c) impose civil penalties and (d) award MDE attorneys' fees. We dispute the allegations. In September 2010, four environmental advocacy groups became intervening parties in the proceeding.

Threatened Westland Litigation. In January 2011, the MDE informed us that it intended to sue us for alleged violations at Westland of Maryland's water pollution laws. To date, MDE has not sued us regarding our ash disposal.

Permit Renewals. In March 2011, the MDE tentatively determined to deny our application for the renewal of the water discharge permit for Brandywine, which could result in a significant increase in operating expenses for our Chalk Point and Morgantown generating facilities. The MDE also had indicated that it was planning to deny our applications for the renewal of the water discharge permits for Faulkner and Westland. Denial of the renewal of the water discharge permit for the latter facility could result in a significant increase in operating expenses for our Dickerson generating facility.

Stay and Settlement Discussions. In June 2011, the MDE agreed to stay the litigation related to Faulkner and Brandywine while we pursued settlement of allegations related to the three Maryland ash facilities. MDE also agreed not to pursue its tentative denial of our application to renew our water discharge permit at Brandywine and agreed not to act on our renewal applications for Faulkner or Westland while we were discussing settlement. As a condition to obtaining the stay, we agreed in principle to pay a civil penalty of \$2.5 million to the MDE if we reach a comprehensive settlement regarding all of the allegations related to the three Maryland ash facilities. We accrued \$1.9 million during 2011 and \$0.6 million during the three months ended June 30, 2012 for a total of \$2.5 million. We also developed a technical solution, which includes installing synthetic caps on the closed cells of each of the three ash facilities. During 2011, we accrued \$47 million for the estimated cost of the technical solution. We have concluded our settlement discussions with the MDE. We expect to sign a consent decree settling these matters in August 2012. At this time, we cannot reasonably estimate the upper range of our obligations for remediating the sites for the following reasons: (a) we have not finished assessing each site including identifying the full impacts to both ground and surface water and the impacts to the surrounding habitat; (b) we have not finalized with the MDE the standards to which we must remediate; and (c) we have not identified the technologies required, if any, to meet the mandated remediation standards at each site nor the timing of the design and installation of such technologies.

Brandywine Storm Damage and Ash Recovery. As a result of Hurricane Irene and Tropical Storm Lee in August and September 2011, an estimated 8,800 cubic yards of coal fly ash stored in one of the cells at the Brandywine ash disposal site flowed onto 18 acres of private property adjacent to the site. During 2011, we accrued \$10 million for the estimated costs to remove and clean up the ash. We have removed the released ash from the private property and are finalizing the remaining clean-up activities with the MDE and the property owners. Nearing completion, we have been able to define more narrowly our costs and have therefore adjusted our estimate and reversed \$4 million during the three months

ended June 30, 2012. We are pursuing recovery under our insurance policies for our costs to remove and clean up the ash.

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Brandywine Filling of Wetlands. While expanding and installing a liner at the Brandywine ash disposal site, we inadvertently filled wetlands without having all of the requisite permits. The MDE also has alleged that we violated the notice requirements of our sediment and erosion control plan. In March 2012, the MDE informed us that it was considering seeking a fine in excess of \$100,000 to settle the storm damage and the filling of wetlands without requisite permits. In July 2012, the MDE filed a complaint in the Circuit Court for Prince George's County, Maryland for civil penalties and injunctive relief related to this matter. We are currently in settlement discussions with the MDE but have agreed in principle to settle this matter by paying a fine of \$300,000.

Ash Disposal Facility Closures. We are responsible for environmental costs related to the future closures of several ash disposal facilities. We have accrued the estimated discounted costs (\$40 million and \$38 million at June 30, 2012 and December 31, 2011, respectively) associated with these environmental liabilities as part of the asset retirement obligations. These amounts are exclusive of the \$47 million accrual for the technical solution for the three ash facilities in Maryland discussed above.

Remediation Obligations. We are responsible under the Industrial Site Recovery Act for environmental costs related to site contamination investigations and remediation requirements at four generating facilities in New Jersey. We have accrued the estimated long-term liability for the remediation costs of \$6 million at June 30, 2012 and December 31, 2011.

Chapter 11 Proceedings

In July 2003, and various dates thereafter, the Mirant Debtors filed voluntary petitions in the Bankruptcy Court for relief under Chapter 11 of the United States Bankruptcy Code. GenOn Energy Holdings and most of the other Mirant Debtors emerged from bankruptcy on January 3, 2006, when the Plan became effective. The remaining Mirant Debtors emerged from bankruptcy on various dates in 2007. Approximately 461,000 of the shares of GenOn Energy Holdings common stock to be distributed under the Plan have not yet been distributed and have been reserved for distribution with respect to claims disputed by the Mirant Debtors that have not been resolved. Upon the Mirant/RRI Merger, those reserved shares converted into a reserve for approximately 1.3 million shares of GenOn common stock. Under the terms of the Plan, upon the resolution of such a disputed claim, the claimant will receive the same pro rata distributions of common stock, cash, or both as previously allowed claims, regardless of the price at which the common stock is trading at the time the claim is resolved. If the aggregate amount of any such payouts results in the number of reserved shares being insufficient, additional shares of common stock may be issued to address the shortfall.

Actions Pursued by MC Asset Recovery

Under the Plan, the rights to certain actions filed by GenOn Energy Holdings and some of its subsidiaries against third parties were transferred to MC Asset Recovery, a wholly-owned subsidiary of GenOn Energy Holdings. MC Asset Recovery is now governed by a manager who is independent of us. Under the Plan, any cash recoveries obtained by MC Asset Recovery from the actions transferred to it, net of fees and costs incurred in prosecuting the actions, are to be paid to the unsecured creditors of GenOn Energy Holdings in the Chapter 11 proceedings and the holders of the equity interests in GenOn Energy Holdings immediately prior to the effective date of the Plan except where such a recovery results in an allowed claim in the bankruptcy proceedings, as described below. MC Asset Recovery is a disregarded entity for income tax purposes, and GenOn Energy Holdings is responsible for income taxes related to its operations. The Plan provides that GenOn Energy Holdings may not reduce payments to be made to unsecured creditors and former holders of equity interests from recoveries obtained by MC Asset Recovery for the taxes owed by GenOn Energy Holdings, if any, on any net recoveries up to \$175 million. If the aggregate recoveries exceed \$175 million net of costs, then GenOn Energy Holdings may reduce the payments by the amount of any taxes it will owe or NOLs utilized with respect to taxable income resulting from the amount in excess of \$175 million.

The Plan and the MC Asset Recovery Limited Liability Company Agreement also obligate GenOn Energy Holdings to make contributions to MC Asset Recovery as necessary to pay professional fees and certain other costs. In June 2008, GenOn Energy Holdings and MC Asset Recovery, with the approval of the Bankruptcy Court, agreed to limit the total amount of funding to be provided by GenOn Energy Holdings to MC Asset Recovery to \$68 million, and the amount of such funding obligation not already incurred by GenOn Energy Holdings at that time

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was fully accrued. GenOn Energy Holdings was entitled to be repaid the amounts it funded from any recoveries obtained by MC Asset Recovery before any distribution was made from such recoveries to the unsecured creditors of GenOn Energy Holdings and the former holders of equity interests.

In March 2009, Southern Company and MC Asset Recovery entered into a settlement agreement resolving claims asserted by MC Asset Recovery in a suit that was pending in the United States District Court for the Northern District of Georgia. Southern Company paid \$202 million to MC Asset Recovery in settlement of all claims asserted in the litigation. MC Asset Recovery used a portion of that payment to pay fees owed to the managers of MC Asset Recovery and other expenses of MC Asset Recovery not previously funded by GenOn Energy Holdings, and it retained \$47 million from that payment to fund future expenses and to apply against unpaid expenditures. MC Asset Recovery distributed the remaining \$155 million to GenOn Energy Holdings. In accordance with the Plan, GenOn Energy Holdings retained approximately \$52 million of that distribution as reimbursement for the funds it had provided to MC Asset Recovery and costs it incurred related to MC Asset Recovery that had not been previously reimbursed. GenOn Energy Holdings recognized the \$52 million as a reduction of operations and maintenance expense during 2009. Pursuant to MC Asset Recovery's Limited Liability Company Agreement and an order of the Bankruptcy Court dated October 31, 2006, GenOn Energy Holdings distributed \$2 million to the managers of MC Asset Recovery. In September 2009, the remaining approximately \$101 million of the amount recovered by MC Asset Recovery was distributed pursuant to the terms of the Plan. Following these distributions, GenOn Energy Holdings has no further obligation to provide funding to MC Asset Recovery. As a result, GenOn Energy Holdings reversed its remaining accrual of \$10 million of funding obligations as a reduction in operations and maintenance expense for 2009. GenOn does not expect to owe any taxes related to the MC Asset Recovery settlement with Southern Company.

Based on a stipulation entered by the Bankruptcy Court in December 2011 and pursuant to the terms of the Plan and the MC Asset Recovery Limited Liability Company Agreement, during March 2012, GenOn Energy Holdings distributed \$26 million of the \$47 million in funds that had been previously retained by MC Asset Recovery.

One of the two remaining actions transferred to MC Asset Recovery seeks to recover damages from Commerzbank AG and various other banks (the Commerzbank Defendants) for alleged fraudulent transfers that occurred prior to the filing of GenOn Energy Holdings' bankruptcy proceedings. In its amended complaint, MC Asset Recovery alleges that the Commerzbank Defendants in 2002 and 2003 received payments totaling approximately 153 million Euros directly or indirectly from GenOn Energy Holdings under a guarantee provided by GenOn Energy Holdings in 2001 of certain equipment purchase obligations. MC Asset Recovery alleges that at the time GenOn Energy Holdings provided the guarantee and made the payments to the Commerzbank Defendants, GenOn Energy Holdings was insolvent and did not receive fair value for those transactions. In December 2010, the United States District Court for the Northern District of Texas dismissed MC Asset Recovery's complaint against the Commerzbank Defendants. In January 2011, MC Asset Recovery appealed the United States District Court's dismissal of its complaint against the Commerzbank Defendants to the United States Court of Appeals for the Fifth Circuit. In March 2012, the United States Court of Appeals for the Fifth Circuit reversed the United States District Court's dismissal and reinstated MC Asset Recovery's amended complaint against the Commerzbank Defendants. If MC Asset Recovery succeeds in obtaining any recoveries on these avoidance claims, the Commerzbank Defendants have asserted that they will seek to file claims in GenOn Energy Holdings' bankruptcy proceedings for the amount of those recoveries. GenOn Energy Holdings would vigorously contest the allowance of any such claims on the ground that, among other things, the recovery of such amounts by MC Asset Recovery does not reinstate any enforceable pre-petition obligation that could give rise to a claim. If such a claim were to be allowed by the Bankruptcy Court as a result of a recovery by MC Asset Recovery, then the Plan provides that the Commerzbank Defendants are entitled to the same distributions as previously made under the Plan to holders of similar allowed claims. Holders of previously allowed claims similar in nature to the claims that the Commerzbank Defendants would seek to assert have received 43.87 shares of GenOn Energy Holdings common stock for each \$1,000 of claim allowed by the Bankruptcy Court. If the Commerzbank Defendants were to receive an allowed claim as a result of a recovery by MC Asset Recovery on its claims against them, the order entered by the Bankruptcy Court in December 2005, confirming the Plan provides that GenOn Energy Holdings would retain from the net amount recovered by MC Asset Recovery an amount equal to the dollar amount of the resulting allowed claim rather than distribute such amount to the unsecured creditors and former equity holders as described above.

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Texas Franchise Audit

In 2008 and 2009, the State of Texas, as a result of its audit, issued franchise tax assessments against us indicating an underpayment of franchise tax of \$71 million (including interest and penalties through June 30, 2012 of \$28 million). These assessments are related primarily to a claim by Texas that would change the sourcing of intercompany receipts for the years 2000 through 2006, thereby increasing the amount of tax due to Texas. We disagree with most of the State's assessment and its determination of the related tax liability. Given the disagreement with the State's position, we have accrued a portion of the liability but have protested the entire assessment and are currently in the administrative appeals process. If we do not fully resolve or come to satisfactory settlement of the protested issues, then we could pay up to the entire amount of the assessed tax, penalties and interest. We intend to defend fully our position in the administrative appeals process and if such defense requires litigation, would be required to pay the full assessment and sue for refund.

NRG Merger Litigation

In July 2012, we, the members of our board of directors, NRG, and Plus Merger Corporation (a wholly-owned subsidiary of NRG) were named defendants in three purported class action lawsuits filed in the District Court of Harris County, Texas, one purported class action lawsuit filed in the United States District Court for the Southern District of Texas, and five purported class action lawsuits filed in the Court of Chancery of the State of Delaware, in each case, brought on behalf of proposed classes consisting of holders of our common stock, excluding defendants and their affiliates. The complaints allege, among other things, that the NRG Merger Agreement was the product of breaches of fiduciary duties by the individual defendants, in that it allegedly does not maximize the value for our stockholders, and that the other defendants aided and abetted the individual defendants' breaches of fiduciary duties. The complaints seek, among other things, (a) a declaration that the NRG Merger Agreement was entered into in breach of the defendants' duties, (b) to enjoin defendants from consummating the NRG Merger, (c) directing the defendants to exercise their duties to obtain a transaction which is in the best interests of our stockholders, (d) granting the class members any benefits allegedly improperly received by the defendants, and/or (e) a rescission of the NRG Merger if it is consummated. We think that the allegations of the complaints are without merit and that we have substantial meritorious defenses to the claims made in these actions. See note 11.

11. Subsequent Event

On July 20, 2012, we entered into the NRG Merger Agreement with NRG Energy, Inc. and a direct wholly-owned subsidiary of NRG. Upon the terms and subject to the conditions set forth in the NRG Merger Agreement, which has been approved by the boards of directors of GenOn and NRG, a wholly-owned subsidiary of NRG will merge with and into GenOn, with GenOn continuing as the surviving corporation and a wholly owned subsidiary of NRG.

Upon closing of the NRG Merger, each issued and outstanding share of our common stock will automatically convert into the right to receive 0.1216 shares of common stock of NRG based on the exchange ratio. All outstanding stock options (other than options granted in 2012) will immediately vest and all outstanding stock options will generally convert upon completion of the NRG Merger into stock options with respect to NRG common stock, after giving effect to the exchange ratio. In addition, all outstanding restricted stock units (other than restricted stock units granted in 2012) will immediately vest and all outstanding restricted stock units will be exchanged for the NRG Merger consideration. All outstanding stock options and restricted stock units granted in 2012 will vest at the holder's termination date if the termination is as a result of the NRG Merger and within two years of the closing date. See note 6.

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The NRG Merger is intended to qualify as a tax-free reorganization under the IRC, as amended, so that none of GenOn, NRG or any of our stockholders generally will recognize any gain or loss in the transaction, except that our stockholders will recognize gain with respect to cash received in lieu of fractional shares of NRG common stock.

Completion of the NRG Merger is contingent upon, among other things, (a) approvals by NRG stockholders of the issuance of NRG common stock in the NRG Merger and the approval and adoption of the amendment to NRG's certificate of incorporation to allow the size of NRG's board of directors to be increased to 16 in connection with the closing of the NRG Merger, (b) adoption of the NRG Merger Agreement by our stockholders,

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(c) effectiveness of an NRG registration statement on Form S-4 and approval of the New York Stock Exchange listing for the NRG common stock to be issued in the NRG Merger, (d) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and (e) receipt of all required regulatory approvals, including approvals from the FERC, the Public Utility Commission of Texas, and the New York Public Service Commission (or the determination by the Public Utility Commission of Texas and the New York Public Service Commission that no approval is required).

We and NRG are also subject to restrictions on our respective ability to solicit alternative acquisition proposals and to provide information to, and engage in discussion with, third parties, except under limited circumstances to permit our or NRG's board of directors to comply with their respective fiduciary duties. The NRG Merger Agreement contains termination rights for both us and NRG and further provides that, upon termination of the NRG Merger Agreement under specified circumstances, NRG may be required to pay a termination fee of \$120 million to us and we may be required to pay NRG a termination fee of \$60 million.

In addition, at NRG's request and upon the terms and subject to the conditions of the NRG Merger Agreement, we will commence a change of control tender offer for each series of our outstanding notes due 2014, 2017, 2018 and 2020, conditioned on the completion of the NRG Merger (the Change in Control Offers). In addition, upon the terms and subject to the conditions of the NRG Merger Agreement, NRG may, at its election following consultation with us, commence a tender offer for cash or an exchange offer for securities for all or any portion of our outstanding notes due 2014, 2017, 2018 and 2020, conditioned on the completion of the NRG Merger (together with the Change in Control Offers, the Debt Offers). NRG may, upon the terms and subject to the conditions of the NRG Merger Agreement, elect to also undertake a consent solicitation to alter the terms of any of our remaining notes due 2014, 2017, 2018 and 2020 outstanding after such tender or exchange offers. NRG intends to fund the Debt Offers and the related fees, commissions and expenses with a combination of funds available at each company (including funds available under existing credit facilities) and, to the extent necessary, new financing for which NRG has obtained commitment letters from Credit Suisse Securities (USA) LLC and Morgan Stanley Senior Funding, Inc. to fund up to \$1.6 billion under a new senior secured term loan facility, to the extent such funds are necessary to consummate the Debt Offers. NRG has agreed to use reasonable best efforts to obtain the financing, to the extent required, and we have agreed to use reasonable best efforts to cooperate in NRG's efforts to obtain the financing. There are no financing conditions to the NRG Merger and the NRG Merger is not conditioned upon the completion of the Debt Offers or the funding of the financing.

In addition, we will experience an ownership change under the applicable tax rules as a result of the NRG Merger. Immediately following the NRG Merger, we and NRG will be members of the same consolidated federal income tax group. The ability of this consolidated tax group to deduct the pre-NRG Merger NOL carry forwards of GenOn against the post-merger taxable income of the group will be substantially limited as a result of the ownership change.

We anticipate completing the NRG Merger by the first quarter of 2013. Prior to the completion of the NRG Merger, we and NRG will continue to operate as independent companies. Except for specific references to the pending NRG Merger, the disclosures contained in this report on Form 10-Q relate solely to us. Information concerning the proposed NRG Merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4, which NRG will file with the Securities and Exchange Commission in connection with the NRG Merger.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This section is intended to provide the reader with information that will assist in understanding our interim financial statements, the changes in those financial statements from period to period and the primary factors contributing to those changes. The following discussion should be read in conjunction with our interim financial statements and our 2011 Annual Report on Form 10-K.

Overview

We are a wholesale generator with approximately 22,700 MW of net electric generating capacity located, in many cases, near major metropolitan load centers in the PJM, MISO, Northeast and Southeast regions, and California. We also operate integrated asset management and proprietary trading operations. Our customers are principally ISOs, RTOs and investor-owned utilities.

Our generating capacity is 58% in PJM, 24% in CAISO, 11% in NYISO and ISO NE, 6% in the Southeast and 1% in MISO. The net generating capacity of these facilities consists of approximately 39% baseload, 42% intermediate and 19% peaking capacity. Our coal facilities generally dispatch as baseload capacity, although some dispatch as intermediate capacity, and our gas, oil and dual fuel plants primarily dispatch as intermediate and/or peaking capacity.

Proposed Merger with NRG. On July 20, 2012, we entered into the NRG Merger Agreement with NRG Energy, Inc. and a direct wholly-owned subsidiary of NRG. Upon the terms and subject to the conditions set forth in the NRG Merger Agreement, which has been approved by the boards of directors of GenOn and NRG, a wholly-owned subsidiary of NRG will merge with and into GenOn, with GenOn continuing as the surviving corporation and a wholly owned subsidiary of NRG.

Upon closing of the NRG Merger, each issued and outstanding share of our common stock will automatically convert into the right to receive 0.1216 shares of common stock of NRG based on the exchange ratio. In addition, certain stock options and restricted stock units will immediately vest. See note 6 to our interim financial statements.

Completion of the NRG Merger is contingent upon, among other things, (a) approvals by NRG stockholders of the issuance of NRG common stock in the NRG Merger and the approval and adoption of the amendment to NRG's certificate of incorporation to allow the size of NRG's board of directors to be increased to 16 in connection with the closing of the NRG Merger, (b) adoption of the NRG Merger Agreement by our stockholders, (c) effectiveness of an NRG registration statement on Form S-4 and approval of the New York Stock Exchange listing for the NRG common stock to be issued in the NRG Merger, (d) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and (e) receipt of all required regulatory approvals, including approvals from the FERC, the Public Utility Commission of Texas, and the New York Public Service Commission (or the determination by the Public Utility Commission of Texas and the New York Public Service Commission that no approval is required).

In addition, we will experience an ownership change under the applicable tax rules as a result of the NRG Merger. Immediately following the NRG Merger, we and NRG will be members of the same consolidated federal income tax group. The ability of this consolidated tax group to deduct the pre-NRG Merger NOL carry forwards of GenOn against the post-merger taxable income of the group will be substantially limited as

a result of the ownership change.

We anticipate completing the NRG Merger by the first quarter of 2013. Prior to the completion of the NRG Merger, we and NRG will continue to operate as independent companies. Except for specific references to the pending NRG Merger, the disclosures contained in this report on Form 10-Q relate solely to us. Information concerning the proposed NRG Merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4, which NRG will file with the Securities and Exchange Commission in connection with the NRG Merger.

Table of Contents***Expected Retirements, Mothballing or Long-Term Protective Layup of Generating Facilities***

We are subject to extensive environmental regulation by federal, state and local authorities under a variety of statutes, regulations and permits that address discharges into the air, water and soil, and the proper handling of solid, hazardous and toxic materials and waste. Complying with increasingly stringent environmental requirements involves significant capital and operating expenses. To the extent forecasted returns on investments necessary to comply with environmental regulations are insufficient for a particular facility, we plan to deactivate that facility. In determining the forecasted returns on investments, we factor in forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes and other factors. We deactivated the following coal-fired units at the referenced times: Niles unit 2 (108 MW) June 2012 and Elrama units 1-3 (289 MW) mothballed June 2012 (plan to retire in March 2014). We expect to deactivate the following generating capacity, primarily coal-fired units, at the referenced times: Niles unit 1 (109 MW) October 2012, Elrama unit 4 (171 MW) mothball October 2012 (plan to retire in March 2014), Portland (401 MW) January 2015, Avon Lake (732 MW) April 2015, New Castle (330 MW) April 2015, Titus (243 MW) April 2015, Shawville (597 MW) place in long-term protective layup in April 2015 and Glen Gardner (160 MW) May 2015. The foregoing eight generating facilities contributed 13% to our realized gross margin during the year of 2011. We filed for RMR arrangements for Niles unit 1 and Elrama unit 4 that are in effect from June 1 through September 30, 2012. See *Regulatory Matters* below for further discussion.

We expect industry retirements of coal-fired generating facilities to contribute to a tightening of supply and demand fundamentals and higher prices for the remaining generating facilities will more than offset reduced earnings from our unit deactivations. Consequently, we expect the resulting higher market prices to provide adequate returns on investment in environmental controls necessary to meet promulgated and anticipated requirements. Accordingly, we expect to invest approximately \$603 million to \$742 million over the next decade for selective catalytic reduction emissions controls and other major environmental controls to meet certain air and water quality requirements, which we expect to fund from existing sources of liquidity.

In addition to the deactivations of the above facilities, we plan to retire our Potomac River facility in October 2012 and our Contra Costa facility in May 2013. See note 2 to our interim financial statements.

Hedging Activities

We hedge economically a substantial portion of our PJM coal-fired baseload generation and certain of our other generation. We generally do not hedge our intermediate and peaking units for tenors greater than 12 months. We hedge economically using products which we expect to be effective to mitigate the price risk of our generation. However, as a result of market liquidity limitations, our hedges often are not an exact match for the generation being hedged, and we have some risks resulting from price differentials for different delivery points. In addition, we have risks for implied differences in heat rates when we hedge economically power using natural gas. Currently, a significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties. At July 9, 2012, our aggregate hedge levels based on expected generation for each year were as follows:

	2012(1)	2013	2014	2015	2016
Power	91%	76%	35%	18%	11%
Fuel	84%	37%	16%	9%	9%

(1) Percentages represent the period from August through December 2012.

Dodd-Frank Act

The Dodd-Frank Act, which was enacted in July 2010, increases the regulation of transactions involving OTC derivative financial instruments.

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Under the Dodd-Frank Act, entities defined as swap dealers and major swap participants will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. The CFTC and the United States Securities and Exchange Commission adopted a joint rule further defining the terms swap dealer and major swap participant among others. We are currently reviewing the definitions in the rule to determine the impact, if any, on our commercial activity. Although we do not expect our commercial activity to result in our designation as a swap dealer or major swap participant, the swap dealer definition in particular is ambiguous in certain respects and the designation as such will be decided by facts and circumstance tests.

In addition, in early July 2012, the swap definition and end-user exemption final rules were approved by the CFTC and we expect they will be published in the Federal Register soon. Once published, the swap definition rule will trigger a 60-day clock for enforceability of some Dodd-Frank Act requirements, including spot-month position limits for designated energy, futures and price-linked swaps. We think ambiguity remains as to electric power ISO/RTO products, including Financial Transmission Rights. Several ISOs, including PJM, CAISO, ISO-NE and the NYISO, have filed exemption applications with the CFTC; however, the CFTC has not yet responded to their exemption requests. The CFTC extended the exemptive relief from certain provisions of the Commodity Exchange Act to December 31, 2012, or until a date the CFTC may otherwise determine with respect to a particular requirement under the Commodity Exchange Act.

Capital Expenditures and Capital Resources

During the six months ended June 30, 2012, we invested \$327 million for capital expenditures, excluding capitalized interest paid. Capital expenditures for the period primarily related to the construction of the Marsh Landing generating facility, a \$107.1 million settlement payment resulting from the scrubber contract litigation, and maintenance capital expenditures. We incurred \$1.7 billion in capital expenditures from 2007 to 2012 for compliance with the Maryland Healthy Air Act. See note 10 to our interim financial statements for further discussion of the scrubber contract litigation settlement.

The following table details the expected timing of payments for our estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for the remainder of 2012 and 2013:

	July 1, 2012 through December 31, 2012		2013
	(in millions)		
Maintenance	\$	63	\$ 133
Environmental		34	119
Construction:			
Marsh Landing generating facility		211	56
Other		5	
Other		8	10
Total	\$	321	\$ 318

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures. We plan to fund a substantial portion of the total capital expenditures for the Marsh Landing generating facility pursuant to the GenOn Marsh Landing project financing facility entered into in October 2010. Other environmental capital expenditures set forth above could significantly increase subject to the content and timing of final rules and future market conditions.

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Environmental Matters

Federal Rules Regarding CO₂. In light of the United States Supreme Court ruling in *Massachusetts v. EPA* that greenhouse gases fit within the Clean Air Act's definition of air pollutant, the EPA has proposed and promulgated regulations regarding the emission of greenhouse gases. In September 2009, the EPA issued a rule that requires owners of facilities in many sectors of the economy, including power generation, to report annually to the EPA the quantity and source of greenhouse gas emissions released from those facilities. In addition to this reporting requirement, the EPA has promulgated several rules that address greenhouse gas emissions. In December 2009, under a portion of the Clean Air Act that regulates vehicles, the EPA determined that elevated concentrations of greenhouse gases in the atmosphere endanger the public's health and welfare through their contribution to climate change (Endangerment Finding). In April 2010, the EPA finalized a rule to regulate greenhouse gases from vehicles beginning in model year 2012 (Vehicle Rule). In April 2010, the EPA also issued its Reconsideration of Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs (Tailoring Rule), which addresses the scope of pollutants subject to certain permitting requirements under the Clean Air Act as well as when such requirements become effective. The EPA has stated that, because of the vehicle rule, emissions of greenhouse gases from new stationary sources such as power plants and from major modifications to such sources are subject to certain Clean Air Act permitting requirements as of January 2011. These permitting requirements require such sources to use best available control technology to limit their greenhouse gases. Legal challenges to the Endangerment Finding, the Vehicle Rule and the Tailoring Rule were consolidated and in June 2012, the United States Court of Appeals for the District of Columbia Circuit denied or dismissed the petitions seeking review of these rules.

In April 2012, the EPA proposed a rule under the New Source Performance Standard section of the Clean Air Act that will limit the CO₂ emissions from new fossil-fuel-fired boilers, integrated gasification combined cycle units and stationary combined cycle turbine units greater than 25 MWs. The proposed limit is 1000 pounds of CO₂ per MWh, which cannot be achieved by coal-fired units unless technology to capture and store CO₂ is installed, which is not commercially available and faces several unresolved legal and regulatory issues. The proposed rule does not apply to simple cycle combustion turbines or existing units. Even though this proposed rule has not been finalized, it is applicable from the time it was proposed unless the EPA issues a final rule that is different or the courts or the United States Congress modify it. We expect the EPA to issue another rule that will require states to develop CO₂ standards that would be applicable to existing fossil-fueled generating facilities.

Canal NPDES and SWD Permit. In August 2008, the EPA renewed the NPDES permit for the Canal generating facility but sought to impose a requirement that the facility install a closed cycle cooling system. The same permit was concurrently issued by MADEP as a state SWD permit. We appealed both the NPDES permit and the SWD permit. In December 2008, the EPA requested a stay to the appeal proceedings, withdrew the provisions related to the closed cycle cooling requirements and re-noticed those provisions for additional public comment. Rather than grant the stay sought by the EPA, the Environmental Appeals Board has dismissed the appeal without prejudice. The parallel MADEP proceeding, which had been stayed, also has been dismissed without prejudice. In the absence of permit renewals, the Canal generating facility will continue to operate under its current NPDES and SWD permits.

Regulatory Matters

State and local regulatory authorities historically have overseen the distribution and sale of electricity at retail to the ultimate end user, as well as the siting, permitting and construction of generating and transmission facilities. In some markets, state regulators have proposed initiatives to provide long-term contracts for new generating capacity in order, among other things, to reduce future capacity prices in PJM.

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PJM. In January 2011, New Jersey enacted legislation which requires the New Jersey Board of Public Utilities to implement a Long Term Capacity Agreement Pilot Program providing for new generating capacity in the state. The new generating capacity would be required to participate and be accepted as a capacity resource in the PJM capacity market. The New Jersey Board of Public Utilities awarded three contracts for new generating capacity as required by the statute. In May 2012, two of the three projects were accepted as a capacity resource in the 2015/2016 RPM capacity auction, while the third project failed to clear the auction. Because the law could have a negative effect on capacity prices in PJM in future years, in February 2011, a group of companies filed suit in the

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U.S. District Court for the District of New Jersey asking the court to declare the New Jersey legislation unconstitutional. We are not a party to the ongoing proceeding.

In September 2011, the MPSC issued a request for proposal for up to 1,500 MWs of new natural gas-fired generating capacity to be located in the Southwestern Mid-Atlantic Area Council zone of PJM. The order provided for project submittals and a MPSC hearing in January 2012 to determine whether new generating capacity is needed to meet the long-term anticipated demand in Maryland. We filed comments with the MPSC stating there is no need for additional capacity at this time. In April 2012, the MPSC ordered the state's three public utility companies to enter into a contract with CPV Maryland, LLC for the output of a new 661 MW combined cycle facility in the Southwestern Mid-Atlantic Area Council zone of PJM to be constructed and operational by 2015. The contract required the generating facility be bid into the PJM capacity market in a manner consistent with the PJM tariff. CPV Maryland, LLC bid into the PJM capacity market for the 2015/2016 auction year and cleared the auction. In April 2012, certain companies (not including us) filed in the U.S. District Court for the District of Maryland a complaint for declaratory and injunctive relief barring the implementation of the MPSC order. There have been petitions for judicial review on the administrative record filed by certain companies (not including us) in various circuit courts in Maryland. It is possible that the MPSC will continue to seek additional contracts for new generating capacity. Such contracts could result in reduced future capacity prices and energy prices in PJM. A number of companies (including us) have publicly indicated that they intend to pursue changes in the PJM auction rules to ensure that future RPM auctions are not adversely affected as a result of such contracting and bidding practices.

MISO. Our MISO generating facility sells electricity into the markets operated by MISO. MISO manages the transmission system and provides open access to its transmission system and markets to all market participants on an equal basis. MISO operates physical and financial energy markets using a locational marginal pricing model, which calculates a price for every generator and load point within MISO and is similar to the model utilized by PJM. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. MISO does not currently administer a centralized capacity market; instead it uses an enforceable Planning Reserve Margin to ensure resource adequacy. In July 2011, MISO filed with the FERC a proposal for an auction mechanism to meet locational reserve requirements to be established for each planning year. In June 2012, the FERC issued an order accepting many elements of the MISO filing; however, the FERC rejected the requirement of a mandatory capacity auction and instead implemented a voluntary auction for load serving entities that were capacity deficient for the planning year. The FERC directed MISO to make further filings to implement the June 2012 FERC order. Depending upon the timing of the FERC's acceptance of MISO's additional filings, the first voluntary auction will take place in April 2013 for the June 2013 to May 2014 planning year. MISO also has an ancillary services market. A feature of the ancillary services market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of \$1,000/MWh.

RMR. In May 2012, we filed with the FERC an RMR rate schedule governing operation of unit 4 of the Elrama generating facility and unit 1 of the Niles generating facility. PJM determined that each of these units was needed past their planned deactivation date of June 1, 2012 to maintain transmission system reliability on the PJM system pending the completion of transmission upgrades. The RMR rate schedule sets forth the terms, conditions and cost-based rates under which we will continue to operate the units for reliability purposes through September 30, 2012, which is the date PJM indicated the units would no longer be needed for reliability. In July 2012, the FERC accepted our RMR rate schedule subject to hearing and settlement procedures. In the settlement discussions ordered by the FERC or in any subsequent hearing, our RMR rate schedule may be modified from that which we filed. The rates we are currently charging are subject to refund pending a ruling or settlement.

Commodity Prices and Generation Volumes

The prices for power and natural gas are low compared to several years ago. The energy gross margin from our baseload coal units is negatively affected by these price levels. For that portion of the volumes of generation that we have hedged, we are generally unaffected by subsequent changes in commodity prices because our realized gross margin will reflect the contractual prices of our power and fuel contracts. We continue

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to add economic hedges to manage the risks associated with volatility in prices and to achieve more predictable realized gross margin. However, we expect realized gross margin will be lower for 2012 compared with 2011.

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We experienced a decrease in power generation volumes during the six months ended June 30, 2012, as compared to the same period in 2011, particularly in our Eastern PJM and Western PJM/MISO segments. The decrease in generation occurred primarily at our coal-fired facilities and was caused by a combination of unseasonably mild weather and contracting dark spreads resulting from decreasing natural gas prices. Consequently, we have significant coal inventories at our generating facilities and, in the case of our Mid-Atlantic facilities, such inventories were at the maximum available storage capacity of such facilities. In April 2012, we issued notices of force majeure under the respective coal contracts as it was impossible for us to take coal at such facilities. Recently we issued notices to the affected coal suppliers that the force majeure conditions have abated and, accordingly, we expect to resume shipments in accordance with the coal contracts. A number of the suppliers disputed our invocation of force majeure. In our communications with the affected coal suppliers, we have advised them that we expect to take all the coal for which we have contracted, at the contracted prices, as we are able to do so.

Capacity Sales

Capacity sales, whether made bilaterally or through periodic auction processes in the ISO and RTO markets in which we participate, provide an important source of predictable revenues for us over the contracted periods. In the recent PJM RPM auction we secured over \$500 million of capacity revenue for the planning year 2015/2016. At July 9, 2012, total projected contracted capacity and PPA revenues for which prices have been set for the last six months of 2012 and 2013-2016 are \$3.4 billion.

Results of Operations

Non-GAAP Performance Measures. The following discussion includes the non-GAAP financial measures realized gross margin and unrealized gross margin to reflect how we manage our business. In our discussion of the results of our reportable segments, we include the components of realized gross margin, which are energy, contracted and capacity, and realized value of hedges. Management generally evaluates our operating results excluding the impact of unrealized gains and losses. When viewed with our GAAP financial results, these non-GAAP financial measures may provide a more complete understanding of factors and trends affecting our business. Realized gross margin represents our gross margin (excluding depreciation and amortization) less unrealized gains and losses on derivative financial instruments. Conversely, unrealized gross margin represents our unrealized gains and losses on derivative financial instruments. None of our derivative financial instruments recorded at fair value is designated as a hedge (other than our interest rate swaps) and changes in their fair values are recognized currently in income as unrealized gains or losses. As a result, our financial results are, at times, volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices. Realized gross margin, together with its components energy, contracted and capacity, and realized value of hedges, provide a measure of performance that eliminates the volatility reflected in unrealized gross margin, which is created by significant shifts in market values between periods.

We also disclose the non-GAAP financial measures adjusted net income/loss and adjusted EBITDA as consolidated performance measures, which exclude unrealized gross margin. As indicated above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted net income/loss and adjusted EBITDA also exclude, as applicable: (a) Mirant/RRI Merger-related costs, (b) lower of cost or market adjustments to our commodity inventories, net of recoveries, (c) impairment losses, (d) gain/loss on early extinguishment of debt, (e) large scale remediation and settlement costs, (f) major litigation costs, net of recoveries, (g) costs to deactivate generating facilities, (h) advance settlement of an out-of-market contract obligation, (i) reversal of Potomac River obligation under the 2008 agreement with the City of Alexandria and (j) certain other items. We exclude or adjust for these items to provide a more meaningful representation of our ongoing results of operations.

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We use these non-GAAP financial measures in communications with investors, analysts, rating agencies, banks and other parties. Adjusted EBITDA is a key performance metric in our employee incentive compensation structure for annual bonuses. We think these non-GAAP financial measures provide meaningful representations of our consolidated operating performance and are useful to us and others in facilitating the analysis of our results of operations from one period to another. We view adjusted EBITDA as providing a measure of operating results unaffected by differences in capital structures, capital investment cycles and ages of assets among otherwise

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comparable companies. We encourage our investors to review our financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

The foregoing non-GAAP financial measures may not be comparable to similarly titled non-GAAP financial measures used by other companies.

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011*Consolidated Financial Performance*

We reported a net loss of \$228 million and \$138 million during the three months ended June 30, 2012 and 2011, respectively. The change in net loss is detailed as follows:

	Three Months Ended June 30,		Increase/ (Decrease)
	2012	2011 (in millions)	
Realized gross margin	\$ 357	\$ 440	\$ (83)
Unrealized gross margin	(142)	(18)	(124)
Total gross margin (excluding depreciation and amortization)	215	422	(207)
Operating expenses:			
Operations and maintenance	264	372	(108)
Depreciation and amortization	90	90	
Loss on sales of assets, net		2	(2)
Total operating expenses	354	464	(110)
Operating loss	(139)	(42)	(97)
Other expense, net:			
Interest expense, net	(85)	(96)	(11)
Total other expense, net	(85)	(96)	(11)
Loss before income taxes	(224)	(138)	(86)
Provision for income taxes	4		4
Net loss	\$ (228)	\$ (138)	\$ (90)

Realized Gross Margin. Our realized gross margin decrease of \$83 million was principally a result of the following:

- \$96 million decrease in energy, primarily as a result of (a) a \$75 million decrease resulting from reduced generation volumes as a result of contracting dark spreads for our coal-fired units, partially offset by an increase in generation volumes for our gas-fired units as a result of expanding spark spreads and (b) a \$21 million decrease in our Energy Marketing segment primarily as a result of decreases in income from proprietary trading; and

- \$34 million decrease in contracted and capacity primarily resulting from lower capacity prices in our Eastern PJM and Western PJM/MISO segments; partially offset by
- \$47 million increase in realized value of hedges, primarily as a result of a \$77 million increase in power hedges primarily resulting from lower prices, offset in part by a \$28 million decrease in coal hedges primarily resulting from lower prices.

Unrealized Gross Margin. Our unrealized gross margin for both periods reflects the following:

- unrealized losses of \$142 million during the three months ended June 30, 2012, which included \$93 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a \$49 million net decrease in the value of hedge and proprietary trading contracts for future periods. The decrease in value was primarily related to decreases in forward coal prices

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and the recognition of certain coal agreements at fair value beginning in May 2012, partially offset by decreases in forward power and natural gas prices in future years; and

- unrealized losses of \$18 million during the three months ended June 30, 2011, which included \$58 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a \$40 million net increase in the value of hedge and proprietary trading contracts for future periods. The increase in value was primarily related to decreases in forward power and natural gas prices and increases in forward coal prices.

Operating Expenses. Our operating expenses decrease of \$110 million was principally a result of the following:

- \$108 million decrease in operations and maintenance expense primarily related to the following:
 - \$33 million change in large scale remediation and settlement costs as we accrued \$30 million for remediation costs at our Maryland ash facilities in 2011 and reversed a net \$3 million in 2012;
 - \$32 million decrease primarily as a result of lower project, outage and maintenance expenses;
 - \$31 million reversal of the previously recorded Potomac River obligation under the 2008 agreement with the City of Alexandria; and
 - \$12 million decrease in Mirant/RRI Merger-related costs, primarily for severance, partially offset by
- \$11 million reversal of Montgomery County Carbon levy assessment recorded in 2011, which included \$8 million related to the refund received in the third quarter of 2011.

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The decrease of \$11 million was principally a result of an \$8 million decrease related to lower interest expense as a result of the repayment in 2011 of GenOn Americas Generation senior unsecured notes and PEDFA bonds.

Adjusted Net Loss and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted net loss and adjusted EBITDA to net loss on a historical basis. See the discussion above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. The following compares actual results for the three months ended June 30, 2012 to the same period of 2011 and provides discussion of the changes.

	Three Months Ended June 30,	
	2012	2011
	(in millions)	
Net Loss	\$ (228)	\$ (138)
Unrealized losses	142	18
Mirant/RRI Merger-related costs	2	14
Lower of cost or market inventory adjustments, net	3	(4)
Gain on early extinguishment of debt		(1)
Major litigation costs, net of recoveries	2	7
Reversal of Montgomery County carbon levy assessment for prior year		(8)
Costs to deactivate generating facilities	3	
Large scale remediation and settlement costs	(3)	30
Reversal of Potomac River settlement obligation	(31)	
Other, net	3	
Adjusted Net Loss	(107)	(82)
Interest expense, net	85	96
Provision for income taxes	4	
Depreciation and amortization	90	90
Adjusted EBITDA	\$ 72	\$ 104

Adjusted EBITDA was \$72 million for the three months ended June 30, 2012 compared to \$104 million for the same period of 2011. The decline was primarily related to a reduction in energy gross margin as a result of reduced generation volumes and lower contracted and capacity revenues in Eastern PJM and Western PJM/MISO. The decline was partially offset by the increased realized value of hedges and lower adjusted operating and other expenses primarily from Mirant/RRI Merger cost savings.

The adjusted net loss was \$107 million for the three months ended June 30, 2012 compared to the adjusted net loss of \$82 million for the same period of 2011. The increase in adjusted net loss was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in interest expense.

Our net loss was \$228 million for the three months ended June 30, 2012 compared to a net loss of \$138 million for the same period of 2011. The increase in net loss was primarily a result of a decrease in unrealized gross margin and the same items that affected adjusted net loss. These

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increases were partially offset by lower adjusted operating and other expenses primarily from Mirant/RRI Merger cost savings, a decrease in large scale remediation and settlement costs, reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria and a decrease in Mirant/RRI Merger-related costs.

Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. We have five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. See note 9 to our interim financial statements for changes in our net generating capacity from 24,600 MW at January 1, 2011 to 22,670 MW at June 30, 2012.

Table of Contents**Gross Margin Overview**

The following tables detail realized and unrealized gross margin by operating segments:

	Three Months Ended June 30, 2012						Total
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations		
	(in millions)						
Energy	\$ 30	\$ 29	\$ 1	\$ 2	\$ (3)	\$ 59	
Contracted and capacity	63	68	32		23	186	
Realized value of hedges	87	23	1		1	112	
Total realized gross margin	180	120	34	2	21	357	
Unrealized gross margin	(113)	(31)	(4)	9	(3)	(142)	
Total gross margin(1)	\$ 67	\$ 89	\$ 30	\$ 11	\$ 18	\$ 215	

	Three Months Ended June 30, 2011						Total
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations		
	(in millions)						
Energy	\$ 50	\$ 69	\$ 4	\$ 23	\$ 9	\$ 155	
Contracted and capacity	81	84	31		24	220	
Realized value of hedges	65		1		(1)	65	
Total realized gross margin	196	153	36	23	32	440	
Unrealized gross margin	(12)	(17)	(1)	11	1	(18)	
Total gross margin(1)	\$ 184	\$ 136	\$ 35	\$ 34	\$ 33	\$ 422	

(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales, our proprietary trading and fuel oil management activities, and natural gas transportation and storage activities.

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, RMR arrangements, PPAs and tolling agreements, and ancillary services.

Realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts and the difference between market prices and contract costs for fuel. Power hedging contracts include sales of both power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of our physical assets.

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Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

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Our total margin capture factor was 92% and 91% during the three months ended June 30, 2012 and 2011, respectively. The following table summarizes power generation volumes by segment:

	Three Months Ended June 30,		Increase/ (Decrease)	Increase/ (Decrease)(1)
	2012	2011		
	(in gigawatt hours)			
Eastern PJM:				
Baseload	1,374	2,612	(1,238)	(47)%
Intermediate	1,371	248	1,123	NM
Peaking	45	34	11	32%
Total Eastern PJM	2,790	2,894	(104)	(4)%
Western PJM/MISO:				
Baseload	3,199	4,758	(1,559)	(33)%
Intermediate	8		8	NM
Peaking	26	27	(1)	(4)%
Total Western PJM/MISO	3,233	4,785	(1,552)	(32)%
California:				
Intermediate	154	93	61	66%
Peaking	2	2		0%
Total California	156	95	61	64%
Other Operations:				
Baseload	600	486	114	23%
Intermediate	30	68	(38)	(56)%
Peaking	133	89	44	49%
Total Other Operations	763	643	120	19%
Total	6,942	8,417	(1,475)	(18)%

(1) NM means not meaningful.

The total decrease in power generation volumes during the three months ended June 30, 2012, as compared to the same period in 2011, is explained by segment below.

Eastern PJM. The net decrease in generation volumes results from a decrease in our baseload generation volumes primarily as a result of contracting dark spreads for coal-fired units, offset in part by an increase in our intermediate generation volumes for gas-fired units primarily as a result of expanding spark spreads.

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Western PJM/MISO. The net decrease in generation volumes results from a decrease in our baseload generation volumes primarily as a result of contracting dark spreads and an outage at one of our generating facilities.

California. The net increase in generation volumes results from an increase in our intermediate generation volumes primarily as a result of the commencement of a tolling agreement in July 2011 in conjunction with expanding spark spreads.

Other Operations. The net increase in generation volumes results from an increase in our baseload generation volumes primarily as a result of the commencement of a PPA in June 2012 and an increase in requested energy from a tolling agreement. These increases were offset in part by a decrease in our intermediate generation volumes for our facilities located in the Northeast as a result of outages.

Table of Contents**Eastern PJM**

	Three Months Ended June 30,			Increase/ (Decrease)
	2012	2011		
	(in millions)			
Gross margin:				
Energy	\$ 30	\$ 50	\$	(20)
Contracted and capacity	63	81		(18)
Realized value of hedges	87	65		22
Total realized gross margin	180	196		(16)
Unrealized gross margin	(113)	(12)		(101)
Total gross margin (excluding depreciation and amortization)	67	184		(117)
Operating expenses:				
Operations and maintenance	85	146		(61)
Depreciation and amortization	34	34		
Total operating expenses, net	119	180		(61)
Operating income (loss)	\$ (52)	\$ 4	\$	(56)

Gross Margin

The decrease of \$16 million in realized gross margin was principally a result of the following:

- \$20 million decrease in energy, primarily as a result of a decrease in generation volumes for coal-fired units as a result of contracting dark spreads, partially offset by an increase in generation volumes for gas-fired units as a result of expanding spark spreads; and
- \$18 million decrease in contracted and capacity primarily as a result of lower capacity prices; partially offset by
- \$22 million increase in realized value of hedges, primarily as a result of a \$36 million increase in power hedges primarily resulting from lower prices, offset in part by a \$14 million decrease in coal hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of \$113 million during the three months ended June 30, 2012, which included \$73 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a \$40 million net decrease in the value of hedge contracts for future periods. The decrease in value was primarily related to decreases in forward coal prices and the recognition of certain coal agreements at fair value beginning in May 2012, partially offset by decreases in forward power and natural gas prices in future years; and

- unrealized losses of \$12 million during the three months ended June 30, 2011, which included \$60 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, partially offset by a \$48 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and increases in forward coal prices.

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Operating Expenses.

The decrease of \$61 million in operating expenses was principally a result of the following:

- \$61 million decrease in operations and maintenance expense primarily related to the following:
- \$33 million change in large scale remediation and settlement costs as we accrued \$30 million for remediation costs at our Maryland ash facilities in 2011 and reversed a net \$3 million in 2012;
- \$31 million reversal of the previously recorded Potomac River obligation under the 2008 agreement with the City of Alexandria; partially offset by
- \$11 million reversal of Montgomery County Carbon levy assessment in 2011, which included \$8 million related to the refund received in the third quarter of 2011.

Western PJM/MISO

	Three Months Ended June 30,			Increase/ (Decrease)
	2012	2011		(Decrease)
	(in millions)			
Gross margin:				
Energy	\$ 29	\$ 69	\$	(40)
Contracted and capacity	68	84		(16)
Realized value of hedges	23			23
Total realized gross margin	120	153		(33)
Unrealized gross margin	(31)	(17)		(14)
Total gross margin (excluding depreciation and amortization)	89	136		(47)
Operating expenses:				
Operations and maintenance	114	149		(35)
Depreciation and amortization	31	31		
Total operating expenses, net	145	180		(35)
Operating loss	\$ (56)	\$ (44)	\$	(12)

Gross Margin

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The decrease of \$33 million in realized gross margin was principally a result of the following:

- \$40 million decrease in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads; and
- \$16 million decrease in contracted and capacity primarily as a result of lower capacity prices; partially offset by
- \$23 million increase in realized value of hedges, primarily as a result of a \$37 million increase in power hedges primarily resulting from lower prices, offset in part by a \$14 million decrease in coal hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of \$31 million during the three months ended June 30, 2012, which included \$25 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a \$6 million net decrease in the value of hedge contracts for future periods primarily related to decreases in forward coal prices and the recognition of certain coal agreements at fair value beginning in May 2012; and

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- unrealized losses of \$17 million during the three months ended June 30, 2011, which included a \$16 million net decrease in the value of hedge contracts for future periods primarily related to decreases in forward power prices in the near term and the amortization of option premiums and \$1 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The decrease of \$35 million in operating expenses was primarily as a result of lower project, outage and maintenance expenses.

California

	Three Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		
Gross margin:			
Energy	\$ 1	\$ 4	\$ (3)
Contracted and capacity	32	31	1
Realized value of hedges	1	1	
Total realized gross margin	34	36	(2)
Unrealized gross margin	(4)	(1)	(3)
Total gross margin (excluding depreciation and amortization)	30	35	(5)
Operating expenses:			
Operations and maintenance	38	39	(1)
Depreciation and amortization	12	11	1
Total operating expenses, net	50	50	
Operating loss	\$ (20)	\$ (15)	\$ (5)

Gross Margin

Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for the majority of the capacity from these units. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Therefore, our gross margin generally is not affected by changes in power generation volumes from these facilities.

Energy Marketing

	Three Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		

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Gross margin:					
Energy	\$	2	\$	23	\$ (21)
Total realized gross margin		2		23	(21)
Unrealized gross margin		9		11	(2)
Total gross margin (excluding depreciation and amortization)		11		34	(23)
Operating expenses:					
Operations and maintenance		1		(2)	3
Depreciation and amortization				1	(1)
Total operating expenses, net		1		(1)	2
Operating income	\$	10	\$	35	\$ (25)

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Gross Margin

The decrease of \$21 million in realized gross margin was primarily as a result of a decrease in income from proprietary trading.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of \$9 million during the three months ended June 30, 2012, which included \$7 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period and a \$2 million net increase in the value of contracts for future periods; and
- unrealized gains of \$11 million during the three months ended June 30, 2011, which included a \$7 million net increase in the value of contracts for future periods and \$4 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Other Operations

	Three Months Ended June 30,		Increase/ (Decrease)
	2012	2011 (in millions)	
Gross margin:			
Energy	\$ (3)	\$ 9	\$ (12)
Contracted and capacity	23	24	(1)
Realized value of hedges	1	(1)	2
Total realized gross margin	21	32	(11)
Unrealized gross margin	(3)	1	(4)
Total gross margin (excluding depreciation and amortization)	18	33	(15)
Operating expenses:			
Operations and maintenance	26	40	(14)
Depreciation and amortization	13	13	
Loss on sales of assets, net		2	(2)
Total operating expenses, net	39	55	(16)
Operating loss	\$ (21)	\$ (22)	\$ 1

Gross Margin

The decrease of \$11 million in realized gross margin was principally a result of a decrease of \$12 million in energy primarily as a result of decreases in prices.

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The decrease of \$16 million in operating expenses was principally the result of a decrease of \$14 million in operations and maintenance expense primarily related to a decrease of \$12 million in Mirant/RRI Merger-related costs, primarily for severance.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011*Consolidated Financial Performance*

We reported a net loss of \$260 million and \$249 million during the six months ended June 30, 2012 and 2011, respectively. The change in net loss is detailed as follows:

	Six Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		
Realized gross margin	\$ 700	\$ 932	\$ (232)
Unrealized gross margin	(42)	(97)	55
Total gross margin (excluding depreciation and amortization)	658	835	(177)
Operating expenses:			
Operations and maintenance	572	677	(105)
Depreciation and amortization	178	176	2
(Gain) loss on sales of assets, net	(8)	1	(9)
Total operating expenses	742	854	(112)
Operating loss	(84)	(19)	(65)
Other income (expense), net:			
Interest expense, net	(174)	(205)	(31)
Other, net	2	(22)	(24)
Total other expense, net	(172)	(227)	(55)
Loss before income taxes	(256)	(246)	(10)
Provision for income taxes	4	3	1
Net loss	\$ (260)	\$ (249)	\$ (11)

Realized Gross Margin. Our realized gross margin decrease of \$232 million was principally a result of the following:

- \$272 million decrease in energy, primarily as a result of (a) a \$184 million decrease primarily resulting from reduced generation volumes as a result of contracting dark spreads for our coal-fired units, partially offset by an increase in generation volumes for our gas-fired units as a result of expanding spark spreads, (b) a \$56 million increase in lower of cost or market inventory adjustments, net and (c) a \$52 million decrease in our Energy Marketing segment primarily as a result of decreases in income from proprietary trading and decreases in fuel oil management activities, partially offset by \$20 million related to the advance settlement of an out-of-market contract obligation. This \$20 million for the advance settlement of an out-of-market transmission contract relates to our successful permanent assignment of a long-term contract that

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was out-of-market and revalued as of the date of the Mirant/RRI Merger and recorded as a \$20 million liability. We have no further obligations under this contract, do not need it to support our ongoing operations and therefore reversed the liability; and

- \$91 million decrease in contracted and capacity primarily resulting from lower capacity prices in our Eastern PJM and Western PJM/MISO segments and the shutdown of the Potrero generating facility in our California segment in 2011; partially offset by

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- \$131 million increase in realized value of hedges, primarily as a result of a \$179 million increase in power hedges primarily resulting from lower prices, offset in part by a \$41 million decrease in coal hedges resulting from lower prices.

Unrealized Gross Margin. Our unrealized gross margin for both periods reflects the following:

- unrealized losses of \$42 million during the six months ended June 30, 2012, which included \$225 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The decrease was offset by a \$183 million net increase in the value of hedge and proprietary trading contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by decreases in forward coal prices; and

- unrealized losses of \$97 million during the six months ended June 30, 2011, which included \$127 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a \$30 million net increase in the value of hedge and proprietary trading contracts for future periods. The increase in value was primarily related to decreases in forward power and natural gas prices and increases in forward coal prices.

Operating Expenses. Our operating expenses decrease of \$112 million was principally a result of the following:

- \$105 million decrease in operations and maintenance expense primarily related to the following:
- \$36 million decrease primarily as a result of lower project, outage and maintenance expenses;
- \$33 million decrease in Mirant/RRI Merger-related costs, primarily for severance;
- \$33 million change in large scale remediation and settlement costs as we accrued \$30 million for remediation costs at our Maryland ash facilities in 2011 and reversed a net \$3 million in 2012;
- \$31 million reversal of the previously recorded Potomac River obligation under the 2008 agreement with the City of Alexandria; and
- \$13 million decrease from lower employee headcount as a result of completion of Mirant/RRI Merger integration; partially offset by

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- \$36 million in costs to deactivate generating facilities (primarily for an inventory reserve for excess materials and supplies) and
- \$8 million reversal of Montgomery County Carbon levy assessment recorded in 2011, which included \$8 million related to the refund received in the third quarter of 2011; and
- \$9 million increase in gain on sales of assets primarily as a result of the sale of our Indian River generating facility in January 2012.

Interest Expense, Net.

The decrease of \$31 million was principally a result of a \$25 million decrease related to lower interest expense as a result of the repayment in 2011 of GenOn Americas Generation senior unsecured notes and PEDFA bonds.

Other, Net.

The change of \$24 million was principally a result of \$23 million of other expense in 2011 relating to the loss on extinguishment of debt related to a \$16 million premium and a \$7 million write-off of unamortized debt issuance costs related to the GenOn North America senior notes that were repaid in 2011.

Adjusted Net Loss and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted net loss and adjusted EBITDA to net loss on a historical basis. See the discussion

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above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. The following compares actual results for the six months ended June 30, 2012 to the same period of 2011 and provides discussion of the changes.

	Six Months Ended June 30,	
	2012	2011
	(in millions)	
Net Loss	\$ (260)	\$ (249)
Unrealized losses	42	97
Mirant/RRI Merger-related costs	4	37
Lower of cost or market inventory adjustments, net	44	(12)
Loss on early extinguishment of debt		23
Major litigation costs, net of recoveries	4	7
Reversal of Montgomery County carbon levy assessment for prior year		(8)
Advance settlement of out-of-market contract obligation	(20)	
Large scale remediation and settlement costs	(3)	30
Costs to deactivate generating facilities	38	
Reversal of Potomac River settlement obligation	(31)	
Other, net	(1)	
Adjusted Net Loss	(183)	(75)
Interest expense, net	174	205
Provision for income taxes	4	3
Depreciation and amortization	178	176
Adjusted EBITDA	\$ 173	\$ 309

Adjusted EBITDA was \$173 million for the six months ended June 30, 2012 compared to \$309 million for the same period of 2011. The decline was primarily related to a reduction in energy gross margin as a result of reduced generation volumes and lower contracted and capacity revenues in Eastern PJM and Western PJM/MISO. The decline was partially offset by the increased realized value of hedges and lower adjusted operating and other expenses primarily from Mirant/RRI Merger cost savings.

The adjusted net loss was \$183 million for the six months ended June 30, 2012 compared to the adjusted net loss of \$75 million for the same period of 2011. The increase in adjusted net loss was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in interest expense, net.

Our net loss was \$260 million for the six months ended June 30, 2012 compared to a net loss of \$249 million for the same period of 2011. The increase in net loss was primarily a result of an increase in lower of cost or market inventory adjustments, net, costs incurred in 2012 to deactivate generating facilities and the same items that affected adjusted net loss. These increases were partially offset by a decrease in unrealized gross margin, a loss on early extinguishment of debt in 2011 which was not repeated in 2012, a decrease in Mirant/RRI Merger-related costs, a decrease in large scale remediation and settlement costs, the advance settlement of an out-of-market contract obligation and the reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria.

Segments

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The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. We have five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. See note 9 to our interim financial statements for changes in our net generating capacity from 24,600 MW at January 1, 2011 to 22,670 MW at June 30, 2012.

Table of Contents**Gross Margin Overview**

The following tables detail realized and unrealized gross margin by operating segments:

	Six Months Ended June 30, 2012						Total
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations		
	(in millions)						
Energy	\$ 15	\$ 24	\$ 2	\$ 24	\$ (5)	\$ 60	
Contracted and capacity	123	140	57		44	364	
Realized value of hedges	216	59	2		(1)	276	
Total realized gross margin	354	223	61	24	38	700	
Unrealized gross margin	(71)	17	(1)	12	1	(42)	
Total gross margin(1)	\$ 283	\$ 240	\$ 60	\$ 36	\$ 39	\$ 658	

	Six Months Ended June 30, 2011						Total
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations		
	(in millions)						
Energy	\$ 111	\$ 142	\$ 4	\$ 64	\$ 11	\$ 332	
Contracted and capacity	174	169	64		48	455	
Realized value of hedges	128	12	2		3	145	
Total realized gross margin	413	323	70	64	62	932	
Unrealized gross margin	(51)	(26)	(1)	(11)	(8)	(97)	
Total gross margin(1)	\$ 362	\$ 297	\$ 69	\$ 53	\$ 54	\$ 835	

(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales, our proprietary trading and fuel oil management activities, and natural gas transportation and storage activities.

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, RMR arrangements, PPAs and tolling agreements, and ancillary services.

Realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts and the difference between market prices and contract costs for fuel. Power hedging contracts include sales of both power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of our physical assets.

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Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Table of Contents**Operating Statistics**

Our total margin capture factor was 93% and 91% during the six months ended June 30, 2012 and 2011, respectively. The following table summarizes power generation volumes by segment:

	Six Months Ended June 30,		Increase/ (Decrease)	Increase/ (Decrease)(2)
	2012	2011		
Eastern PJM:				
Baseload	2,606	6,123	(3,517)	(57)%
Intermediate	1,591	266	1,325	NM
Peaking	55	52	3	6%
Total Eastern PJM	4,252	6,441	(2,189)	(34)%
Western PJM/MISO:				
Baseload	7,035	9,766	(2,731)	(28)%
Intermediate(1)	8	(2)	10	NM
Peaking	19	26	(7)	(27)%
Total Western PJM/MISO	7,062	9,790	(2,728)	(28)%
California:				
Intermediate	172	126	46	37%
Peaking	2	2		0%
Total California	174	128	46	36%
Other Operations:				
Baseload	941	864	77	9%
Intermediate	35	86	(51)	(59)%
Peaking	164	100	64	64%
Total Other Operations	1,140	1,050	90	9%
Total	12,628	17,409	(4,781)	(27)%

(1) Negative amounts denote net energy used by the generating facility.

(2) NM means not meaningful.

The total decrease in power generation volumes during the six months ended June 30, 2012, as compared to the same period in 2011, is explained by segment below.

Eastern PJM. The net decrease in generation volumes results from a decrease in our baseload generation volumes primarily as a result of contracting dark spreads for coal-fired units, offset in part by an increase in our intermediate generation volumes for gas-fired units primarily as a result of expanding spark spreads.

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Western PJM/MISO. The net decrease in generation volumes results from a decrease in our baseload generation volumes primarily as a result of contracting dark spreads.

California. The net increase in generation volumes results from an increase in our intermediate generation volumes was primarily as a result of the commencement of a tolling agreement in July 2011 in conjunction with expanding spark spreads.

Other Operations. The net increase in generation volumes results from an increase in our baseload generation volumes primarily as a result of the commencement of a PPA in June 2012 and an increase in requested energy from a tolling agreement. These increases were offset in part by a decrease in our intermediate generation volumes for our facilities located in the Northeast as a result of outages.

Table of Contents**Eastern PJM**

	Six Months Ended June 30,			Increase/ (Decrease)
	2012	2011	(in millions)	
Gross margin:				
Energy	\$ 15	\$ 111		\$ (96)
Contracted and capacity	123	174		(51)
Realized value of hedges	216	128		88
Total realized gross margin	354	413		(59)
Unrealized gross margin	(71)	(51)		(20)
Total gross margin (excluding depreciation and amortization)	283	362		(79)
Operating expenses:				
Operations and maintenance	191	252		(61)
Depreciation and amortization	67	67		
Total operating expenses, net	258	319		(61)
Operating income	\$ 25	\$ 43		\$ (18)

Gross Margin

The decrease of \$59 million in realized gross margin was principally a result of the following:

- \$96 million decrease in energy, primarily as a result of (a) a \$74 million decrease resulting from reduced generation volumes as a result of contracting dark spreads for our coal-fired units, partially offset by an increase in generation volumes for our gas-fired units as a result of expanding spark spreads and (b) a \$22 million increase in lower of cost or market inventory adjustments, net; and
- \$51 million decrease in contracted and capacity primarily as a result of lower capacity prices; partially offset by
- \$88 million increase in realized value of hedges, primarily as a result of a \$112 million increase in power hedges primarily resulting from lower prices, offset in part by a \$23 million decrease in coal hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of \$71 million during the six months ended June 30, 2012, which included \$174 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The increase was offset by a \$103 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by decreases in coal prices; and

- unrealized losses of \$51 million during the six months ended June 30, 2011, which included \$114 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a \$63 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and increases in forward coal prices.

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Operating Expenses.

The decrease of \$61 million in operating expenses was principally a result of the following:

- \$61 million decrease in operations and maintenance expense primarily related to the following:
- \$33 million change in large scale remediation and settlement costs as we accrued \$30 million for remediation costs at our Maryland ash facilities in 2011 and reversed a net \$3 million in 2012;
- \$31 million reversal of the previously recorded Potomac River obligation under the 2008 agreement with the City of Alexandria; and
- \$8 million decrease primarily relating to decreased allocated corporate overhead costs as a result of the completion of Mirant/RRI Merger integration; partially offset by
- \$8 million reversal of Montgomery County Carbon levy assessment recorded in 2011, which included \$8 million related to the refund received in the third quarter of 2011.

Western PJM/MISO

	Six Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		
Gross margin:			
Energy	\$ 24	\$ 142	\$ (118)
Contracted and capacity	140	169	(29)
Realized value of hedges	59	12	47
Total realized gross margin	223	323	(100)
Unrealized gross margin	17	(26)	43
Total gross margin (excluding depreciation and amortization)	240	297	(57)
Operating expenses:			
Operations and maintenance	244	260	(16)
Depreciation and amortization	61	59	2
Gain on sales of assets, net	(1)		(1)
Total operating expenses, net	304	319	(15)
Operating loss	\$ (64)	\$ (22)	\$ (42)

Gross Margin

The decrease of \$100 million in realized gross margin was principally a result of the following:

- \$118 million decrease in energy, primarily as a result of (a) a \$99 million decrease resulting from reduced generation volumes as a result of contracting dark spreads and (b) a \$19 million increase in lower of cost or market inventory adjustments, net; and
- \$29 million decrease in contracted and capacity primarily as a result of lower capacity prices; partially offset by
- \$47 million increase in realized value of hedges, primarily as a result of a \$65 million increase in power hedges primarily resulting from lower prices, offset in part by an \$18 million decrease in coal hedges resulting from lower prices.

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Our unrealized gross margin for both periods reflects the following:

- unrealized gains of \$17 million during the six months ended June 30, 2012, which included a \$70 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by decreases in coal prices. The increase was offset by \$53 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and
- unrealized losses of \$26 million during the six months ended June 30, 2011, which included a \$23 million net decrease in the value of hedge contracts for future periods primarily related to decreases in forward power prices in the near term and the amortization of option premiums and \$3 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The decrease of \$15 million in operating expenses was principally a result of the following:

- \$16 million decrease in operations and maintenance expense primarily related to the following:
- \$36 million decrease primarily as a result of lower project, outage and maintenance expenses; and
- \$8 million decrease relating to reduction in allocated corporate overhead costs as a result of completion of Mirant/RRI Merger integration, partially offset by
- \$30 million in costs to deactivate generating facilities (primarily for an inventory reserve for excess materials and supplies).

California

	Six Months Ended June 30,				Increase/ (Decrease)
	2012	2011	(in millions)		
Gross margin:					
Energy	\$	2	\$	4	\$ (2)

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Contracted and capacity	57	64	(7)
Realized value of hedges	2	2	
Total realized gross margin	61	70	(9)
Unrealized gross margin	(1)	(1)	
Total gross margin (excluding depreciation and amortization)	60	69	(9)
Operating expenses:			
Operations and maintenance	83	78	5
Depreciation and amortization	23	21	2
Total operating expenses, net	106	99	7
Operating loss	\$ (46)	\$ (30)	\$ (16)

Gross Margin

Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for the majority of the capacity from these units, and our Potrero units were subject to RMR arrangements through February 2011. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Therefore, our gross margin generally is not affected by changes in power generation volumes from these facilities.

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For those units that are not under tolling or RMR arrangements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

The decrease of \$9 million in realized gross margin was primarily as a result of the shutdown of the Potrero generating facility in 2011.

Energy Marketing

	Six Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		
Gross margin:			
Energy	\$ 24	\$ 64	\$ (40)
Total realized gross margin	24	64	(40)
Unrealized gross margin	12	(11)	23
Total gross margin (excluding depreciation and amortization)	36	53	(17)
Operating expenses:			
Operations and maintenance	3	2	1
Depreciation and amortization		1	(1)
Total operating expenses, net	3	3	
Operating income	\$ 33	\$ 50	\$ (17)

Gross Margin

The decrease of \$40 million in realized gross margin was primarily as a result of a \$60 million decrease in income from proprietary trading and decreases in fuel oil management activities, partially offset by \$20 million related to the advance settlement of an out-of-market contract obligation.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of \$12 million during the six months ended June 30, 2012, which included a \$9 million net increase in the value of contracts for future periods and \$3 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period; and
- unrealized losses of \$11 million during the six months ended June 30, 2011, which included a \$9 million net decrease in the value of contracts for future periods and \$2 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Table of Contents**Other Operations**

	Six Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		
Gross margin:			
Energy	\$ (5)	\$ 11	\$ (16)
Contracted and capacity	44	48	(4)
Realized value of hedges	(1)	3	(4)
Total realized gross margin	38	62	(24)
Unrealized gross margin	1	(8)	9
Total gross margin (excluding depreciation and amortization)	39	54	(15)
Operating expenses:			
Operations and maintenance	51	85	(34)
Depreciation and amortization	27	28	(1)
Gain on sales of assets, net	(7)	1	(8)
Total operating expenses, net	71	114	(43)
Operating loss	\$ (32)	\$ (60)	\$ 28

Gross Margin

The decrease of \$24 million in realized gross margin was principally a result of a decrease of \$16 million in energy, primarily as a result of decreases in prices.

Operating Expenses

The decrease of \$43 million in operating expenses was principally the result of the following:

- \$34 million decrease in operations and maintenance expense primarily related to a decrease of \$33 million in Mirant/RRI Merger-related costs, primarily for severance; and
- \$8 million increase in gain on sales of assets primarily as a result of the sale of our Indian River generating facility in January 2012.

*Financial Condition***Liquidity and Capital Resources**

Management thinks that our liquidity position and cash flows from operations will be adequate to fund operating, maintenance and capital expenditures, to fund debt service and to meet other liquidity requirements. Management regularly monitors our ability to fund our operating, financing and investing activities. See note 4 to our interim financial statements for additional discussion of our debt.

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Sources of Funds and Capital Structure

The principal sources of our liquidity are expected to be: (a) existing cash on hand and expected cash flows from the operations of our subsidiaries, (b) letters of credit issued or borrowings made under the GenOn senior secured revolving credit facility and (c) letters of credit issued or borrowings made under the GenOn Marsh Landing project financing.

Our operating cash flows may be affected by, among other things: (a) demand for electricity; (b) the difference between the cost of fuel used to generate electricity and the market value of the electricity generated; (c) commodity prices (including prices for electricity, emissions allowances, natural gas, coal and oil); (d) operations and maintenance expenses in the ordinary course; (e) planned and unplanned outages; (f) terms with trade creditors; and (g) cash requirements for capital expenditures relating to certain facilities (including those necessary to comply with environmental regulations).

The table below sets forth total available cash, cash equivalents and availability under credit facilities of GenOn and its subsidiaries at June 30, 2012 (in millions):

Cash and Cash Equivalents:		
GenOn (excluding GenOn Mid-Atlantic and REMA)	\$	1,458
GenOn Mid-Atlantic		200
REMA(1)		19
Total cash and cash equivalents(2)		1,677
Availability under GenOn credit facilities(3)		504
Total available cash, cash equivalents and availability under GenOn credit facilities(2)(3)	\$	2,181

(1) At June 30, 2012, REMA did not satisfy the restricted payments test and therefore could not use such funds to distribute cash and make other restricted payments.

(2) We have \$355 million of collateral deposits from counterparties (including brokers), which are included in accounts payable and accrued liabilities.

(3) Availability under the GenOn credit facilities does not include availability under the GenOn Marsh Landing credit facility.

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At June 30, 2012, except for amounts held in bank accounts to cover upcoming payables, all of our cash and cash equivalents were invested in AAA-rated United States Treasury money market funds and treasury bills.

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We and certain of our subsidiaries, including GenOn Americas Generation, are holding companies. The chart below is a summary representation of our capital structure and is not a complete corporate organizational chart.

(1) The GenOn credit facilities are guaranteed by certain direct and indirect subsidiaries of GenOn excluding GenOn Americas Generation; provided, however, that certain of GenOn Americas Generation's subsidiaries (other than GenOn Mid-Atlantic and GenOn Energy Management, LLC and their subsidiaries) guarantee the GenOn credit facilities to the extent permitted under the indenture for the senior notes of GenOn Americas Generation. GenOn Americas is a co-borrower under the GenOn credit facilities and the term loan balance is recorded at GenOn

Americas.

(2) At June 30, 2012, the present values of lease payments under the GenOn Mid-Atlantic and REMA operating leases were \$826 million and \$469 million, respectively (assuming a 10% and 9.4% discount rate, respectively) and the termination values of the GenOn Mid-Atlantic and REMA operating leases were \$1.2 billion and \$740 million, respectively.

(3) At June 30, 2012, \$79 million and \$176 million were outstanding under the GenOn Marsh Landing senior secured term loan, due 2017 and senior secured term loan, due 2023, respectively.

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Except for existing cash on hand, GenOn and GenOn Americas Generation are holding companies that are dependent on the distributions and dividends of their subsidiaries for liquidity. A substantial portion of cash from our operations is generated by GenOn Mid-Atlantic.

The ability of certain of our subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payments tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At June 30, 2012, GenOn Mid-Atlantic satisfied the restricted payments test. At June 30, 2012, REMA did not satisfy the restricted payments test.

The ability of GenOn Americas Generation to pay its obligations is dependent on the receipt of dividends from GenOn North America and, in turn, GenOn Mid-Atlantic; capital contributions or intercompany loans from GenOn; and its ability to refinance all or a portion of those obligations as they become due.

Uses of Funds

Our requirements for liquidity and capital resources, other than for the day-to-day operation of our generating facilities, are significantly influenced by the following items: (a) capital expenditures, including capital expenditures to meet environmental regulations, (b) debt service, (c) payments under the GenOn Mid-Atlantic and REMA operating leases, (d) collateral required for our asset management and proprietary trading and fuel oil management activities and (e) the development and construction of new generating facilities, in particular the GenOn Marsh Landing generating facility.

Capital Expenditures. Our estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for the period July 1, 2012 through December 31, 2013 will be \$639 million. See *Capital Expenditures and Capital Resources* for further discussion of our capital expenditures.

Cash Collateral and Letters of Credit. In order to sell power and purchase fuel in the forward markets and perform other energy trading and marketing activities, we often are required to provide credit support to our counterparties or make deposits with brokers. In addition, we often are required to provide credit support for various contractual and other obligations incurred in connection with our commercial and operating activities, including obligations in respect of transmission and interconnection access, participation in power pools, rent reserves, power purchases and sales, fuel and emission purchases and sales, construction, equipment purchases and other operating activities. Credit support includes cash collateral, letters of credit, surety bonds and financial guarantees. In the event that we default, the counterparty can draw on a letter of credit or surety bond or apply cash collateral held to satisfy the existing amounts outstanding under an open contract. Our requirements for collateral and, accordingly, liquidity are highly dependent on the level of our hedging activities, forward prices for energy, emissions allowances and fuel, commodity market volatility, credit terms with third parties and regulation of energy contracts.

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At June 30, 2012, we had \$215 million of posted cash collateral and \$284 million of letters of credit outstanding under our revolving credit facility, primarily to support our asset management activities, trading activities, rent reserve requirements, Marsh Landing project and other commercial arrangements. In addition, we issued \$85 million of cash-collateralized letters of credit in support of the Marsh Landing project and delivered \$48 million of surety bonds to satisfy various other credit support agreements.

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The following table summarizes cash collateral posted with counterparties and brokers, letters of credit issued and surety bonds provided:

	June 30, 2012	December 31, 2011
	(in millions)	
Cash collateral posted energy trading and marketing	\$ 153	\$ 185
Cash collateral posted other operating activities	62	39
Letters of credit rent reserves	173	130
Letters of credit Marsh Landing project(1)	129	175
Letters of credit energy trading and marketing	54	59
Letters of credit other operating activities	13	32
Surety bonds(2)	48	46
Total	\$ 632	\$ 666

(1) Includes \$85 million and \$131 million of cash-collateralized letters of credit at June 30, 2012 and December 31, 2011, respectively.

(2) Includes \$34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at June 30, 2012 and December 31, 2011.

Restricted Payments Limitations. The GenOn credit agreement and indenture for the senior notes due 2018 and 2020 restrict the ability of GenOn to make restricted payments, including dividends and purchases of capital stock. At June 30, 2012, GenOn did not meet the consolidated debt ratio component of the restricted payments test in the indenture and, therefore, the ability of GenOn to make restricted payments is limited to specified exclusions from the covenant, including up to \$250 million of such restricted payments.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

There have been no material changes outside the ordinary course of business to our debt obligations, off-balance sheet arrangements and contractual obligations from those disclosed in our 2011 Annual Report on Form 10-K and note 4 to our interim financial statements.

Historical Cash Flows

	Six Months Ended June 30,		Increase/ (Decrease)
	2012	2011	
	(in millions)		
Net cash provided by operating activities	\$ 28	\$ 15	\$ 13
Net cash provided by (used in) investing activities	(161)	1,247	(1,408)
Net cash provided by (used in) financing activities	142	(2,062)	2,204

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Operating Activities. Our cash provided by operating activities is affected by seasonality, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by operating activities before changes in operating assets and liabilities decreased \$80 million for the six months ended June 30, 2012, compared to the same period in 2011, primarily resulting from higher net loss, adjusted for non-cash items, in 2012. Changes in our cash flows from operating activities before changes in operating assets and liabilities were generally consistent with changes in our results of operations, adjusted for non-cash items. See *Results of Operations* for additional information related to our performance in 2012 as compared to the same period in 2011.

Operating assets and liabilities increased cash by \$93 million primarily as a result of the following:

- *Accounts payable, collateral.* An increase in cash provided of \$225 million as a result of \$227 million posted by our counterparties in 2012 compared to \$2 million posted by our counterparties in 2011 primarily resulting from a contract modification in April 2012 to require a counterparty to post cash collateral to secure credit exposure above an agreed threshold as a result of changes in power or natural gas prices; and

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- *Funds on deposit.* An increase in cash provided of \$154 million primarily as a result of \$55 million of additional collateral returned from our counterparties in 2012 compared to \$99 million of additional collateral posted in 2011.

The increases in cash provided by operating activities were partially offset by the following:

- *Net receivables and accounts payable and accrued liabilities.* A decrease in cash provided of \$131 million primarily as a result of a decrease in receivables in 2011 partially offset by higher volume of settlements of power hedges in 2011 as compared to the same period in 2012;
- *Inventories.* An increase in cash used of \$68 million primarily related to changes in fuel oil and coal inventory and purchased emissions allowances;
- *Income taxes.* An increase in cash used of \$17 million primarily as a result of income tax settlements; and
- *Taxes other than income taxes.* An increase in cash used of \$19 million primarily as a result of property tax payments.

Investing Activities. Net cash provided by/used in investing activities changed by \$1.408 billion for the six months ended June 30, 2012, compared to the same period in 2011. This difference was primarily a result of the following:

- *Restricted funds on deposit debt financing.* A decrease in cash provided of \$1.561 billion primarily related to funds received from the GenOn debt financing on December 3, 2010, which were subsequently placed in restricted deposits at December 31, 2010 and withdrawn to repay long-term debt during 2011; and
- *Capital expenditures.* An increase in cash used of \$159 million primarily related to a \$107.1 million payment in connection with the scrubber contract litigation settlement in 2012 and construction of our Marsh Landing generating facility; partially offset by
- *Restricted funds on deposit liens under scrubber contract litigation.* A change in cash of \$309 million primarily related to \$143 million of funds placed in restricted deposits in 2011 as a result of the scrubber contract litigation and related liens and \$165.6 million of those same liens released in 2012 in connection with the settlement.

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Financing Activities. Net cash provided by/used in financing activities changed by \$2.204 billion for the six months ended June 30, 2012, compared to the same period in 2011. This difference was primarily a result of the following:

- *Repayment of long-term debt.* A decrease in cash used of \$2.066 billion primarily related to repayment during 2011 of GenOn senior secured notes, GenOn Americas Generation senior unsecured notes, GenOn North America senior unsecured notes and PEDFA bonds; and
- *Proceeds from long-term debt.* An increase in cash provided of \$139 million related to proceeds received to finance the construction of our Marsh Landing generating facility.

Critical Accounting Estimates

See Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Estimates, in Item 7 in our 2011 Annual Report on Form 10-K.

Recently Adopted Accounting Guidance

See note 1 to our interim financial statements for further information related to our recently adopted accounting guidance.

Table of Contents**ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

See Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2011 Annual Report on Form 10-K and notes 1 and 3 to our interim financial statements.

Fair Value Measurements

The following tables provide a summary of the factors affecting changes (composed of the sum of the quarterly changes) in fair value of the derivative contract asset and liability accounts for the six months ended June 30, 2012 and 2011:

	Commodity Contracts		Other Contracts		Total
	Asset Management	Trading	Interest Rate	(in millions)	
Fair value of portfolio of assets and liabilities at January 1, 2012	\$ 916	\$ (3)	\$ (32)	\$ 881	
Gains (losses) recognized in the period, net:					
New contracts and other changes in fair value(1)	182	4	(13)	173	
Purchases(2)					
Issuances(2)					
Settlements(3)	(228)	2	1	(225)	
Fair value of portfolio of assets and liabilities at June 30, 2012	\$ 870	\$ 3	\$ (44)	\$ 829	
Fair value of portfolio of assets and liabilities at January 1, 2011	\$ 706	\$ (5)	\$ 19	\$ 720	
Gains (losses) recognized in the period, net:					
New contracts and other changes in fair value(1)	32	(5)	(11)	16	
Purchases(2)					
Issuances(2)					
Settlements(3)	(123)	(4)		(127)	
Fair value of portfolio of assets and liabilities at June 30, 2011	\$ 615	\$ (14)	\$ 8	\$ 609	

(1) Represents the fair value, as of the end of each reporting period, of contracts entered into during each reporting period and the gains or losses attributable to contracts that existed as of the beginning of each reporting period and were still held at the end of each reporting period.

(2) Contracts entered into during each reporting period are reported with other changes in fair value.

(3) Represents the reversal of previously recognized unrealized gains and losses from the settlement of contracts during each reporting period.

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At June 30, 2012, the estimated net fair value of our derivative contract assets and liabilities are (asset (liability)):

Sources of Fair Value	Remainder of 2012	2013	2014	2015 (in millions)	2016	2017 and thereafter	Total fair value
<u>Asset Management:</u>							
Prices actively quoted (Level 1)	\$ (12)	\$ 14	\$ 12	\$ 24	\$ 51	\$	\$ 89
Prices provided by other external sources (Level 2)	199	391	288	55			933
Prices based on models and other valuation methods (Level 3)	(87)	(55)	(10)				(152)
Total asset management	\$ 100	\$ 350	\$ 290	\$ 79	\$ 51	\$	\$ 870
<u>Trading Activities:</u>							
Prices actively quoted (Level 1)	\$ (7)	\$	\$	\$	\$	\$	\$ (7)
Prices provided by other external sources (Level 2)	(6)	(5)					(11)
Prices based on models and other valuation methods (Level 3)	15	6					21
Total trading activities	\$ 2	\$ 1	\$	\$	\$	\$	\$ 3
<u>Interest Rate:</u>							
Prices actively quoted (Level 1)	\$	\$	\$	\$	\$	\$	\$
Prices provided by other external sources (Level 2)	(1)	(8)	(12)	(9)	(6)	(8)	(44)
Prices based on models and other valuation methods (Level 3)							
Total interest rate	\$ (1)	\$ (8)	\$ (12)	\$ (9)	\$ (6)	\$ (8)	\$ (44)

The fair values shown in the table above are subject to significant changes as a result of fluctuating commodity forward market prices, volatilities and credit risk. For further discussion of how we determine these fair values, see note 3 to our interim financial statements.

Commodity Price Risk

In connection with our business of generating electricity, we are exposed to energy commodity price risk associated with the acquisition of fuel and emissions allowances needed to generate electricity, the price of electricity produced and sold and the fair value of our fuel inventories. A portion of our fuel requirements is purchased in the spot market and a portion of the electricity we produce is sold in the spot market. In addition, the open positions in our proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

The financial performance of our business of generating electricity is influenced by the difference between the variable cost of converting a fuel, such as natural gas, coal or oil, into electricity, and the variable revenue we receive from the sale of that electricity. The difference between the cost of a specific fuel used to generate one MWh of electricity and the market value of the electricity generated is commonly referred to as the conversion

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spread. Absent the effects of our derivative contract activities, the operating margins that we realize are equal to the difference between the aggregate conversion spread and the cost of operating the facilities that produce the electricity sold.

Conversion spreads are dependent on a variety of factors that influence the cost of fuel and the sales price of the electricity generated over the longer term, including conversion spreads of other generating facilities in the regions in which we operate, facility outages, weather and general economic conditions. As a result of these influences, the cost of fuel and electricity prices do not always change in the same magnitude or direction, which results in conversion spreads for a particular generating facility widening or narrowing (or becoming negative) over any given period.

Through our asset management activities, we enter into a variety of exchange-traded and OTC energy and energy-related derivative financial instruments, such as forward contracts, futures contracts, option contracts and financial swap agreements, to manage our exposure to commodity price risks. These contracts have varying terms and durations, which range from a few days to years, depending on the instrument. Our proprietary trading activities also utilize similar derivative contracts in markets where we have a physical presence to attempt to generate incremental gross margin. Our fuel oil management activities use derivative financial instruments to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately two million barrels of storage capacity that we own, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products.

Counterparty Credit Risk

We are exposed to the default risk of the counterparties with which we transact. We manage our credit risk by entering into master netting agreements and requiring most counterparties to post cash collateral or other credit enhancements based on the net exposure and the credit standing of the counterparty. An increase of 10% in the spread of credit default swaps of our trading partners would result in an increase of \$2 million in our credit valuation adjustment at June 30, 2012. See note 3 to our interim financial statements.

ITEM 4. CONTROLS AND PROCEDURES

Effectiveness of Disclosure Controls and Procedures

As required by Exchange Act Rule 13a-15(b), our management, including our Chief Executive Officer and our Chief Financial Officer, conducted an assessment of the effectiveness of the design and operation of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of June 30, 2012. Based upon this assessment, our management concluded that, as of June 30, 2012, the design and operation of these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

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There have been no changes in our internal controls over financial reporting that have occurred during the quarter ended June 30, 2012 that have materially affected or are reasonably likely to materially affect the internal controls over financial reporting.

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**PART II
OTHER INFORMATION**

ITEM 1. LEGAL PROCEEDINGS

See note 10 to our interim financial statements.

ITEM 1A. RISK FACTORS

Failure to complete our merger with NRG could negatively affect our future business and financial results.

On July 22, 2012, we announced the execution of the NRG Merger Agreement with NRG. Before the NRG Merger may be completed, the parties must satisfy all conditions set forth in the NRG Merger Agreement, including, among other things, obtaining approvals by stockholders of both companies, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and obtaining approvals from various state and federal regulatory and governmental authorities (or such authorities' determinations that no such approval is required). These authorities may impose conditions on the completion, or require changes to the terms, of the NRG Merger. These conditions or changes could have the effect of delaying completion of the NRG Merger or imposing additional costs on or limiting the revenues of the combined company following the NRG Merger. Satisfying the conditions to and completion of the NRG Merger may take longer than expected and could cost more than we expect. We cannot make any assurances that we will be able to satisfy all the conditions to the NRG Merger or succeed in any litigation brought in connection with the NRG Merger.

If the NRG Merger is not completed, our financial results may be adversely affected because we still will be required to pay costs relating to the NRG Merger, including legal, accounting, financial advisory, filing and printing costs. Also, under circumstances specified in the NRG Merger Agreement, we may be required to pay NRG a termination fee of \$60 million. We could also be subject to litigation related to any failure to complete the NRG Merger. Furthermore, purported class actions have been brought on behalf of holders of our common stock. If these actions or similar actions that may be brought are successful, the NRG Merger could be delayed or prevented. See note 10 to our interim financial statements for discussion of pending litigation related to the NRG Merger.

If completed, our merger with NRG may not achieve its intended results.

We entered into the NRG Merger Agreement with the expectation that the NRG Merger would result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the NRG Merger is subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs and decreases in the amount of expected revenues generated by the combined company.

We will be subject to various uncertainties and contractual restrictions while the NRG Merger is pending that could adversely affect our financial results.

Uncertainty about the effect of the NRG Merger on employees, customers, suppliers and others may have an adverse effect on our business. These uncertainties may impair our ability to attract, retain and motivate key personnel until the NRG Merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the NRG Merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company.

The pursuit of the NRG Merger and the preparation for the integration of the companies may place a significant burden on our management and internal resources. Any significant diversion of management attention away from ongoing business and any difficulties encountered in the NRG Merger integration process could adversely affect our business, results of operations and financial condition.

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In addition, the NRG Merger Agreement restricts us, without NRG's consent, from making certain acquisitions and dispositions and taking other specified actions. These restrictions may prevent us from pursuing attractive business opportunities and making other changes to our business prior to completion of the NRG Merger or termination of the NRG Merger Agreement.

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ITEM 6. EXHIBITS

Exhibit No.	Exhibit Name
2.1**	Agreement and Plan of Merger, dated as of July 20, 2012, by and among NRG Energy, Inc., Plus Energy Corporation and GenOn Energy, Inc. (Incorporated herein by reference to Exhibit 2.1 to the Registrant's Form 8-K filed July 23, 2012)
3.1	Third Restated Certificate of Incorporation of Registrant (Incorporated herein by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q filed August 2, 2007)
3.2	Certificate of Amendment to the Third Restated Certificate of Incorporation of Registrant, dated at December 3, 2010 (Incorporated herein by reference to Exhibit 4.1 to the Registrant's Form S-8 filed December 3, 2010)
3.3	Certificate of Amendment to the Third Restated Certificate of Incorporation of Registrant, dated May 5, 2011 (Incorporated herein by reference to Exhibit 3.1 to the Registrant's Form 8-K filed May 9, 2011)
3.4	Seventh Amended and Restated Bylaws of Registrant, dated at December 3, 2010 (Incorporated herein by reference to Exhibit 4.2 to the Registrant's Form S-8 filed with the Securities and Exchange Commission on December 3, 2010)
10.1*	Form of 2012 Restricted Stock Unit Award Agreement for Directors under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan
10.2*	GenOn Energy, Inc. Severance Pay Plan effective as of December 3, 2010, as amended and restated June 1, 2012
31.1*	Certification of the Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a))
31.2*	Certification of the Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a))
32.1*	Certification of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
32.2*	Certification of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
101*	Interactive Data File

* Asterisk indicates exhibits filed herewith.

** This filing excludes schedules and exhibits pursuant to Item 601(b)(2) of Regulation S-K, which the registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request by the Commission.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GENON ENERGY, INC.

Date: August 9, 2012

By:

/s/ THOMAS C. LIVENGOOD
Thomas C. Livengood
Senior Vice President and Controller
(Duly Authorized Officer and Principal Accounting Officer)