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

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2012

OR

o 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	**76-0655566**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1000 Main Street, Houston, Texas	**77002**
(Address of Principal Executive Offices)	(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. x Yes o 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). x Yes o 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 x	Accelerated Filer o
Non-accelerated Filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of May 3, 2012, there were 772,866,179 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.
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, mothball 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 Merger.
GenOn Americas	GenOn Americas, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC.
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.

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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.
Merger	the merger completed on December 3, 2010 pursuant to the Merger Agreement.
Merger Agreement	the agreement by and among Mirant Corporation, RRI Energy, Inc. and RRI Energy Holdings, Inc. dated as of April 11, 2010.
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
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.

net generating capacity	net summer capacity.
NJDEP	New Jersey Department of Environmental Protection.
NOL	net operating loss.
NOV	notice of violation.

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NO_x	nitrogen oxides.
NPDES	national pollutant discharge elimination system.
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 Merger.
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.
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, thin 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;

- 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 Section 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; and

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

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.

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 March 31, 2012	2011
	(in millions, except per share data)	
Operating revenues (including unrealized gains (losses) of $143 and $(99), respectively)	$ 721	$ 814
Cost of fuel, electricity and other products (including unrealized (gains) losses of $43 and $(20), respectively)	278	401
Gross Margin (excluding depreciation and amortization)	443	413
Operating Expenses:		
Operations and maintenance	308	305
Depreciation and amortization	88	86
Gain on sales of assets, net	(8)	(1)
Total operating expenses	388	390
Operating Income	55	23
Other Income (Expense), net:		
Interest expense	(89)	(109)
Other, net	2	(22)
Total other expense, net	(87)	(131)
Loss Before Income Taxes	(32)	(108)
Provision for income taxes		3
Net Loss	$ (32)	$ (111)
Basic and Diluted EPS:		
Basic EPS	$ (0.04)	$ (0.14)
Diluted EPS	$ (0.04)	$ (0.14)
Weighted average shares outstanding	774	771
Effect of dilutive securities		
Weighted average shares outstanding assuming dilution	774	771

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 STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(UNAUDITED)

	Three Months Ended March 31, 2012	2011
	(in millions)	
Net Loss	$ (32)	$ (111)
Other Comprehensive Income (Loss), net of reclassifications to net loss, net of tax of $0:		
Pension and other postretirement benefits actuarial losses, net	2	1
Pension and other postretirement benefits prior service credit, net	(1)	(1)
Cash flow hedges interest rate swaps	4	3
Available-for-sale securities		(1)
Other Comprehensive Income	5	2
Comprehensive Loss	$ (27)	$ (109)

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)

	March 31, 2012	December 31, 2011
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,705	$ 1,668
Funds on deposit	427	422
Receivables, net	299	357
Derivative contract assets	1,231	999
Inventories	532	563
Prepaid rent and other expenses	158	167
Total current assets	4,352	4,176
Property, plant and equipment, gross	7,451	7,351
Accumulated depreciation and amortization	(1,219)	(1,160)
Property, Plant and Equipment, net	6,232	6,191
Noncurrent Assets:		
Intangible assets, net	46	48
Derivative contract assets	820	733
Deferred income taxes	337	294
Prepaid rent	362	386
Other	438	441
Total noncurrent assets	2,003	1,902
Total Assets	$ 12,587	$ 12,269
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 10	$ 10
Accounts payable and accrued liabilities	881	790
Derivative contract liabilities	892	720
Deferred income taxes	337	294
Other	125	130
Total current liabilities	2,245	1,944
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,165	4,122
Derivative contract liabilities	177	131
Pension and postretirement obligations	255	259
Other	653	696
Total noncurrent liabilities	5,250	5,208
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at March 31, 2012 and December 31, 2011		
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 772,487,968 shares and 771,692,734 shares at March 31, 2012 and December 31, 2011, respectively	1	1
Additional paid-in capital	7,451	7,449
Accumulated deficit	(2,195)	(2,163)
Accumulated other comprehensive loss	(165)	(170)
Total stockholders equity	5,092	5,117
Total Liabilities and Stockholders Equity	$ 12,587	$ 12,269

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 STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2012	2011
	(in millions)	
Cash Flows from Operating Activities:		
Net loss	$ (32)	$ (111)
Adjustments to reconcile net loss and changes in operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	92	90
Amortization of acquired contracts	(8)	(7)
Gain on sales of assets, net	(8)	(1)
Net changes in derivative contracts	(100)	79
Stock-based compensation expense	3	3
Excess materials and supplies inventory reserve	35	
Lower of cost or market inventory adjustments	46	
Loss on early extinguishment of debt.		24
Advance settlement of out-of-market contract obligation	(20)	
Other, net	2	
Changes in operating assets and liabilities	57	141
Total adjustments	99	329
Net cash provided by operating activities	67	218
Cash Flows from Investing Activities:		
Capital expenditures	(87)	(98)
Proceeds from the sales of assets	12	1
Restricted funds on deposit, net	2	1,020
Net cash provided by (used in) investing activities	(73)	923
Cash Flows from Financing Activities:		
Proceeds from long-term debt	45	
Repayment of long-term debt	(2)	(1,153)
Net cash provided by (used in) financing activities	43	(1,153)
Net Increase (Decrease) in Cash and Cash Equivalents	37	(12)
Cash and Cash Equivalents, beginning of period	1,668	2,402
Cash and Cash Equivalents, end of period	$ 1,705	$ 2,390
Supplemental Disclosures:		
Cash paid for interest, net of amounts capitalized	$ 11	$ 16
Cash refunds received for income taxes	$ 2	$ 5

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 23,700 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 we 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 contex indicates otherwise, its subsidiaries, after giving effect to the Merger.

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 December 31, 2011 and March 31, 2012, 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.

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;
- 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.

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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 months ended March 31, 2011 have been retroactively amended for the revisions to the provisional purchase price allocation in connection with the 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 Merger. Based on further inquiries, we do not think that RRI Energy experienced an ownership change as a result of the Merger or following the 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:

	March 31, 2012	December 31, 2011
	(in millions)	
Cash collateral posted energy trading and marketing	$ 171	$ 185
Cash collateral posted other operating activities(1)	59	39
Cash collateral posted surety bonds(2)	34	34
GenOn Mid-Atlantic restricted cash(3)	166	166
GenOn Marsh Landing development project cash collateral posted(4)	114	131
Environmental compliance deposits(5)	35	34
Other	14	16
Total current and noncurrent funds on deposit	593	605
Less: Current funds on deposit	427	422
Total noncurrent funds on deposit	$ 166	$ 183

(1) Includes $32 million related to the Potomac River settlement. See note 2.

(2) Represents cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations.

(3) Represents cash reserved in respect of interlocutory liens related to the scrubber contract litigation. See note 10.

(4) Represents cash-collateralized letters of credit to support the Marsh Landing development project.

(5) 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.

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Inventories

Inventories were comprised of the following:

	March 31, 2012	December 31, 2011
	(in millions)	
Fuel inventory:		
Coal	$ 229	$ 229
Fuel oil	102	108
Natural gas		1
Other	5	5
Materials and supplies(1)	164	201
Purchased emissions allowances	32	19
Total inventories	$ 532	$ 563

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

During the three months ended March 31, 2012 and 2011, we recorded $46 million and $0, 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 March 31, 2012	Three Months Ended March 31, 2011
	(in millions)	
Total interest costs	$ 96	$ 111
Capitalized and included in property, plant and equipment, net	(7)	(2)
Interest expense	$ 89	$ 109

The amounts of capitalized interest above include interest accrued. During the three months ended March 31, 2012 and 2011, cash paid for interest was $16 million and $17 million, respectively, of which $5 million and $1 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.

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 $56 million at March 31, 2012 and $4 million is recorded in the consolidated balance sheet for this item.

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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 March 31, 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 currently expect to deactivate the following generating capacity, primarily coal-fired units, at the referenced times: Niles unit 2 (108 MW) June 2012, Elrama units 1-3 (289 MW) mothball June 2012 and 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 will operate Niles unit 1 (109 MW) and Elrama unit 4 (171 MW) under RMR arrangements until October 1, 2012 whereupon we expect to deactivate those two units in the same manner as the other units at those facilities. While we continue to work with PJM to ensure that any reliability concerns that PJM may have regarding these deactivations are addressed, based on our discussions with PJM, we think that the units identified above for deactivation will be deactivated at the times referenced.

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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 receipt of all necessary consents and approvals. PJM has determined that the retirement of the facility will not affect reliability. We must now receive consent from PEPCO. We will reverse $31 million of the previously recorded obligation under the 2008 agreement with the City of Alexandria upon the receipt of consent from PEPCO and we will recognize a reduction in operations and maintenance expense. If the PEPCO consent has not been received by July 3, 2012, the Potomac River generating facility will be retired within 90 days after the receipt thereof. Upon retirement of the Potomac River generating facility, all funds in the escrow account ($32 million) established under the July 2008 agreement shall be distributed to us, provided, that, if the retirement of the facility is after January 1, 2014, $750,000 of such funds shall be paid to the City of Alexandria.

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 Related to Deactivations

In connection with our decision to deactivate the generating facilities, we are evaluating our materials and supplies inventory and have 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. At March 31, 2012, the aggregate carrying value of property, plant and equipment and materials and supplies inventory for the ten generating facilities to be deactivated was $194 million and $26 million, respectively. In addition, we expect to incur other costs in connection with the deactivations, such as severance and 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 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.

If certain criteria are met, a derivative financial instrument may be designated as a fair value hedge or cash flow hedge. In the fourth quarter of 2010, GenOn Marsh Landing entered into interest rate protection agreements

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(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 three months ended March 31, 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
	Current	Long-Term	Current	Long-Term	Assets (Liabilities)
			(in millions)		
March 31, 2012					
Commodity Contracts:					
Asset management	$ 694	$ 811	$ (344)	$ (139)	$ 1,022
Trading activities	537	9	(546)	(10)	(10)
Total commodity contracts	1,231	820	(890)	(149)	1,012
Interest Rate Contracts			(2)	(28)	(30)
Total derivatives	$ 1,231	$ 820	$ (892)	$ (177)	$ 982
December 31, 2011					
Commodity Contracts:					
Asset management	$ 538	$ 730	$ (255)	$ (97)	$ 916
Trading activities	461	3	(464)	(3)	(3)
Total commodity contracts	999	733	(719)	(100)	913
Interest Rate Contracts			(1)	(31)	(32)
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:

	Three Months Ended March 31,			
	2012		2011	
Derivatives Not Designated as Hedging Instruments	Operating Revenues	Cost of Fuel, Electricity and Other Products	Operating Revenues	Cost of Fuel, Electricity and Other Products
		(in millions)		
Asset Management Commodity Contracts:				
Unrealized	$ 150	$ (43)	$ (75)	$ 20
Realized(1)(2)	184	(16)	79	(43)
Total asset management	$ 334	$ (59)	$ 4	$ (23)
Trading Commodity Contracts:				
Unrealized	$ (7)	$	$ (24)	$
Realized(1)(2)	(5)		6	
Total trading	$ (12)	$	$ (18)	$
Total derivatives	$ 322	$ (59)	$ (14)	$ (23)

(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.

We recognized immaterial amounts in earnings on derivatives for the interest rate swaps classified as cash flow hedges for the three months ended March 31, 2012 and 2011. These amounts represent the ineffective portion of the interest rate swaps and are recorded in interest expense. The assessment of effectiveness excludes the default risk of the counterparties to these transactions and our own non-performance risk. The effect of these valuation adjustments, which is recorded in interest expense, is a loss of $2 million and a loss of an immaterial amount during

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the three months ended March 31, 2012 and 2011, respectively. At March 31, 2012, no cash flow hedges were discontinued and no amount was recognized in our results of operations as a result of discontinued cash flow hedges as all of the forecasted transactions (future interest payments) were deemed probable of occurring.

At March 31, 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.

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

	Notional Volumes at March 31, 2012		
Derivative Instruments	**Derivative Contract Assets**	**Derivative Contract Liabilities**	**Net Derivative Contracts**
		(in millions)	
Commodity Contracts (in equivalent MWh):			
Power(1)	(119)	63	(56)
Natural gas	(7)	9	2
Coal	1	12	13
Interest Rate Contracts (in dollars)(2)		475	475

	Notional Volumes at December 31, 2011		
Derivative Instruments	**Derivative Contract Assets**	**Derivative Contract Liabilities**	**Net Derivative Contracts**
		(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:

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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.

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 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 March 31, 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

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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 March 31, 2012, the assets and liabilities classified as Level 3 in the fair value hierarchy represented 5% of total derivative contract assets and 14% 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.

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/short position in isolation would result in a higher/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. A strong, effective reporting and monitoring function, which includes daily and weekly reporting, keeps the ROC and Chief Risk Officer informed of our 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:

	March 31, 2012			
	Level 1(1)	Level 2(1)(2)	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 143	$ 1,321	$ 35	$ 1,499
Fuel		1	5	6
Total Asset Management	143	1,322	40	1,505
Trading Activities	90	388	68	546
Total derivative contract assets	$ 233	$ 1,710	$ 108	$ 2,051
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 69	$ 276	$ 1	$ 346
Fuel	16	2	119	137
Total Asset Management	85	278	120	483
Trading Activities	110	422	24	556
Interest Rate Contracts		30		30
Total derivative contract liabilities	$ 195	$ 730	$ 144	$ 1,069
Interest-bearing funds(3)	$ 1,994	$	$	$ 1,994
Other assets(4)	$ 21	$	$	$ 21

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no transfers during the three months ended March 31, 2012.

(2) Option contracts comprised 2% of net derivative contract assets.

(3) 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. We had $1.655 billion of interest-bearing funds included in cash and cash equivalents, $200 million included in funds on deposit and $139 million included in other noncurrent assets.

(4) 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			
	Level 1(1)	Level 2(1)(2)	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 102	$ 1,136	$ 19	$ 1,257
Fuel	2		9	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	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(3)	$ 1,985	$	$	$ 1,985
Other assets(4)	$ 20	$	$	$ 20

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(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) 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. We had $1.626 billion of interest-bearing funds included in cash and cash equivalents, $202 million included in funds on deposit and $157 million included in other noncurrent assets.

(4) 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 three months ended March 31, 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)	(40)	29	(11)
Purchases(2)			
Issuances(2)			
Settlements(3)	13	(7)	6
Transfers into Level 3(4)			
Transfers out of Level 3(4)			
Balance, March 31, 2012 (net asset (liability))	$ (80)	$ 44	$ (36)
Balance, January 1, 2011 (net asset (liability))	$ (70)	$ 2	$ (68)
Total gains (losses) realized/unrealized:			
Included in earnings (1)	23	1	24
Purchases(2)			
Issuances(2)			
Settlements(3)	(4)		(4)
Transfers into Level 3(4)			
Transfers out of Level 3(4)			
Balance, March 31, 2011 (net asset (liability))	$ (51)	$ 3	$ (48)

(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:

	Three Months Ended March 31,	
	2012	2011
	Total	Total

	Operating Revenues	**Cost of Fuel, Electricity and Other Products**		**Operating Revenues**	**Cost of Fuel, Electricity and Other Products**	
			(in millions)			
Gains (losses) included in income	$ 39	$ (44)	$ (5)	$ 4	$ 16	$ 20
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 March 31	$ 38	$ (43)	$ (5)	$ 4	$ 15	$ 19

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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:

	Quantitative Information about Level 3 Fair Value Measurements					
	Net Fair Value at March 31, 2012 (in millions)		Valuation Techniques	Unobservable Input	Range (Weighted Average)(1)	
Power swaps	$	6	Internal model	Market price	3% to (3)%	(2)
Spread options	$	8	Internal model	Volatility	35% to (28)%	(3)
Credit valuation adjustment	$	(1)	Internal model	Counterparty credit risk	20% to (20)%	(4)
Credit valuation adjustment	$	3	Internal model	Own credit risk	20% to (20)%	(4)

(1) Excludes immaterial unobservable inputs related to power transmission congestion products and premiums on physical gas transactions.

(2) Represents the range of the market curves used in the valuation analysis that we think market participants might use when pricing the contracts.

(3) Represents the range of the volatility curves used in the valuation analysis that we think market participants might use when pricing the contracts.

(4) 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 March 31, 2012, net fair value of $63 million of power transactions and $(115) million of 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 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 unsecured obligations of GenOn Mid-Atlantic and the counterparties and do not require either party to post cash collateral for initial margin and, except as described in the next sentence, changes in power or natural gas prices. Beginning in April 2012, certain agreements entered into by GenOn Mid-Atlantic were amended to provide for the counterparty thereto to post collateral to secure credit exposure above the agreed threshold as a result of changes in power or natural gas prices. Our credit valuation adjustment on derivative contract assets was $24 million and $48 million at March 31, 2012 and December 31, 2011, respectively.

At March 31, 2012 and December 31, 2011, $3 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.

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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:

	March 31, 2012				
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3) (dollars in millions)	Exposure Net of Collateral	% of Net Exposure
Clearing and Exchange	$ 906	$ 298	$ 298	$	
Investment Grade:					
Financial institutions	902	858		858	78%
Energy companies	511	211	1	210	19%
Non-investment Grade:					
Energy companies	12	7	3	4	
No External Ratings:					
Internally-rated investment grade	23	22		22	2%
Internally-rated non-investment grade	9	9		9	1%
Total	$ 2,363	$ 1,405	$ 302	$ 1,103	100%

	December 31, 2011				
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3) (dollars in millions)	Exposure Net of Collateral	% of Net Exposure
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.

We had credit exposure to two investment grade counterparties at March 31, 2012 and December 31, 2011, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling $669 million and $664 million at March 31, 2012 and December 31, 2011, respectively. In April 2012, certain agreements entered into by GenOn Mid-Atlantic were amended to provide for the counterparty thereto to post collateral to secure credit exposure above the agreed threshold as a result of changes in power or natural gas prices, including one of the counterparties referenced in the preceding sentence. At April 27, 2012, the total credit exposure, net of collateral, of the referenced counterparty was $201 million compared to $429 million at March 31, 2012.

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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 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 March 31, 2012, the fair value of financial instruments with credit-risk-related contingent features in a net liability position was $11 million for which we had posted collateral of $9 million, including cash and letters of credit.

At March 31, 2012 and December 31, 2011, we had $104 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
March 31, 2012					
Liabilities:					
Long and short-term debt	$ 4,175	$	$ 3,746	$ 139	$ 3,885
December 31, 2011					
Liabilities:	$ 4,132	$	$ 3,969	$ 97	$ 4,066
Long and short-term debt					

(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:

	March 31, 2012			December 31, 2011		
	Weighted Average Stated Interest Rate (1)	Long-term	Current	Weighted Average Stated Interest Rate (1)	Long-term	Current
	(in millions, except interest rates)					
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	683	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		(24)	(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	2.78	47		2.76	33	
Senior secured term loan, due 2023	3.03	105		3.01	74	
Other:						
Capital leases, due 2012 to 2015	7.375-8.19	13	5	7.375-8.19	14	5
Adjustment to fair value of debt(3)		(32)			(32)	
Total		$ 4,165	$ 10		$ 4,122	$ 10

(1) The weighted average stated interest rates are at March 31, 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 Merger was adjusted to fair value on the Merger date. Included in interest expense is amortization of $0 and $1 million for valuation adjustments related to the assumed debt for the three months ended March 31, 2012 and 2011, respectively.

GenOn Credit Facilities

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At March 31, 2012, outstanding letters of credit were $256 million and availability of borrowings under the revolving credit facility was $532 million.

5. Pension and Other Postretirement Benefit Plans

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

	Pension Plans Three Months Ended March 31, 2012	Pension Plans Three Months Ended March 31, 2011	Other Postretirement Benefit Plans Three Months Ended March 31, 2012	Other Postretirement Benefit Plans Three Months Ended March 31, 2011
	(in millions)			
Service cost	$ 3	$ 3	$	$
Interest cost	6	6	1	1
Expected return of plan assets	(7)	(8)		
Net amortization(1)	2	1	(1)	(1)
Net periodic benefit cost	$ 4	$ 2	$	$

(1) Net amortization amount includes prior service cost or credit and actuarial losses or gains.

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6. Stock-Based Compensation

Compensation expense for the stock-based incentive plan was:

	Three Months Ended March 31, 2012	2011
	(in millions)	
Stock-based incentive plan compensation expense (pre-tax) (1)	$ 3	$ 3

(1) No tax benefits related to stock-based compensation were realized during the three months ended March 31, 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

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.

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

	Three Months Ended March 31, 2012	2011
	(in millions, except per share data)	

Net loss	$	(32)	$	(111)
Basic and diluted shares				
Weighted average shares outstanding basic		774		771
Shares from assumed vesting of restricted stock units(1)				
Weighted average shares outstanding diluted		774		771
Basic and Diluted EPS				
Basic EPS	$	(0.04)	$	(0.14)
Diluted EPS	$	(0.04)	$	(0.14)

(1) As we incurred a net loss for the three months ended March 31, 2012 and 2011, diluted loss per share is calculated the same as basic loss per share.

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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 March 31, 2012	2011
	(in millions)	
Stock options	16	19
Restricted stock units	6	3
Total number of antidilutive shares	22	22

8. Accumulated Other Comprehensive Loss

The component balances of accumulated other comprehensive loss and changes during the periods are as follows:

	Pension and Other Postretirement Benefits Actuarial Losses, net	Pension and Other Postretirement Benefits Prior Service Credit, net	Cash Flow Hedges Interest Rate Swaps (in millions)	Other, net	Total Accumulated Other Comprehensive Loss
Balance December 31, 2011	$ (142)	$ 7	$ (34)	$ (1)	$ (170)
Unrealized gains, net of tax of $0			4		4
Reclassifications to net loss, net of tax of $0	2	(1)			1
Balance March 31, 2012	$ (140)	$ 6	$ (30)	$ (1)	$ (165)

	Pension and Other Postretirement Benefits Actuarial Losses, net	Pension and Other Postretirement Benefits Prior Service Credit, net	Cash Flow Hedges Interest Rate Swaps (in millions)	Available-for-Sale Securities	Other, net	Total Accumulated Other Comprehensive Loss
Balance December 31, 2010	$ (57)	$ 11	$ 21	$ 1	$ (1)	$ (25)
Unrealized gains (losses), net of tax of $0			3	(1)		2
Reclassifications to net loss, net of tax of $0	1	(1)				
Balance March 31, 2011	$ (56)	$ 10	$ 24	$	$ (1)	$ (23)

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.

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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 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 7,483 MW. 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 of 362 MW, which was shut down on February 28, 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 2012 and 2015. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of eight generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas with total net generating capacity of 4,482 MW. We sold our Indian River generating facility, which was included in the Other Operations segment, in January 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.

Operating Segments

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Three Months Ended March 31, 2012:							
Operating revenues(1)	$ 331	$ 305	$ 31	$ 6	$ 48	$	$ 721
Cost of fuel, electricity and other products(2)	115	154	1	(19)	27		278
Gross margin (excluding depreciation and amortization)	216	151	30	25	21		443
Operating Expenses:							
Operations and maintenance	106	130	45	2	25(3)		308
Depreciation and amortization	33	30	11		14		88
Gain on sales of assets, net		(1)			(7)		(8)
Total operating expenses	139	159	56	2	32		388
Operating income (loss)	$ 77	$ (8)	$ (26)	$ 23	$ (11)	$	$ 55
Total assets at March 31, 2012	$ 4,840	$ 3,405	$ 956	$ 2,544	$ 3,618(4)	$ (2,776)	$ 12,587

(1) Includes unrealized gains of $67 million, $65 million, $3 million, $4 million and $4 million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized losses of $25 million, $17 million and $1 million for Eastern PJM, Western PJM/MISO and Energy Marketing, respectively.

(3) Includes $2 million of Merger-related costs.

(4) Includes our equity method investment in Sabine Cogen, LP of $21 million.

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Operating Segments

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Three Months Ended March 31, 2011:							
Operating revenues(1)	$ 316	$ 324	$ 36	$ 85	$ 53	$	$ 814
Cost of fuel, electricity and other products(2)	138	163	2	66	32		401
Gross margin (excluding depreciation and amortization)	178	161	34	19	21		413
Operating Expenses:							
Operations and maintenance	106	111	39	4	45(3)		305
Depreciation and amortization	33	28	10		15		86
Gain on sales of assets, net					(1)		(1)
Total operating expenses	139	139	49	4	59		390
Operating income (loss)	$ 39	$ 22	$ (15)	$ 15	$ (38)	$	$ 23
Total assets at December 31, 2011	$ 4,732	$ 3,343	$ 856	$ 2,173	$ 3,662(4)	$ (2,497)	$ 12,269

(1) Includes unrealized losses of $51 million, $13 million, $24 million and $11 million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized gains of $12 million, $4 million, $2 million and $2 million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(3) Includes $23 million of Merger-related costs.

(4) Includes our equity method investment in Sabine Cogen, LP of $22 million.

	Three Months Ended March 31, 2012	2011
	(in millions)	
Operating income for all segments	$ 55	$ 23
Interest expense	(89)	(109)
Other, net	2	(22)
Loss before income taxes	$ (32)	$ (108)

10. Litigation and Other Contingencies

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 claims that it has not been paid in accordance with the terms of the EPC agreements for the scrubber projects and sought $143.1 million in liens against the properties. In March 2011, the court granted these liens. In June 2011, Stone & Webster filed a motion to amend its lien claims at these facilities by an additional $90.5 million. In August 2011, the court granted these additional liens. In September 2011, GenOn Mid-Atlantic paid $68 million to Stone & Webster for achieving substantial completion under the EPC agreements, which reduced the outstanding liens to $165.6 million. As a result of certain lien restrictions in its lease documentation,

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GenOn Mid-Atlantic has reserved $165.6 million of cash (which is included in funds on deposit in the consolidated balance sheets) in respect of such liens. The liens are interlocutory only and will not become final unless and until Stone & Webster is successful in prosecuting its contractual claims. We dispute 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 have been stayed pending resolution of the proceeding in New York. Assuming we are successful in pursuing our claims in the New York proceeding, the total estimated capital expenditures for compliance with the Maryland Healthy Air Act would not exceed $1.674 billion. However, if the costs were to equal the amount claimed by Stone &Webster in the litigation, the total capital expenditures would exceed $1.674 billion by approximately 5%. The New York proceeding has a trial date set for June 2012.

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.

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.

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.

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

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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 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 SO_2 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 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 assessing the need for 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 expect to resolve these issues by entering into an agreement with the PADEP that would obligate us to pay a civil penalty of $500,000. We would be responsible for 16.45% of this amount.

Keystone Wastewater Settlement with PADEP. In November 2011, the PADEP informed us that it believed that we had violated the Pennsylvania Clean Streams Law by (a) improperly permitting improvements to the plant required by the construction of scrubbers and (b) discharging stormwater associated with certain improvements. In March 2012, we settled this matter with the PADEP by agreeing to pay a civil penalty of $120,000. We are responsible for 16.67% 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 has 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

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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 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 of the Clean Water Act and Maryland s Water Pollution Control Law at Faulkner. 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 of the Clean Water Act and Maryland s Water Pollution Control Law at Brandywine. 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 intends to sue us for alleged violations of Maryland s water pollution laws at Westland. To date, MDE has not sued us regarding our ash disposal at Westland.

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 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 pursue 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 are discussing settlement. As a condition to obtaining the stay, we agreed in principle to pay a civil penalty of $1.9 million to the MDE if we reach a comprehensive settlement regarding all of the allegations related to the three Maryland ash facilities. Accordingly, we accrued $1.9 million during 2011. 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 continue to negotiate with the MDE. 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. There are no assurances that we will be able to settle the three matters. If we are able to settle the three matters, there are no assurances that we will be able to do so for the amounts that we have accrued. The ultimate resolution of these matters could be material to our results of operations, financial position and cash flows.

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 are continuing to remove the ash and do other clean up in coordination with the MDE and the property owners. At this time, we cannot reasonably estimate the upper range of our obligations for this matter principally because we have not finished (a) assessing the volume of fly ash to be removed and (b) determining how most effectively to access some of the affected areas. We are pursuing recovery under our insurance policies for our costs to remove and clean up the ash.

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 is considering seeking a fine in excess of $100,000 to settle the storm breach and the filling of wetlands without requisite permits. The MDE has not issued us a citation or NOV. We are currently in settlement discussions with the MDE.

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 ($39 million and $38 million at March 31, 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 March 31, 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 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.

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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 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

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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.

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 March 31, 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.

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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 23,700 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 57% in PJM, 23% in CAISO, 11% in NYISO and ISO NE, 8% in the Southeast and 1% in MISO. The net generating capacity of these facilities consists of approximately 39% baseload, 40% intermediate and 21% 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.

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 currently expect to deactivate the following generating capacity, primarily coal-fired units, at the referenced times: Niles unit 2 (108 MW) June 2012, Elrama units 1-3 (289 MW) mothball June 2012 and 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 will operate Niles unit 1 (109 MW) and Elrama unit 4 (171 MW) under RMR arrangements until October 1, 2012 whereupon we expect to deactivate those two units in the same manner as the other units at those facilities. The foregoing eight generating facilities contributed 13% to our realized gross margin during the year of 2011. While we continue to work with PJM to ensure that any reliability concerns that PJM may have regarding these deactivations are addressed, based on our discussions with PJM, we think that the units identified above for deactivation will be deactivated at the times referenced.

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 $611 million to $750 million over the next ten years 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.

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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 and do not require either party to post cash collateral for initial margin and, except as described in the next sentence, changes in power or natural gas prices. Beginning in April 2012, certain agreements entered into by GenOn Mid-Atlantic were amended to provide for the counterparty thereto to post collateral to secure credit exposure above the agreed threshold as a result of changes in power or natural gas prices. At April 9, 2012, our aggregate hedge levels based on expected generation for each year were as follows:

	2012(1)	2013	2014	2015	2016
Power	83%	55%	22%	13%	11%
Fuel	75%	42%	14%	9%	9%

(1) Percentages represent the period from May 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. The statute provides that standardized swap transactions between dealers and large market participants will have to be cleared and traded on an exchange or electronic platform. Although the provisions and legislative history of the Dodd-Frank Act provide strong evidence that market participants, such as us, which utilize OTC derivative financial instruments to hedge commercial risks are not to be subject to these clearing and exchange-trading requirements, it is uncertain what the final implementing regulations will provide. Under the Dodd-Frank Act, entities defined as swap dealers and major swap participants (SD/MSPs) will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. The Commodity Futures Trading Commission and the United States Securities and Exchange Commission voted in April 2012 to adopt a joint rule further defining the terms swap dealer and major swap participant among others. The final entity definition rule was released in late April 2012, and we are currently reviewing 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 an SD/MSP, the swap dealer definition in particular is ambiguous in certain respects and the designation as such will be decided by facts and circumstance tests.

Capital Expenditures and Capital Resources

During the three months ended March 31, 2012, we invested $82 million for capital expenditures, excluding capitalized interest paid. Capital expenditures for the period primarily relate to the construction of the Marsh Landing generating facility and maintenance capital expenditures. At March 31, 2012, we have invested $1.592 billion of the $1.674 billion that was budgeted for capital expenditures related to compliance with the Maryland Healthy Air Act. Provisions in the construction contracts for the scrubbers at our Maryland coal-fired units provide for certain payments to be made after final completion of the projects. See note 10 to our interim financial statements for further discussion involving the scrubber contract litigation.

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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:

	April 1, 2012 through December 31, 2012	2013
	(in millions)	
Maryland Healthy Air Act	$ 82	$
Other environmental	58	124
Maintenance	80	142
Marsh Landing generating facility	299	69
Other construction	10	
Other	11	10
Total	$ 540	$ 345

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.

Environmental Matters

Federal Rules Regarding CO_2. In April 2012, the EPA proposed a rule under the New Source Performance Standard section of the Clean Air Act that will limit the CO_2 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 CO_2 per MWh, which cannot be achieved by coal-fired units unless technology to capture and store CO_2 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 CO_2 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. 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 in January 2012 and a MPSC hearing, later 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

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Southwestern Mid-Atlantic Area Council zone of PJM to be constructed and operational by 2015. The contract will require that the generating facility be bid into the PJM capacity market in a manner consistent with the PJM tariff. On April 27, 2012, certain companies (not including us) filed in U.S. District Court for Maryland a complaint for declaratory and injunctive relief barring the implementation of the MPSC order. We expect 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.

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 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.

We experienced a decrease in power generation volumes during the three months ended March 31, 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 are at the maximum available storage capacity of such facilities. As it is impossible for us to take coal at such facilities, we have issued notices of force majeure under the respective coal contracts. A number of the suppliers dispute 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.

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) 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, and (i) 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 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 March 31, 2012 Compared to Three Months Ended March 31, 2011

Consolidated Financial Performance

We reported a net loss of $32 million and $111 million during the three months ended March 31, 2012 and 2011, respectively. The change in net loss is detailed as follows:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 343	$ 492	$ (149)
Unrealized gross margin	100	(79)	179
Total gross margin (excluding depreciation and amortization)	443	413	30
Operating expenses:			
Operations and maintenance	308	305	3
Depreciation and amortization	88	86	2
Gain on sales of assets, net	(8)	(1)	(7)
Total operating expenses	388	390	(2)
Operating income	55	23	32
Other income (expense), net:			
Interest expense, net	(89)	(109)	(20)
Other, net	2	(22)	(24)
Total other expense, net	(87)	(131)	(44)
Loss before income taxes	(32)	(108)	76
Provision for income taxes		3	(3)
Net Loss	$ (32)	$ (111)	$ 79

Realized Gross Margin. Our realized gross margin decrease of $149 million was principally a result of the following:

- a decrease of $176 million in energy, primarily as a result of (a) a $116 million decrease primarily resulting from reduced generation volumes as a result of contracting dark spreads, (b) $41 million related to lower of cost or market inventory adjustments, net and (c) a $39 million decrease in our Energy Marketing segment primarily as a result of decreases in fuel oil management, proprietary trading and transportation 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 was out-of-market and revalued as of the date of the 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

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- a decrease of $57 million 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

- an increase of $84 million in realized value of hedges, primarily as a result of a $102 million increase in power hedges primarily resulting from prices, offset in part by a $13 million decrease in coal hedges resulting from prices.

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

- unrealized gains of $100 million during the three months ended March 31, 2012, which included a $232 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. The increase was offset by $132 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized losses of $79 million during the three months ended March 31, 2011, which included $69 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $10 million net decrease in the value of hedge and proprietary trading contracts for future periods. The decrease in value was primarily related to increases in oil prices, offset by decreases in forward power and natural gas prices.

Operating Expenses. Our operating expenses decrease of $2 million was principally a result of the following:

- a $3 million increase in operations and maintenance expense primarily as a result of $35 million in costs to deactivate generating facilities (excess materials and supplies inventory reserve), partially offset by a $21 million decrease in Merger-related costs, primarily for severance and a $12 million decrease from lower employee headcount as a result of completion of Merger integration; partially offset by

- an increase of $7 million 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. Interest expense, net decrease of $20 million was principally a result of the following:

- an $18 million decrease related to lower interest expense as a result of repayment in 2011 of GenOn Americas Generation senior unsecured notes and PEDFA bonds.

Other, Net. Other, net change of $24 million was principally a result of the following:

- $24 million of other expense relating to the loss on extinguishment of debt primarily 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.

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Adjusted Net Income/Loss and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted net income/loss and adjusted EBITDA to net income/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 March 31, 2012 to the same period of 2011 and provides discussion of the changes.

	Three Months Ended March 31, 2012	2011
	(in millions)	
Net Loss	$ (32)	$ (111)
Unrealized (gains) losses	(100)	79
Merger-related costs	2	23
Lower of cost or market inventory adjustments, net	41	(8)
Loss on early extinguishment of debt		24
Major litigation costs, net of recoveries	2	
Advance settlement of out-of-market contract obligation	(20)	
Costs to deactivate generating facilities	35	
Other, net	(4)	
Adjusted Net Income (Loss)	(76)	7
Interest expense, net	89	109
Provision for income taxes		3
Depreciation and amortization	88	86
Adjusted EBITDA	$ 101	$ 205

Adjusted EBITDA was $101 million for the three months ended March 31, 2012 compared to $205 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 Merger cost savings.

The adjusted net loss was $76 million for the three months ended March 31, 2012 compared to adjusted net income of $7 million for the same period of 2011. The decline was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in interest expense, net.

Our net loss was $32 million for the three months ended March 31, 2012 compared to a net loss of $111 million for the same period of 2011. The decrease in net loss was primarily a result of an increase in unrealized gross margin, a loss on early extinguishment of debt in 2011 which was not repeated in 2012, a decrease in Merger-related costs and the advance settlement of an out-of-market contract obligation. These decreases were partially offset by the same items that affected adjusted net income/loss, an increase in lower of cost or market inventory adjustments, net and costs incurred in 2012 to deactivate generating facilities.

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.

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Gross Margin Overview

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

	Three Months Ended March 31, 2012					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
			(in millions)			
Energy	$ (15)	$ (5)	$ 1	$ 22	$ (2)	$ 1
Contracted and capacity	60	72	25		21	178
Realized value of hedges	129	36	1		(2)	164
Total realized gross margin	174	103	27	22	17	343
Unrealized gross margin	42	48	3	3	4	100
Total gross margin(1)	$ 216	$ 151	$ 30	$ 25	$ 21	$ 443

	Three Months Ended March 31, 2011					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
			(in millions)			
Energy	$ 61	$ 73	$	$ 41	$ 2	$ 177
Contracted and capacity	93	85	33		24	235
Realized value of hedges	63	12	1		4	80
Total realized gross margin	217	170	34	41	30	492
Unrealized gross margin	(39)	(9)		(22)	(9)	(79)
Total gross margin(1)	$ 178	$ 161	$ 34	$ 19	$ 21	$ 413

(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, through RMR arrangements (through February 28, 2011), through PPAs and tolling agreements, and from 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.

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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Operating Statistics

Our total margin capture factor was 93% and 90% during the three months ended March 31, 2012 and 2011, respectively. The following table summarizes power generation volumes by segment:

	Three Months Ended March 31, 2012	2011	Increase/ (Decrease)	Increase/ (Decrease) (2)
		(in gigawatt hours)		
Eastern PJM:				
Baseload	1,232	3,511	(2,279)	(65)%
Intermediate	220	18	202	NM
Peaking	10	18	(8)	(44)%
Total Eastern PJM	1,462	3,547	(2,085)	(59)%
Western PJM/MISO:				
Baseload	3,836	5,008	(1,172)	(23)%
Intermediate(1)		(2)	2	NM
Peaking(1)	(7)	(1)	(6)	NM
Total Western PJM/MISO	3,829	5,005	(1,176)	(23)%
California:				
Intermediate	18	33	(15)	(45)%
Total California	18	33	(15)	(45)%
Other Operations:				
Baseload	341	378	(37)	(10)%
Intermediate	5	18	(13)	(72)%
Peaking	31	11	20	NM
Total Other Operations	377	407	(30)	(7)%
Total	5,686	8,992	(3,306)	(37)%

(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 three months ended March 31, 2012, as compared to the same period in 2011, was primarily the result of the following:

Eastern PJM. A decrease in our baseload generation volumes primarily as a result of contracting dark spreads caused by milder temperature and lower demand.

Western PJM/MISO. A decrease in our baseload generation volumes primarily as a result of contracting dark spreads caused by milder temperature and lower demand, offset in part by an increase in generation by a combined cycle gas turbine generating facility primarily resulting from expanding spark spreads and a decrease in planned outages.

California. The decrease in our intermediate generation volumes was primarily the result of planned outages and lower real-time price volatility.

Other Operations. A decrease in our baseload and intermediate generation volumes was primarily as a result of contracting spark spreads caused by milder temperature and lower demand in the Northeast.

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Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,341 MW at March 31, 2012 and 2011.

The following table summarizes the results of operations of our Eastern PJM segment:

	Three Months Ended March 31, 2012	2011 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ (15)	$ 61	$ (76)
Contracted and capacity	60	93	(33)
Realized value of hedges	129	63	66
Total realized gross margin	174	217	(43)
Unrealized gross margin	42	(39)	81
Total gross margin (excluding depreciation and amortization)	216	178	38
Operating Expenses:			
Operations and maintenance	106	106	
Depreciation and amortization	33	33	
Total operating expenses, net	139	139	
Operating income	$ 77	$ 39	$ 38

Gross Margin

The decrease of $43 million in realized gross margin was principally a result of the following:

- a decrease of $76 million in energy, primarily as a result of a $55 million decrease in generation volumes as a result of contracting dark spreads and $21 million lower of cost or market inventory adjustments, net; and

- a decrease of $33 million in contracted and capacity primarily as a result of lower capacity prices; partially offset by

- an increase of $66 million in realized value of hedges, primarily as a result of a $76 million increase in power hedges primarily resulting from prices, offset in part by a $9 million decrease in coal hedges resulting from prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $42 million during the three months ended March 31, 2012, which included a $143 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 $101 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized losses of $39 million during the three months ended March 31, 2011, which included $54 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, partially offset by a $15 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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Western PJM/MISO

Our Western PJM/MISO segment includes 23 generating facilities with total net generating capacity of 7,483 MW at March 31, 2012 and 2011.

The following table summarizes the results of operations of our Western PJM/MISO segment:

	Three Months Ended March 31, 2012	2011 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ (5)	$ 73	$ (78)
Contracted and capacity	72	85	(13)
Realized value of hedges	36	12	24
Total realized gross margin	103	170	(67)
Unrealized gross margin	48	(9)	57
Total gross margin (excluding depreciation and amortization)	151	161	(10)
Operating Expenses:			
Operations and maintenance	130	111	19
Depreciation and amortization	30	28	2
Gain on sales of assets, net	(1)		(1)
Total operating expenses, net	159	139	20
Operating income (loss)	$ (8)	$ 22	$ (30)

Gross Margin

The decrease of $67 million in realized gross margin was principally a result of the following:

- a decrease of $78 million in energy, primarily as a result of a $58 million decrease in generation volumes as a result of contracting dark spreads and $20 million lower of cost or market inventory adjustments, net; and

- a decrease of $13 million in contracted and capacity primarily as a result of lower capacity prices; partially offset by

- an increase of $24 million in realized value of hedges, primarily as a result of a $28 million increase in power hedges primarily resulting from prices, offset in part by a $4 million decrease in coal hedges resulting from prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $48 million during the three months ended March 31, 2012, which included a $76 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 $28 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized losses of $9 million during the three months ended March 31, 2011, which included a $7 million net decrease in the value of hedge 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.

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Operating Expenses

The increase of $20 million in operating expenses was principally a result of the following:

- an increase of $19 million in operations and maintenance expense primarily as a result of $29 million in costs to deactivate generating facilities (excess materials and supplies inventory reserve), partially offset by $6 million primarily relating to decreased allocated corporate overhead costs as a result of completion of Merger integration.

California

Our California segment consists of seven generating facilities with total net generating capacity of 5,391 MW MW (excluding the Potrero facility of 362 MW, which was shut down on February 28, 2011) at March 31, 2012 and 2011. Our California segment also includes business development and construction activities for new generation in California, including GenOn Marsh Landing.

The following table summarizes the results of operations of our California segment:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ 1	$	$ 1
Contracted and capacity	25	33	(8)
Realized value of hedges	1	1	
Total realized gross margin	27	34	(7)
Unrealized gross margin	3		3
Total gross margin (excluding depreciation and amortization)	30	34	(4)
Operating Expenses:			
Operations and maintenance	45	39	6
Depreciation and amortization	11	10	1
Total operating expenses, net	56	49	7
Operating loss	$ (26)	$ (15)	$ (11)

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 28, 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.

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 $7 million in realized gross margin was primarily as a result of the shutdown of the Potrero generating facility in 2011.

Operating Expenses

The increase of $7 million in operating expenses was principally a result of the following:

• an increase of $6 million in operations and maintenance expense primarily as a result of a $3 million increase in projects and inspection outages and $2 million in costs to deactivate generating facilities (excess materials and supplies inventory reserve).

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Energy Marketing

Our Energy Marketing segment consists of proprietary trading, fuel oil management, and natural gas transportation and storage activities.

The following table summarizes the results of operations of our Energy Marketing segment:

	Three Months Ended March 31, 2012	2011 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ 22	$ 41	$ (19)
Total realized gross margin	22	41	(19)
Unrealized gross margin	3	(22)	25
Total gross margin (excluding depreciation and amortization)	25	19	6
Operating Expenses:			
Operations and maintenance	2	4	(2)
Total operating expenses, net	2	4	(2)
Operating income	$ 23	$ 15	$ 8

Gross Margin

The decrease of $19 million in realized gross margin was primarily as a result of a $39 million decrease in fuel oil management, proprietary trading and transportation 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 $3 million during the three months ended March 31, 2012, which included a $7 million net increase in the value of contracts for future periods primarily related to decreases in forward power prices, offset by $4 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized losses of $22 million during the three months ended March 31, 2011, which included a $16 million net decrease in the value of contracts for future periods and $6 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Other Operations

Our Other Operations segment consists of eight generating facilities with total net generating capacity of 4,482 MW at March 31, 2012 and nine generating facilities with total net generating capacity of 5,068 MW at March 31, 2011. We sold our Indian River generating facility (586 MW), which was included in the Other Operations segment, in January 2012 for $12 million. Other operations also includes unallocated overhead expenses and other activity that cannot be identified specifically with another segment.

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The following table summarizes the results of operations of our Other Operations segment:

	Three Months Ended March 31, 2012	2011 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ (2)	$ 2	$ (4)
Contracted and capacity	21	24	(3)
Realized value of hedges	(2)	4	(6)
Total realized gross margin	17	30	(13)
Unrealized gross margin	4	(9)	13
Total gross margin (excluding depreciation and amortization)	21	21	
Operating Expenses:			
Operations and maintenance	25	45	(20)
Depreciation and amortization	14	15	(1)
Gain on sales of assets, net	(7)	(1)	(6)
Total operating expenses, net	32	59	(27)
Operating loss	$ (11)	$ (38)	$ 27

Gross Margin

The decrease of $13 million in realized gross margin was principally a result of the following:

- a decrease of $6 million in realized value of hedges primarily as a result of a decline in the value realized from our gas, power and oil hedges;
- a decrease of $4 million in energy, primarily as a result of decreases in prices and generation volumes and capacity testing performed in 2012; and
- a decrease of $3 million in contracted and capacity primarily as a result of lower capacity prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $4 million during the three months ended March 31, 2012, which included a $2 million net increase in the value of hedge contracts for future periods and $2 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period; and

- unrealized losses of $9 million during the three months ended March 31, 2011, which included $6 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $3 million net decrease in the value of hedge contracts for future periods.

Operating Expenses

The decrease of $27 million in operating expenses was principally the result of the following:

- a decrease of $20 million in operations and maintenance expense primarily related to a decrease of $21 million in Merger-related costs, primarily for severance; and

- an increase of $6 million in gain on sales of assets as a result of the sale of our Indian River generating facility in January 2012.

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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.

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 cash, cash equivalents and availability under credit facilities of GenOn and its subsidiaries at March 31, 2012 (in millions):

Cash and Cash Equivalents:		
GenOn (excluding GenOn Mid-Atlantic and REMA)	$	1,579
GenOn Mid-Atlantic		119
REMA(1)		7
Total cash and cash equivalents		1,705
Less: cash reserved for other purposes		(12)
Total available cash and cash equivalents		1,693
Availability under GenOn credit facilities(2)		532
Total available cash, cash equivalents and availability under GenOn credit facilities(2)	$	2,225

(1) At March 31, 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) 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 March 31, 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.

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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 March 31, 2012, the present values of lease payments under the GenOn Mid-Atlantic and REMA operating leases were $903 million and $458 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 $1.3 billion and $729 million, respectively.

(3) At March 31, 2012, $47 million and $105 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 payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At March 31, 2012, GenOn Mid-Atlantic satisfied the restricted payments test. At March 31, 2012, REMA did not satisfy the restricted payments test.

As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $165.6 million of cash (which is included in funds on deposit in the consolidated balance sheets) in respect of such liens. See note 10 to our interim financial statements.

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 April 1, 2012 through December 31, 2013 will be $885 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.

At March 31, 2012, we had $230 million of posted cash collateral and $256 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 $114 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:

	March 31, 2012		December 31, 2011	
	(in millions)			
Cash collateral posted energy trading and marketing	$	171	$	185
Cash collateral posted other operating activities		59		39
Letters of credit Marsh Landing project(1)		158		175
Letters of credit rent reserves		137		130
Letters of credit energy trading and marketing		62		59
Letters of credit other operating activities		13		32
Surety bonds(2)		48		46
Total	$	648	$	666

(1) Includes $114 million and $131 million of cash-collateralized letters of credit at March 31, 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 March 31, 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 March 31, 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

Continuing Operations

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 decreased $151 million for the three months ended March 31, 2012, compared to the same period in 2011, primarily as a result of the following:

- *Realized gross margin.* A decrease in cash provided of $127 million in 2012 compared to 2011 (excluding lower of cost or market inventory adjustments of $46 million and out-of-market contract amortization of $1 million) primarily due to a $116 million reduction as a result of lower generation volumes, a $57 million decrease in contracted and capacity and a $39 million decrease in our Energy Marketing segment, partially offset by an increase of $84 million in realized value of hedges. See Results of Operations in Item 2 for additional discussion of our performance in 2012 as compared to the same period in 2011;

- *Inventories.* An increase in cash used of $101 million primarily related to changes in fuel oil and coal inventory;

- *Net receivables and accounts payable and accrued liabilities.* A decrease in cash provided of $51 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; and

- *Other operating assets and liabilities.* A decrease in cash provided of $50 million related to changes in other operating assets and liabilities.

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

- *Accounts payable, collateral.* An increase in cash provided of $90 million primarily as a result of $89 million posted by our counterparties in 2012 compared to $1 million returned to our counterparties in 2011;

- *Funds on deposit.* A decrease in cash used of $36 million primarily as a result of $6 million of additional collateral posted with our counterparties in 2012 compared to $42 million of additional collateral posted in 2011;

- *Operations and maintenance expense.* A decrease in cash used of $32 million primarily as a result of decreased Merger-related costs paid; and

- *Interest expense*. A decrease in cash used of $20 million primarily as a result of repayment in 2011 of GenOn Americas Generation senior unsecured notes and PEDFA bonds.

Investing Activities. Net cash provided by/used in investing activities changed by $996 million for the three months ended March 31, 2012, compared to the same period in 2011. This difference was primarily a result of the following:

- *Withdrawals from restricted funds on deposit*. A decrease in cash provided of $1.161 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. The withdrawal of cash was used to repay long-term debt during 2011; partially offset by

- *Payments into restricted funds on deposit*. A decrease in cash used of $143 million primarily related to funds placed in restricted deposits in 2011 as a result of our scrubber contract litigation and related liens;

- *Capital expenditures.* A decrease in cash used of $11 million primarily related to the construction of our Marsh Landing generating facility; and

- *Proceeds from the sales of assets.* An increase in cash provided of $11 million primarily related to the sale of the Indian River generating facility.

Financing Activities. Net cash provided by/used in financing activities changed by $1.196 billion for the three months ended March 31, 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 $1.151 billion primarily related to repayment during 2011of GenOn senior secured notes due 2014 and GenOn North America senior unsecured notes due 2013; and

- *Proceeds from long-term debt.* An increase in cash provided of $45 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.

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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

We are exposed to market risk, primarily associated with commodity prices. We also consider risks associated with interest rates and credit when valuing our derivative financial instruments.

The estimated net fair value of our derivative contract assets and liabilities was a net asset of $982 million and $637 million at March 31, 2012 and 2011, respectively. 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 three months ended March 31, 2012 and 2011:

	Commodity Contracts		Other Contracts	
	Asset Management	Trading	Interest Rate	Total
	(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)	234	(3)	2	233
Purchases(2)				
Issuances(2)				
Settlements(3)	(128)	(4)		(132)
Fair value of portfolio of assets and liabilities at March 31, 2012	$ 1,022	$ (10)	$ (30)	$ 982
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)	(2)	(15)	3	(14)
Purchases(2)				
Issuances(2)				
Settlements(3)	(61)	(8)		(69)
Fair value of portfolio of assets and liabilities at March 31, 2011	$ 643	$ (28)	$ 22	$ 637

(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.

We did not elect the fair value option for any financial instruments under the accounting guidance. However, we do transact using derivative financial instruments which are required to be recorded at fair value in our consolidated balance sheets under the accounting guidance related to derivative financial instruments.

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At March 31, 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	2016	2017 and thereafter	Total fair value
				(in millions)			
Asset Management:							
Prices actively quoted (Level 1)	$ (32)	$ 13	$ 14	$ 22	$ 41	$	$ 58
Prices provided by other external sources (Level 2)	350	368	276	50			1,044
Prices based on models and other valuation methods (Level 3)	(58)	(21)	(2)	1			(80)
Total asset management	$ 260	$ 360	$ 288	$ 73	$ 41	$	$ 1,022
Trading Activities:							
Prices actively quoted (Level 1)	$ (20)	$	$	$	$	$	$ (20)
Prices provided by other external sources (Level 2)	(28)	(6)					(34)
Prices based on models and other valuation methods (Level 3)	37	7					44
Total trading activities	$ (11)	$ 1	$	$	$	$	$ (10)
Interest Rate:							
Prices actively quoted (Level 1)	$	$	$	$	$	$	$
Prices provided by other external sources (Level 2)	(1)	(8)	(10)	(7)	(4)		(30)
Prices based on models and other valuation methods (Level 3)							
Total interest rate	$ (1)	$ (8)	$ (10)	$ (7)	$ (4)	$	$ (30)

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.

Counterparty Credit Risk

The valuation of our derivative contract assets is affected by the default risk of the counterparties with which we transact. We recognized a credit valuation adjustment, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $24 million and $48 million at March 31, 2012 and December 31, 2011, respectively.

In accordance with the fair value measurements accounting guidance, we calculate the credit valuation adjustment through consideration of observable market inputs, when available. We calculate our credit valuation adjustment using published spreads, where available, or proxies based upon published spreads, on credit default swaps for our counterparties applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. We do not, however, transact in credit default swaps or any other

credit derivative. Potential loss exposure is calculated as our current exposure plus a calculated VaR over the remaining life of the contracts.

Our non-collateralized power hedges entered into by GenOn Mid-Atlantic with financial institutions, which represent 35% of our net notional power position at March 31, 2012, are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties and do not require either party to post cash collateral for initial margin and, except as described in the next sentence, changes in power or natural gas prices. Beginning in April 2012, certain agreements entered into by GenOn Mid-Atlantic were amended to provide for the counterparty thereto to post collateral to secure credit exposure above the agreed threshold as a result of changes in power or natural gas prices. Our coal contracts included in derivative contract assets and liabilities in the consolidated balance sheets also do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in coal prices. 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 March 31, 2012.

Once we have delivered a physical commodity or agreed to financial settlement terms, we are subject to collection risk. Collection risk is similar to credit risk and collection risk is accounted for when we establish our provision for uncollectible accounts. We manage this risk using the same techniques and processes used in credit risk discussed above.

We also monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. See note 3 to our interim financial statements.

Interest Rate Risk

Fair Value Measurement

We are also subject to interest rate risk when discounting to account for time value in determining the fair value of our derivative contract assets and liabilities. The nominal value of our derivative contract assets and liabilities is discounted using a LIBOR forward interest rate curve based on the tenor of our transactions. We estimate that a one percentage point change in market interest rates would result in a change of $18 million to our derivative contract assets and a change of $7 million to our derivative contract liabilities at March 31, 2012.

Debt

Some of our debt is subject to variable interest rates, including our $690 million senior secured term loan and our $788 million senior secured revolving credit facility. With the senior secured term loan fully drawn, it is estimated that a one percentage point change in market interest rates above 1.75% would result in a change in our annual interest expense of $7 million. If the senior secured revolving credit facility were fully drawn, we estimate that a one percentage point change in market interest rates would result in a change in our annual interest expense of $8 million.

The GenOn Marsh Landing credit agreement is also subject to variable interest rates. The credit facility consists of a $155 million tranche A senior secured term loan facility, a $345 million tranche B senior secured term loan facility, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing s debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing s collateral requirements under its PPA with PG&E. The interest rate swaps cover 100% of the expected outstanding term loan balances during the operating period and a substantial portion of the expected outstanding term loan balances during the construction period. The remaining borrowings during the construction period are still subject to variability in interest rates. At the projected peak borrowing levels during the construction period, a one percentage point change in market interest rates would result in a change in our annual interest cost of less than $1 million.

Coal Agreement Risk

Our coal supply comes primarily from the Northern Appalachian and Central Appalachian coal regions. We enter into contracts of varying tenors to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number

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of suppliers under contracts with terms of varying lengths, some of which extend to 2014 and one that extends to 2020. Excluding our Keystone and Conemaugh generating facilities (which are not 100% owned by us) and excluding our Seward generating facility (which burns waste coal supplied under an all-requirements contract), we had exposure to three counterparties at March 31, 2012 and December 31, 2011, respectively, that each represented more than 10% of our total coal commitments, by volume, for the respective succeeding year, and in aggregate represented 63% and 62% of our total coal commitments, by volume, at March 31, 2012 and December 31, 2011, respectively. At March 31, 2012 and December 31, 2011, the single largest counterparty represented an exposure of 38%, respectively, of these total coal commitments, by volume.

In addition, we have non-performance risk associated with our coal agreements. There is risk that our coal suppliers may not provide the contractual quantities on the dates specified within the agreements, or the deliveries may be carried over to future periods. If our coal suppliers do not perform in accordance with the agreements, we may have to procure coal in the market to meet our needs, or power in the market to meet our obligations. In addition, generally our coal suppliers do not have investment grade credit ratings nor do they post collateral with us and, accordingly, we may have limited ability to collect damages in the event of default by such suppliers. We seek to mitigate this risk through diversification of coal suppliers, to the extent possible, and through guarantees. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers. Non-performance or default risk by our coal suppliers could have a material adverse effect on our future results of operations, financial condition and cash flows.

Certain of our coal contracts are not required to be recorded at fair value under the accounting guidance for derivative financial instruments. As such, these contracts are not included in derivative contract assets and liabilities in the consolidated balance sheets. These contracts contain pricing terms that are unfavorable compared to forward market prices at March 31, 2012, and are projected to result in a $40 million expense to our realized value of hedges through 2014 as the coal is utilized in the production of electricity.

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 March 31, 2012. Based upon this assessment, our management concluded that, as of March 31, 2012, the design and operation of these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting that have occurred during the quarter ended March 31, 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

In our 2011 Annual Report on Form 10-K we included a risk factor titled *Our income tax NOL carry forwards could be substantially limited if we experience an ownership change as defined in the IRC.* In this risk factor we disclosed that it was possible that RRI Energy had experienced an ownership change under the applicable tax rules as a result of the Merger. Based on further inquiries, we do not think that RRI Energy experienced an ownership change as a result of the Merger or following the Merger through December 31, 2011.

ITEM 5. OTHER INFORMATION

On May 9, 2012, our Board of Directors determined that one of the funds affiliated with Orbis Investment Management Limited acquired shares of our common stock that constituted prohibited transfers under the Protective Charter Amendment. The Protective Charter Amendment was approved by our stockholders at our 2011 annual meeting in order to help protect our net operating loss carry forwards. Prohibited transfers are void *ab initio* (from the start) under the Protective Charter Amendment, unless the transfers are approved by the Board of Directors. The Board of Directors did not approve any prohibited transfers. The excess shares acquired by the Orbis Investment Management Limited fund have been sold in a manner that complied with the Protective Charter Amendment.

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ITEM 6. EXHIBITS

Exhibit No.	Exhibit Name
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)
4.1*	Form of Stock Certificate
10.1*	2012 Restricted Stock Unit Award Agreement for Edward R. Muller under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, dated February 27, 2012
10.2*	2012 Performance Unit Award Agreement for Edward R. Muller under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, dated February 27, 2012
10.3*	2012 Nonqualified Stock Option Award Agreement for Edward R. Muller under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, dated February 27, 2012
10.4*	Form of 2012 Restricted Stock Unit Award Agreement for Officers under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan
10.5*	Form of 2012 Performance Unit Award Agreement for Officers under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan
10.6*	Form of 2012 Nonqualified Stock Option Award Agreement for Officers under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan

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Exhibit No.	Exhibit Name
10.7*	GenOn Energy, Inc. Change in Control Severance Plan effective as of February 27, 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.

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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: May 10, 2012	By:	/s/ THOMAS C. LIVENGOOD Thomas C. Livengood *Senior Vice President and Controller* *(Duly Authorized Officer and Principal Accounting Officer)*