NRG ENERGY, INC.
Form 10-Q
November 02, 2012

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: September 30, 2012
o	Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission File Number: 001-15891
NRG Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-1724239 (I.R.S. Employer Identification No.)
211 Carnegie Center, Princeton, New Jersey (Address of principal executive offices)	08540 (Zip Code)

(609) 524-4500
(Registrant's telephone number, including area code)

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

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

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).
Yes o No x

As of October 31, 2012, there were 228,297,805 shares of common stock outstanding, par value $0.01 per share.

TABLE OF CONTENTS

Index

CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

This Quarterly Report on Form 10-Q of NRG Energy, Inc., or NRG or the Company, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or Exchange Act. The words "believes," "projects," "anticipates," "plans," "expects," "intends," "estimates" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause NRG's actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Item 1A — Risk Factors Related to NRG Energy, Inc., in Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and Item 1A — Risk Factors, in Part II, Item 1A of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, including, but not limited to, the following:

- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- Volatile power supply costs and demand for power;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that NRG may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of NRG's risk management policies and procedures, and the ability of NRG's counterparties to satisfy their financial commitments;
- Counterparties' collateral demands and other factors affecting NRG's liquidity position and financial condition;
- NRG's ability to operate its businesses efficiently, manage capital expenditures and costs tightly, and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;
- NRG's ability to enter into contracts to sell power and procure fuel on acceptable terms and prices;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Government regulation, including compliance with regulatory requirements and changes in market rules, rates, tariffs and environmental laws and increased regulation of carbon dioxide and other greenhouse gas emissions;
- Price mitigation strategies and other market structures employed by ISOs or RTOs that result in a failure to adequately compensate NRG's generation units for all of its costs;
- NRG's ability to borrow additional funds and access capital markets, as well as NRG's substantial indebtedness and the possibility that NRG may incur additional indebtedness going forward;
- NRG's ability to receive Federal loan guarantees or cash grants to support development projects;
- Operating and financial restrictions placed on NRG and its subsidiaries that are contained in the indentures governing NRG's outstanding notes, in NRG's 2011Senior Credit Facility, and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;
- NRG's ability to implement its strategy of developing and building new power generation facilities, including new solar projects;
- NRG's ability to implement its econrg strategy of finding ways to address environmental challenges while taking advantage of business opportunities;
- NRG's ability to implement its FORNRG strategy to increase cash from operations through operational and commercial initiatives, corporate efficiencies, asset strategy, and a range of other programs throughout the company to reduce costs or generate revenues;
- NRG's ability to achieve its strategy of regularly returning capital to stockholders;
- NRG's ability to maintain retail market share;
- NRG's ability to successfully evaluate investments in new business and growth initiatives;
- NRG's ability to successfully integrate and manage any acquired businesses;

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

Forward-looking statements speak only as of the date they were made, and NRG Energy, Inc. undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors that could cause NRG's actual results to differ materially from those contemplated in any forward-looking statements included in this Quarterly Report on Form 10-Q should not be construed as exhaustive.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

2011 Form 10-K	NRG’s Annual Report on Form 10-K for the year ended December 31, 2011
2011 Revolving Credit Facility	The Company's $2.3 billion revolving credit facility due 2016, a component of the 2011 Senior Credit Facility
2011 Senior Credit Facility	As of July 1, 2011, NRG's senior secured facility, comprised of a $1.6 billion term loan facility and a $2.3 billion revolving credit facility
316(b) Rule	A section of the Clean Water Act regulating cooling water intake structures
Baseload capacity	Coal and nuclear electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
Capital Allocation Plan	Share repurchase and shareholder dividend program
Capital Allocation Program	NRG's plan of allocating capital between debt reduction, reinvestment in the business, share repurchases and shareholder dividends through the Capital Allocation Plan
CDWR	California Department of Water Resources
C&I	Commercial, industrial and governmental/institutional
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
Distributed Solar	Solar power projects, typically less than 20 MW in size (on an alternating current, or AC, basis), that primarily sell power produced to customers for usage on site, or are interconnected to sell power into the local distribution grid
DNREC	Delaware Department of Natural Resources and Environmental Control
Energy Plus	Energy Plus Holdings LLC
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas

Exchange Act	The Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
GenOn	GenOn Energy, Inc.
GHG	Greenhouse Gases
Green Mountain Energy	Green Mountain Energy Company
GWh	Gigawatt hour

Heat Rate	A measure of thermal efficiency computed by dividing the total BTU content of the fuel burned by the resulting kWhs generated. Heat rates can be expressed as either gross or net heat rates, depending whether the electricity output measured is gross or net generation and is generally expressed as BTU per net kWh
ISO	Independent System Operator, also referred to as Regional Transmission Organizations, or RTO
ITC	Investment Tax Credit
LIBOR	London Inter-Bank Offered Rate
LTIP	Long-Term Incentive Plan
Mass	Residential and small business
Merger Agreement	Agreement and Plan of Merger by and among NRG Energy, Inc., Plus Merger Corporation and GenOn Energy, Inc. dated as of July 20, 2012
Merit Order	A term used for the ranking of power stations in order of ascending marginal cost
MMBtu	Million British Thermal Units
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NAAQS	National Ambient Air Quality Standards
NINA	Nuclear Innovation North America LLC
NO_x	Nitrogen oxide
NPNS	Normal Purchase Normal Sale
NRC	U.S. Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
OCI	Other comprehensive income
PJM	PJM Interconnection, LLC
PJM market	The wholesale and retail electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia

PM 2.5	Particulate matter particles with a diameter of 2.5 micrometers or less
PPA	Power Purchase Agreement
PUCT	Public Utility Commission of Texas
Repowering	Technologies utilized to replace, rebuild, or redevelop major portions of an existing electrical generating facility, not only to achieve a substantial emissions reduction, but also to increase facility capacity, and improve system efficiency
SEC	United States Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended

Senior Notes	The Company's \$6.2 billion outstanding unsecured senior notes, consisting of \$270 million of 7.375% senior notes due 2017, \$1.2 billion of 7.625% senior notes due 2018, \$700 million of 8.5% senior notes due 2019, \$800 million of 7.625% senior notes due 2019, \$1.1 billion of 8.25% senior notes due 2020, \$1.1 billion of 7.875% senior notes due 2021, and \$990 million of 6.625% senior notes due 2023
SO_2	Sulfur dioxide
STP	South Texas Project — nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest
Term Loan Facility	Prior to July 1, 2011, a senior first priority secured term loan, of which approximately \$608 million would have matured on February 1, 2013, and \$990 million would have matured on August 31, 2015, and was a component of NRG's Senior Credit Facility. On July 1, 2011, NRG replaced its Senior Credit Facility, including the Term Loan Facility, with the 2011 Senior Credit Facility.
U.S.	United States of America
U.S. DOE	U.S. Department of Energy
U.S. DOJ	U.S. Department of Justice
U.S. EPA	U.S. Environmental Protection Agency
U.S. GAAP	Accounting principles generally accepted in the United States
Utility Scale Solar	Solar power projects, typically 20 MW or greater in size (on an alternating current, or AC, basis), that are interconnected into the transmission or distribution grid to sell power at a wholesale level
VaR	Value at Risk
VIE	Variable Interest Entity

PART I — FINANCIAL INFORMATION
ITEM 1 — CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
(In millions, except for per share amounts)	2012	2011	2012	2011
Operating Revenues				
Total operating revenues	$2,331	$2,674	$6,359	$6,947
Operating Costs and Expenses				
Cost of operations	1,726	2,053	4,618	4,985
Depreciation and amortization	239	238	703	665
Impairment charge on emission allowances	—	160	—	160
Selling, general and administrative	253	169	681	479
Acquisition-related transaction and integration costs	18	—	18	—
Development costs	9	11	26	32
Total operating costs and expenses	2,245	2,631	6,046	6,321
Operating Income	86	43	313	626
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	4	16	26	26
Impairment charge on investment	(1)	(3)	(2)	(495)
Other income, net	10	5	14	13
Loss on debt extinguishment	(41)	(32)	(41)	(175)
Interest expense	(163)	(164)	(495)	(504)
Total other expense	(191)	(178)	(498)	(1,135)
Loss Before Income Taxes	(105)	(135)	(185)	(509)
Income tax benefit	(113)	(80)	(246)	(815)
Net Income/(Loss)	8	(55)	61	306
Less: Net income attributable to noncontrolling interest	9	—	18	—
Net (Loss)/Income Attributable to NRG Energy, Inc.	(1)	(55)	43	306
Dividends for preferred shares	2	2	7	7
(Loss)/Income Available for Common Stockholders	$(3)	$(57)	$36	$299
(Loss)/Earnings Per Share Attributable to NRG Energy, Inc. Common Stockholders				
Weighted average number of common shares outstanding — basic	228	240	228	243
Net (loss)/income per weighted average common share — basic	$(0.01)	$(0.24)	$0.16	$1.23
Weighted average number of common shares outstanding — diluted	228	240	230	245
Net (loss)/income per weighted average common share — diluted	$(0.01)	$(0.24)	$0.16	$1.22
Dividends Per Common Share	$0.09	$—	$0.09	$—

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS)/INCOME
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Net Income/(Loss)	$8	$(55)	$61	$306
Other comprehensive (loss)/income, net of tax				
Unrealized loss on derivatives, net of income tax benefit of $24, $45, $76, and $131	(43)	(76)	(132)	(225)
Foreign currency translation adjustments, net of income tax benefit of $0, $16, $1 and $4	1	(27)	(1)	(5)
Reclassification adjustment for translation gain realized upon sale of Schkopau, net of income tax expense of $6, $0, $6, and $0	(11)	—	(11)	—
Available-for-sale securities, net of income tax benefit/(expense) of $(1), $1, $(1), and $1	2	(1)	2	(2)
Defined benefit plans	—	—	—	1
Other comprehensive loss	(51)	(104)	(142)	(231)
Comprehensive (loss)/income	(43)	(159)	(81)	75
Less: Comprehensive income attributable to noncontrolling interest	9	—	18	—
Comprehensive (loss)/income attributable to NRG Energy, Inc.	(52)	(159)	(99)	75
Dividends for preferred shares	2	2	7	7
Comprehensive (loss)/income available for common stockholders	$(54)	$(161)	$(106)	$68

See accompanying notes to condensed consolidated financial statements.

8

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except shares)	September 30, 2012 (unaudited)	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$1,610	$1,105
Funds deposited by counterparties	76	258
Restricted cash	237	292
Accounts receivable — trade, less allowance for doubtful accounts of $39 and $23	1,075	834
Inventory	393	308
Derivative instruments	2,677	4,216
Cash collateral paid in support of energy risk management activities	98	311
Prepayments and other current assets	217	273
Total current assets	6,383	7,597
Property, plant and equipment, net of accumulated depreciation of $5,194 and $4,570	15,866	13,621
Other Assets		
Equity investments in affiliates	649	640
Note receivable — affiliate and capital leases, less current portion	78	342
Goodwill	1,886	1,886
Intangible assets, net of accumulated amortization of $1,628 and $1,452	1,188	1,419
Nuclear decommissioning trust fund	469	424
Derivative instruments	309	450
Other non-current assets	392	336
Total other assets	4,971	5,497
Total Assets	$27,220	$26,715
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$374	$87
Accounts payable	1,246	808
Derivative instruments	2,462	3,751
Deferred income taxes	15	127
Cash collateral received in support of energy risk management activities	76	258
Accrued expenses and other current liabilities	604	640
Total current liabilities	4,777	5,671
Other Liabilities		
Long-term debt and capital leases	10,968	9,745
Nuclear decommissioning reserve	349	335
Nuclear decommissioning trust liability	277	254
Deferred income taxes	1,092	1,389
Derivative instruments	561	464
Out-of-market commodity contracts	161	183
Other non-current liabilities	896	756
Total non-current liabilities	14,304	13,126
Total Liabilities	19,081	18,797
	249	249

3.625% convertible perpetual preferred stock (at liquidation value, net of issuance costs)		
Commitments and Contingencies		
Stockholders’ Equity		
Common stock	3	3
Additional paid-in capital	5,388	5,346
Retained earnings	4,002	3,987
Less treasury stock, at cost — 76,505,718 and 76,664,199 shares, respectively	(1,920)	(1,924)
Accumulated other comprehensive (loss)/income	(68)	74
Noncontrolling interest	485	183
Total Stockholders’ Equity	7,890	7,669
Total Liabilities and Stockholders’ Equity	$27,220	$26,715

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine months ended September 30,	
	2012	2011
	(In millions)	
Cash Flows from Operating Activities		
Net income	$61	$306
Adjustments to reconcile net income to net cash provided by operating activities:		
Distributions and equity in earnings of unconsolidated affiliates	8	8
Depreciation and amortization	703	665
Provision for bad debts	40	41
Amortization of nuclear fuel	29	31
Amortization of financing costs and debt discount/premiums	25	25
Loss on debt extinguishment	8	58
Amortization of intangibles and out-of-market commodity contracts	108	118
Amortization of unearned equity compensation	27	14
Changes in deferred income taxes and liability for uncertain tax benefits	(261)	(829)
Changes in nuclear decommissioning trust liability	25	20
Changes in derivative instruments	360	(201)
Changes in collateral deposits supporting energy risk management activities	213	7
Impairment charge on investment	—	481
Impairment charge on emission allowances	—	160
Cash used by changes in other working capital	(288)	(236)
Net Cash Provided by Operating Activities	1,058	668
Cash Flows from Investing Activities		
Acquisitions of businesses, net of cash acquired	(40)	(352)
Capital expenditures	(2,474)	(1,355)
Increase in restricted cash, net	(96)	(92)
Decrease/(increase) in restricted cash to support equity requirements for U.S. DOE funded projects	151	(316)
(Increase)/decrease in notes receivable	(22)	27
Purchases of emission allowances	(8)	(27)
Proceeds from sale of emission allowances	8	6
Investments in nuclear decommissioning trust fund securities	(341)	(314)
Proceeds from sales of nuclear decommissioning trust fund securities	316	294
Proceeds from renewable energy grants	49	—
Proceeds from sale of assets, net of cash disposed of	137	14
Investments in unconsolidated affiliates	—	(17)
Other	(9)	(29)
Net Cash Used by Investing Activities	(2,329)	(2,161)
Cash Flows from Financing Activities		
Payment of dividends to common and preferred stockholders	(28)	(7)
Payment for treasury stock	—	(378)
Net payments for settlement of acquired derivatives that include financing elements	(65)	(61)
Sale proceeds and other contributions from noncontrolling interests in subsidiaries	316	—
Proceeds from issuance of long-term debt	2,541	5,710
Decrease in restricted cash supporting funded letter of credit	—	1,300

Payment for settlement of funded letter of credit facility	—	(1,300)
Proceeds from issuance of common stock	—	2
Payment of debt issuance and hedging costs	(30)	(149)
Payments for short and long-term debt	(955)	(5,450)
Net Cash Provided/(Used) by Financing Activities	1,779	(333)
Effect of exchange rate changes on cash and cash equivalents	(3)	2
Net Increase/(Decrease) in Cash and Cash Equivalents	505	(1,824)
Cash and Cash Equivalents at Beginning of Period	1,105	2,951
Cash and Cash Equivalents at End of Period	$1,610	$1,127

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 — Basis of Presentation

NRG Energy, Inc., or NRG or the Company, is an integrated wholesale power generation and retail electricity company that aspires to be a leader in the way the industry and consumers think about, use, produce and deliver energy and energy services in major competitive power markets in the United States. First, NRG is a wholesale power generator engaged in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services. Second, NRG is a retail electricity company engaged in the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through its Retail businesses, which include Reliant Energy, Green Mountain Energy and Energy Plus. Finally, NRG is focused on the deployment and commercialization of potential disruptive clean energy technologies, like electric vehicles, Distributed Solar and smart meter technology, which have the potential to change the nature of the power supply industry.

The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission's, or SEC's, regulations for interim financial information and with the instructions to Form 10-Q. Accordingly, they do not include all of the information and notes required by generally accepted accounting principles for complete financial statements. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to the Company's financial statements in its Annual Report on Form 10-K for the year ended December 31, 2011, or 2011 Form 10-K. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim condensed consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly the Company's consolidated financial position as of September 30, 2012, and the results of operations, comprehensive (loss)/income and cash flows for the three and nine months ended September 30, 2012, and 2011.

Use of Estimates

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions. These estimates and assumptions impact the reported amount of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the consolidated financial statements. They also impact the reported amount of net earnings during the reporting period. Actual results could be different from these estimates.

Note 2 — Summary of Significant Accounting Policies

Other Cash Flow Information

NRG’s investing activities exclude capital expenditures of $712 million which were accrued and unpaid at September 30, 2012, primarily for solar projects under construction.

Noncontrolling Interests

The following table reflects the changes in NRG's noncontrolling interest balance:

	(In millions)
Balance as of December 31, 2011	$183
Sale proceeds and cash contributions	284
Comprehensive income attributable to noncontrolling interest	18
Balance as of September 30, 2012	$485

Tax Credits

NRG accounts for income taxes in accordance with Accounting Standards Codification, or ASC, 740, Income Taxes, or ASC 740, which requires that the Company use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences, as further described in Note 2, Summary of Significant Accounting Policies, to the Company's 2011 Form 10-K. NRG reduces its current income tax expense in the consolidated statement of operations for any investment tax credits, or ITCs, that are not convertible into cash grants, as well as other tax credits, in the period the tax credit is generated. ITCs that are convertible into cash grants, as well as the deferred income tax benefit generated by the difference in the financial statement and tax basis of the related assets, are recorded as a reduction to the carrying value of the underlying property and subsequently amortized to earnings on a straight-line basis over the useful life of each underlying property.

Recent Accounting Developments

Effective January 1, 2012, the Company adopted the provisions of Accounting Standards Update, or ASU, No. 2011-05, Comprehensive Income (Topic 220) Presentation of Comprehensive Income, or ASU No. 2011-05, and began presenting the total of comprehensive income, the components of net income and the components of other comprehensive income in two separate but consecutive statements. The provisions of ASU No. 2011-05 are required to be adopted retroactively. As this guidance provides only presentation requirements, the adoption of this standard did not impact the Company's results of operations, cash flows or financial position.

Note 3 — Business Acquisitions and Dispositions

Pending Acquisition

On July 20, 2012, the Company entered into an agreement, or the Merger Agreement, to acquire GenOn Energy, Inc., or GenOn. GenOn, a generator of wholesale electricity, has baseload, intermediate and peaking power generation facilities using coal, natural gas and oil, totaling approximately 22,700 MW. The Company will issue, as consideration for the acquisition, 0.1216 shares of NRG common stock for each outstanding share of GenOn, including restricted stock units outstanding, on the acquisition date, except for fractional shares which will be paid in cash. Based upon total GenOn shares outstanding as of September 30, 2012, the Company expects to issue approximately 94 million shares of NRG common stock, or 29% of total common shares outstanding following the close of the transaction.

NRG and GenOn will hold their respective special meetings of stockholders on November 9, 2012. The stockholders who held shares of NRG and GenOn on Friday, October 5, 2012, will be entitled to vote at their respective special meeting on the proposals pertaining to the merger of the companies.

On September 21, 2012, the Department of Justice and the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. On October 25, 2012, the Public Utility Commission of Texas, or PUCT, approved the merger. Additionally, the 90-day prior notice period to the California Public Utilities Commission, or CPUC, required under California law expired on October 31, 2012.

The merger remains subject to the satisfaction or waiver of other closing conditions, including approval by the stockholders of both companies and regulatory approvals by the Federal Energy Regulatory Commission, or the FERC, and the New York Public Service Commission, or NYPSC. Additionally, the companies have requested a threshold determination by the U.S. Nuclear Regulatory Commission, or the NRC, that its approval is not required. The acquisition is expected to close by the first quarter of 2013.

2012 Dispositions

Agua Caliente

On January 18, 2012, the Company completed the sale of a 49% interest in NRG Solar AC Holdings LLC, the indirect owner of the Agua Caliente project, to MidAmerican Energy Holdings Company, or MidAmerican. A majority of the $122 million of cash consideration received at closing represented 49% of construction costs funded by NRG's equity contributions. The excess of the consideration over the carrying value of the divested interest was recorded to additional paid-in capital. MidAmerican will fund its proportionate share of future equity contributions and other credit support for the project. NRG continues to hold a majority interest in and consolidate the project.

Saale Energie GmbH

On July 17, 2012, the Company completed the sale of its 100% interest in Saale Energie GmbH, which holds a 41.9% interest in Kraftwerke Schkopau GbR and a 44.4% interest in Kraftwerke Schkopau Betriebsgesllschaft mbH, collectively, Schkopau. Schkopau holds a fixed 400 MW participation in the 900 MW Schkopau Power Station located in Germany. In connection with the sale of Schkopau, NRG entered into a foreign currency swap contract to hedge the impact of exchange rate fluctuations on the sale proceeds of €141 million. The Company received cash consideration, net of selling expenses, of $174 million, which included $4 million related to the settlement of the swap contract that was recorded as a gain within Other income, net in the quarter ended September 30, 2012. The cash consideration approximated the book value of the net assets, including cash of $38 million, on the date of the sale.

2011 Acquisitions

The Company's acquisitions that are considered business combinations are accounted for under the acquisition method of accounting in accordance with ASC 805, Business Combinations, or ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The provisional amounts recognized are subject to revision until the evaluations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date, are required to be finalized within a measurement period not to exceed one year. The Company made several acquisitions in 2011, which were recorded as business combinations under ASC 805, for which the accounting was not finalized as of December 31, 2011. See Note 3, Business Acquisitions and Dispositions and Note 12, Debt and Capital Leases, in the Company's 2011 Form 10-K, for additional information related to these acquisitions.

The accounting for the acquisitions of Energy Plus, California Valley Solar Ranch, or CVSR, Agua Caliente and Ivanpah were completed as of March 31, 2012, at which point the provisional fair values became final with no material changes.

Note 4 — Nuclear Innovation North America LLC, or NINA, Impairment Charge

As discussed in detail in Note 4, Nuclear Innovation North America LLC Developments, Including Impairment Charge, to the Company's 2011 Form 10-K, NRG deconsolidated NINA as of March 31, 2011, and recorded an impairment charge of $495 million for the nine months ended September 30, 2011, including $481 million in the quarter ended March 31, 2011 for the full amount of its investment, $11 million in the quarter ended June 30, 2011 and $3 million for the quarter ended September 30, 2011.

Note 5 — Fair Value of Financial Instruments

This footnote should be read in conjunction with the complete description under Note 5, Fair Value of Financial Instruments, to the Company's 2011 Form 10-K.

For cash and cash equivalents, funds deposited by counterparties, restricted cash, and cash collateral paid and received in support of energy risk management activities, the carrying amount approximates fair value because of the short-term maturity of those instruments. Debt securities, equity securities, trust fund investments, which are comprised of various U.S. debt and equity securities, and derivative assets and liabilities are carried at fair market value.

The estimated carrying values and fair values of NRG's recorded financial instruments not carried at fair market value are as follows:

	As of September 30, 2012		As of December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets:				
Notes receivable	$84	$84	$156	$161
Liabilities:				
Long-term debt, including current portion	11,342	11,817	9,729	9,716

The fair value of the Company's publicly-traded long-term debt is based on quoted market prices and is classified as Level 1 within the fair value hierarchy. The fair value of debt securities, non publicly-traded long-term debt, and certain notes receivable of the Company are based on expected future cash flows discounted at market interest rates, or current interest rates for similar instruments with equivalent credit quality and are classified as Level 3 within the fair value hierarchy.

Recurring Fair Value Measurements

For cash and cash equivalents, funds deposited by counterparties, restricted cash, and cash collateral paid and received in support of energy risk management activities, the carrying amount approximates fair value because of the nature and short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

The following tables present assets and liabilities measured and recorded at fair value on the Company's condensed consolidated balance sheet on a recurring basis and their level within the fair value hierarchy:

	As of September 30, 2012			
	Fair Value			
(In millions)	Level 1	Level 2	Level 3	Total
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$—	$—	$11	$11
Marketable equity securities	1	—	—	1
Trust fund investments:				
Cash and cash equivalents	4	—	—	4
U.S. government and federal agency obligations	34	—	—	34
Federal agency mortgage-backed securities	—	63	—	63
Commercial mortgage-backed securities	—	6	—	6
Corporate debt securities	—	72	—	72
Equity securities	240	—	46	286
Foreign government fixed income securities	—	5	—	5
Derivative assets:				
Commodity contracts	1,733	1,226	27	2,986
Total assets	$2,012	$1,372	$84	$3,468
Derivative liabilities:				
Commodity contracts	$1,601	$1,263	$25	$2,889
Interest rate contracts	—	134	—	134
Total liabilities	$1,601	$1,397	$25	$3,023

	As of December 31, 2011			
	Fair Value			
(In millions)	Level 1	Level 2	Level 3	Total
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$—	$—	$7	$7
Marketable equity securities	1	—	—	1
Trust fund investments:				
Cash and cash equivalents	2	—	—	2
U.S. government and federal agency obligations	44	—	—	44
Federal agency mortgage-backed securities	—	63	—	63
Commercial mortgage-backed securities	—	7	—	7
Corporate debt securities	—	54	—	54
Equity securities	209	—	42	251
Foreign government fixed income securities	—	4	—	4
Derivative assets:				
Commodity contracts	2,661	1,930	75	4,666
Total assets	$2,917	$2,058	$124	$5,099
Derivative liabilities:				
Commodity contracts	$2,757	$1,283	$67	$4,107
Interest rate contracts	—	108	—	108

Total liabilities	$2,757	$1,391	$67	$4,215

14

There were no transfers during the three and nine months ended September 30, 2012, and 2011, between Levels 1 and 2. The following tables reconcile, for the three and nine months ended September 30, 2012, and 2011, the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements at least annually using significant unobservable inputs:

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)							
	Three months ended September 30, 2012				Nine months ended September 30, 2012			
(In millions)	Debt Securities	Trust Fund Investments	Derivatives[(a)]	Total	Debt Securities	Trust Fund Investments	Derivatives[(a)]	Total
Beginning balance	$9	$43	$ 171	$223	$7	$ 42	$ 8	$57
Total gains/(losses) - realized/unrealized:								
Included in earnings	—	—	(9)	(9)	—	—	(3)	(3)
Included in OCI	2	—	—	2	4	—	—	4
Included in nuclear decommissioning obligations	—	3	—	3	—	3	—	3
Purchases	—	—	(109)	(109)	—	1	(1)	—
Transfers into Level 3 [(b)]	—	—	(31)	(31)	—	—	4	4
Transfers out of Level 3 [(b)]	—	—	(20)	(20)	—	—	(6)	(6)
Ending balance as of September 30, 2012	$11	$46	$ 2	$59	$11	$ 46	$ 2	$59
The amount of the total (losses)/gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held as of September 30, 2012	$—	$—	$ (5)	$(5)	$—	$ —	$ 1	$1

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)							
	Three months ended September 30, 2011				Nine months ended September 30, 2011			
(In millions)	Debt Securities	Trust Fund Investments	Derivatives[(a)]	Total	Debt Securities	Trust Fund Investments	Derivatives[(a)]	Total
Beginning balance	$9	$41	$ (26)	$24	$8	$ 39	$ (27)	$20
Total gains/(losses) - realized/unrealized:								
Included in earnings	—	—	—	—	—	—	19	19
Included in OCI	(1)	—	—	(1)	—	—	—	—
Included in nuclear decommissioning obligations	—	(8)	—	(8)	—	(7)	—	(7)
Purchases	—	—	(2)	(2)	—	1	6	7
Transfers into Level 3 [(b)]	—	—	13	13	—	—	(17)	(17)
Transfers out of Level 3 [(b)]	—	—	8	8	—	—	12	12
Ending balance as of September 30, 2011	$8	$33	$ (7)	$34	$8	$ 33	$ (7)	$34
The amount of the total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held as of September 30, 2011	$—	$—	$ (1)	$(1)	$—	$ —	$ 6	$6

(a) Consists of derivatives assets and liabilities, net.

(b) Transfers in/out of Level 3 are related to the availability of external broker quotes, and are valued as of the end of the reporting period. All transfers in/out are with Level 2.

Realized and unrealized gains and losses included in earnings that are related to the energy derivatives are recorded in operating revenues and cost of operations.

Derivative fair value measurements

The majority of NRG's contracts are exchange-traded contracts with readily available quoted market prices. A portion of NRG's contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company's prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote, then the mid-point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. A significant portion of the fair value of the Company's derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate those transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represent contracts for which external sources or observable market quotes are not available for the whole term or for certain delivery months or the contracts are retail and load following power contracts. These contracts are valued using various valuation techniques including but not limited to internal models that apply fundamental analysis of the market and corroboration with similar markets. Contracts valued with prices provided by models and other valuation techniques make up 1% of the total derivative assets and 1% of the total derivative liabilities.

The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that NRG's net exposure under a specific master agreement is an asset, the Company uses the counterparty's default swap rate. If the exposure under a specific master agreement is a liability, the Company uses NRG's default swap rate. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG's liabilities or that a market participant would be willing to pay for NRG's assets. As of September 30, 2012, the credit reserve resulted in a $9 million increase in fair value which is composed of a $4 million gain in Other Comprehensive Income, or OCI, and a $5 million gain in operating revenue and cost of operations. As of September 30, 2011, the credit reserve resulted in a $15 million decrease in fair value which is composed of a $5 million loss in OCI and a $10 million loss in operating revenue and cost of operations.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, Summary of Significant Accounting Policies, to the Company's 2011 Form 10-K, the following item is a discussion of the concentration of credit risk for the Company's contractual obligations. Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. NRG is exposed to counterparty credit risk through various activities including wholesale sales, fuel purchases and retail supply arrangements, and retail customer credit risk through its retail load activities.

Counterparty Credit Risk

The Company monitors and manages counterparty credit risk through credit policies that include: (i) an established credit approval process; (ii) daily monitoring of counterparties' credit limits; (iii) the use of credit mitigation measures such as margin, collateral, prepayment arrangements, or volumetric limits; (iv) the use of payment netting arrangements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risk surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty credit risk with a diversified portfolio of counterparties. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at

NRG to cover the credit risk of the counterparty until positions settle.

As of September 30, 2012, counterparty credit exposure to a portion of the Company's counterparties was $620 million and NRG held collateral (cash and letters of credit) against those positions of $28 million, resulting in a net exposure of $592 million. Counterparty credit exposure is valued through observable market quotes and discounted at the risk free rate. The following tables highlight net counterparty credit exposure by industry sector and by counterparty credit quality. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and Normal Purchase Normal Sale, or NPNS, and non-derivative transactions. The exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure [a] (% of Total)	
Financial institutions	46	%
Utilities, energy merchants, marketers and other	51	
Coal and emissions	1	
Independent System Operators, or ISOs	2	
Total as of September 30, 2012	100	%

Category	Net Exposure [a] (% of Total)	
Investment grade	63	%
Non-Investment grade	2	
Non-rated [b]	35	
Total as of September 30, 2012	100	%

(a) Counterparty credit exposure excludes uranium and coal transportation contracts because of the unavailability of market prices.

(b) For non-rated counterparties, the majority are related to ISO and municipal public power entities, which are considered investment grade equivalent ratings based on NRG's internal credit ratings.

NRG has counterparty credit risk exposure to certain counterparties representing more than 10% of total net exposure discussed above and the aggregate of such counterparties' exposure was $124 million. Approximately 83% of NRG's positions relating to this credit risk exposure roll-off by the end of 2013. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company's financial position or results of operations from nonperformance by any of NRG's counterparties.

Counterparty credit exposure described above excludes credit risk exposure under certain long term agreements, including California tolling agreements, South Central load obligations, and solar Power Purchase Agreements, or PPAs. As external sources or observable market quotes are not available to estimate such exposure, the Company valued these contracts based on various techniques including, but not limited to, internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Based on these valuation techniques, as of September 30, 2012, credit risk exposure to these counterparties attributable to NRG's ownership interests was approximately $1.1 billion for the next five years. This amount excludes potential credit exposures for projects with long term PPAs that have not reached commercial operations. Many of these power contracts are with utilities or public power entities that have strong credit quality and specific public utility commission or other regulatory support. These factors significantly reduce the risk of loss.

Retail Customer Credit Risk

NRG is exposed to retail credit risk through the Company's retail electricity providers, which serve commercial, industrial and governmental/institutional, or C&I, customers and the residential and small business, or mass, market. Retail credit risk results when a customer fails to pay for services rendered. The losses may result from both nonpayment of customer accounts receivable and the loss of in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of September 30, 2012, the Company's retail customer credit exposure was diversified across many customers and various industries, with a significant portion of the exposure with government entities.

Note 6 — Nuclear Decommissioning Trust Fund

NRG's nuclear decommissioning trust fund assets, which are for its portion of the decommissioning of the South Texas Project, or STP Units 1 & 2, are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. NRG accounts for the nuclear decommissioning trust fund in accordance with ASC 980, Regulated Operations, or ASC 980, because the Company's nuclear decommissioning activities are subject to approval by the PUCT with regulated rates that are designed to recover all decommissioning costs and that can be charged to and collected from the ratepayers per PUCT mandate. Since the Company is in compliance with PUCT rules and regulations regarding decommissioning trusts and the cost of decommissioning is the responsibility of the Texas ratepayers, not NRG, all realized and unrealized gains or losses (including other-than-temporary impairments) related to the Nuclear Decommissioning Trust Fund are recorded to the Nuclear Decommissioning Trust Liability and are not included in net income or accumulated other comprehensive income, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses (including other-than-temporary impairments) for the securities held in the trust funds, as well as information about the contractual maturities of those securities.

	As of September 30, 2012				As of December 31, 2011			
(In millions, except otherwise noted)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)
Cash and cash equivalents	$4	$—	$—	—	$2	$—	$—	—
U.S. government and federal agency obligations	33	2	—	11	43	3	—	10
Federal agency mortgage-backed securities	63	3	—	23	63	3	—	23
Commercial mortgage-backed securities	6	—	—	29	7	—	—	28
Corporate debt securities	72	4	—	11	54	3	1	10
Equity securities	286	143	—	—	251	113	1	—
Foreign government fixed income securities	5	—	—	6	4	—	—	8
Total	$469	$152	$—		$424	$122	$2	

The following table summarizes proceeds from sales of available-for-sale securities and the related realized gains and losses from these sales. The cost of securities sold is determined on the specific identification method.

	Nine months ended September 30,	
	2012	2011
	(In millions)	
Realized gains	$8	$4
Realized losses	5	3
Proceeds from sale of securities	316	294

Note 7 — Accounting for Derivative Instruments and Hedging Activities

This footnote should be read in conjunction with the complete description under Note 6, Accounting for Derivative Instruments and Hedging Activities, to the Company's 2011 Form 10-K.

Energy-Related Commodities

As of September 30, 2012, NRG had energy-related derivative financial instruments extending through 2015, which are designated as cash flow hedges.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company's issuance of variable and fixed rate debt. In order to manage the Company's interest rate risk, NRG enters into interest rate swap agreements. As of September 30, 2012, NRG had interest rate derivative instruments on recourse debt extending through 2013 and on non-recourse debt extending through 2030, the majority of which are designated as cash flow hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG's open derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of September 30, 2012, and December 31, 2011. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

Commodity	Units	Total Volume September 30, 2012	December 31, 2011
		(In millions)	
Emissions	Short Ton	(1)	(2)
Coal	Short Ton	34	37
Natural Gas	MMBtu	(244)	13
Oil	Barrel	—	1
Power	MWh	12	4
Interest	Dollars	$2,251	$2,121

Fair Value of Derivative Instruments

The following table summarizes the fair value within the derivative instrument valuation on the balance sheet:

	Fair Value Derivative Assets		Derivative Liabilities	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
	(In millions)			
Derivatives Designated as Cash Flow Hedges:				
Interest rate contracts current	$—	$—	$11	$39
Interest rate contracts long-term	—	—	96	68
Commodity contracts current	1	318	2	—
Commodity contracts long-term	—	—	1	1
Total Derivatives Designated as Cash Flow Hedges	1	318	110	108
Derivatives Not Designated as Cash Flow Hedges:				
Interest rate contracts current	—	—	13	—
Interest rate contracts long-term	—	—	14	1
Commodity contracts current	2,676	3,898	2,436	3,712
Commodity contracts long-term	309	450	450	394
Total Derivatives Not Designated as Cash Flow Hedges	2,985	4,348	2,913	4,107
Total Derivatives	$2,986	$4,666	$3,023	$4,215

Accumulated Other Comprehensive Income

The following table summarizes the effects of ASC 815, Derivatives and Hedging, or ASC 815, on the Company's accumulated OCI balance attributable to cash flow hedge derivatives, net of tax:

	Three months ended September 30, 2012			Nine months ended September 30, 2012		
	Energy Commodities	Interest Rate	Total	Energy Commodities	Interest Rate	Total
	(In millions)					
Accumulated OCI beginning balance	$111	$(68)	$43	$188	$(56)	$132
Reclassified from accumulated OCI to income:						
Due to realization of previously deferred amounts	(30)	3	(27)	(106)	11	(95)
Mark-to-market of cash flow hedge accounting contracts	(1)	(15)	(16)	(2)	(35)	(37)
Accumulated OCI ending balance, net of $12 tax	$80	$(80)	$—	$80	$(80)	$—
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $38 tax	$77	$(11)	$66	$77	$(11)	$66
Losses recognized in income from the ineffective portion of cash flow hedges	$—	$—	$—	$(51)	$—	$(51)

	Three months ended September 30, 2011			Nine months ended September 30, 2011		
	Energy Commodities	Interest Rate	Total	Energy Commodities	Interest Rate	Total
	(In millions)					
Accumulated OCI beginning balance	$332	$(40)	$292	$488	$(47)	$441
Reclassified from accumulated OCI to income:						
Due to realization of previously deferred amounts	(91)	—	(91)	(281)	11	(270)
Mark-to-market of cash flow hedge accounting contracts	19	(4)	15	53	(8)	45
Accumulated OCI ending balance, net of $136 tax	$260	$(44)	$216	$260	$(44)	$216
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $107 tax	$186	$(2)	$184	$186	$(2)	$184
Gains recognized in income from the ineffective portion of cash flow hedges	$9	$—	$9	$8	$3	$11

Amounts reclassified from accumulated OCI into income and amounts recognized in income from the ineffective portion of cash flow hedges are recorded to operating revenue for commodity contracts and interest expense for interest rate contracts.

Accounting guidelines require a high degree of correlation between the derivative and the hedged item throughout the period in order to qualify as a cash flow hedge. As of April 30, 2012, the Company's regression analysis for natural gas prices to ERCOT power prices, while positively correlated, did not meet the required threshold for cash flow hedge accounting for calendar year 2012. As a result, the Company de-designated its 2012 ERCOT cash flow hedges as of April 30, 2012, and prospectively marked these derivatives to market through the income statement.

Impact of Derivative Instruments on the Statement of Operations

Unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedges and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that have not been designated as cash flow hedges, ineffectiveness on cash flow hedges, and trading activity on the Company's statement of operations. The effect of commodity hedges is included within operating revenues and cost of operations and the effect of interest rate hedges is included in interest expense.

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2012	2011	2012	2011
Unrealized mark-to-market results				
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(85)	$50	$(160)	$72
Reversal of (gain)/loss positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions	(15)	(11)	5	60
Net unrealized (losses)/gains on open positions related to economic hedges	(159)	(7)	(78)	77
Gains/(losses) on ineffectiveness associated with open positions treated as cash flow hedges	—	9	(51)	8
Total unrealized mark-to-market (losses)/gains for economic hedging activities	(259)	41	(284)	217
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	(15)	8	(45)	22
Net unrealized (losses)/gains on open positions related to trading activity	(3)	—	33	22
Total unrealized mark-to-market(losses)/gains for trading activity	(18)	8	(12)	44
Total unrealized (losses)/gains	$(277)	$49	$(296)	$261

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2012	2011	2012	2011
Revenue from operations — energy commodities	$(395)	$89	$(470)	$193
Cost of operations	118	(40)	174	68
Total impact to statement of operations — energy commodities	$(277)	$49	$(296)	$261
Total impact to statement of operations — interest rate contracts	$—	$(1)	$(12)	$2

The reversal of gain or loss positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions were valued based upon the forward prices on the acquisition dates. The roll off amounts were offset by realized gains or losses at the settled prices and are reflected in the cost of operations during the same period.

For the nine months ended September 30, 2012, the unrealized loss from open economic hedge positions was primarily the result of a decrease in forward coal prices.

As of June 30, 2012 NRG had interest rate swaps designated as cash flow hedges on the Alpine solar project. The notional amount on the swaps exceeded the actual debt draws on the project. As such, NRG discontinued cash flow hedge accounting for these contracts and $4 million of loss previously deferred in OCI was recognized in earnings for the nine months ended September 30, 2012.

For the nine months ended September 30, 2011, the unrealized gain from open economic hedge positions was the result of an increase in value of forward purchases and sales of natural gas, electricity and fuel due to a decrease in forward power and gas prices.

Credit Risk Related Contingent Features

Certain of the Company's hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed “adequate assurance” under the agreements, or requires the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts with adequate assurance clauses that are in a net liability position as of September 30, 2012, was $91 million. The collateral required for contracts with credit rating contingent features was $51 million. The Company is also a party to certain marginable agreements where NRG has a net liability position, but the counterparty has not called for the collateral due, which was

approximately $56 million as of September 30, 2012.
See Note 5, Fair Value of Financial Instruments, to this Form 10-Q for discussion regarding concentration of credit risk.

Note 8 — Debt and Capital Leases

This footnote should be read in conjunction with the complete description under Note 12, Debt and Capital Leases, to the Company's 2011 Form 10-K.

Long-term debt and capital leases consisted of the following:

	September 30, 2012	December 31, 2011	Interest rate % [a]
	(In millions, except rates)		
NRG Recourse Debt:			
Senior notes, due 2023	$990	$—	6.625
Senior notes, due 2021	1,128	1,200	7.875
Senior notes, due 2020	1,100	1,100	8.250
Senior notes, due 2019	800	800	7.625
Senior notes, due 2019	692	691	8.500
Senior notes, due 2018	1,200	1,200	7.625
Senior notes, due 2017	270	1,090	7.375
Term loan facility, due 2018	1,577	1,588	L+3.00
Indian River Power LLC, tax-exempt bonds, due 2040	57	57	6.000
Indian River Power LLC, tax-exempt bonds, due 2045	157	148	5.375
Dunkirk Power LLC, tax-exempt bonds, due 2042	59	59	5.875
Fort Bend County, tax-exempt bonds, due 2038	16	—	Weekly per SIFMA rate [b]
Subtotal NRG Recourse Debt	8,046	7,933	
NRG Non-Recourse Debt:			
Ivanpah Financing:			
Solar Partners I, due 2014 and 2033	443	290	1.126 - 3.991
Solar Partners II, due 2014 and 2038	453	314	1.116 - 4.195
Solar Partners VIII, due 2014 and 2038	411	270	1.381 - 4.256
NRG Peaker Finance Co. LLC, bonds, due 2019	194	190	L+1.07
Agua Caliente Solar, LLC, due 2037	541	181	2.395 - 3.256
NRG West Holdings LLC, term loan, due 2023	294	159	L+2.25 - 2.75
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013, 2017 and 2025	141	151	5.95 - 7.31
CVSR - High Plains Ranch II LLC, due 2037	548	—	0.611 - 2.639
South Trent Wind LLC, financing agreement, due 2020	73	75	L+2.50 - 2.625
Solar Power Partners - SPP Fund II/IIB LLC term loans, due 2017	15	17	L+3.50
Solar Power Partners - SPP Fund III LLC term loan, due 2024	40	42	L+3.50
NRG Solar Roadrunner LLC, due 2031	46	61	L+2.01
NRG Solar Blythe LLC, credit agreement, due 2028	26	27	L+2.50
NRG Solar Avra Valley LLC	40	—	L+2.25
Other	31	19	various
Subtotal NRG Non-Recourse Debt	3,296	1,796	
Subtotal long-term debt	11,342	9,729	
Capital leases:			
	—	103	

Saale Energie GmbH, Schkopau capital lease, due 2021		
Subtotal	11,342	9,832
Less current maturities	374	87
Total long-term debt and capital leases	$10,968	$9,745

(a) L+ equals LIBOR plus x%.
(b) Securities Industry and Financial Markets Association, or SIFMA

22

Issuance of 2023 Senior Notes

6.625% 2023 Senior Notes

On September 24, 2012, NRG issued $990 million aggregate principal amount at par of 6.625% Senior Notes due 2023, or the 2023 Senior Notes. The 2023 Senior Notes were issued under an Indenture, dated February 2, 2006, between NRG and Law Debenture Trust Company of New York, as trustee, as amended through a Supplemental Indenture, which is discussed in Note 12, Debt and Capital Leases, in the Company's 2011 Form 10-K. The Indenture and the form of the note provide, among other things, that the 2023 Senior Notes will be senior unsecured obligations of NRG.

The proceeds, net of issuance costs, of $978 million for the 2023 Senior Notes will be used to complete the tender offer of the 2017 Senior Notes, as discussed below. Interest is payable semi-annually beginning on March 15, 2013, until the maturity date of March 15, 2023.

Prior to September 15, 2015, NRG may redeem up to 35% of the aggregate principal amount of the 2023 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 106.625% of the principal amount. Prior to September 15, 2017, NRG may redeem all or a portion of the 2023 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.313% of the note, plus interest payments due on the note from the date of redemption through September 15, 2017, discounted at a Treasury rate plus 0.50%. In addition, on or after September 15, 2017, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
September 15, 2017 to September 14, 2018	103.313	%
September 15, 2018 to September 14, 2019	102.208	%
September 15, 2019 to September 14, 2020	101.104	%
September 15, 2020 and thereafter	100.000	%

In connection with the 2023 Senior Notes, NRG entered into a registration payment arrangement. For the first 90-day period immediately following a registration default, additional interest will be paid in an amount equal to 0.25% per annum of the principal amount of 2023 Senior Notes outstanding, as applicable. The amount of interest paid will increase by an additional 0.25% per annum with respect to each subsequent 90-day period until all registration defaults are cured, up to a maximum amount of interest of 1.0% per annum of the principal amount of the 2023 Senior Notes outstanding, as applicable. The additional interest is paid on the next scheduled interest payment date and following the cure of the registration default, the additional interest payment will cease.

Redemption of 2017 Senior Notes

On September 24, 2012, the Company redeemed $820 million of the 2017 Senior Notes through a tender offer, at an early redemption percentage of 104.125%. On October 9, 2012, an additional $0.4 million was tendered at a redemption percentage of 101.125%, and on October 24, 2012, the remaining $270 million of the 2017 Senior Notes were called, at a redemption percentage of 103.688%. Accordingly, the $270 million still outstanding as of September 30, 2012 was reclassified to current portion of long-term debt on the consolidated balance sheet. A loss on the extinguishment of the 2017 Senior Notes of $41 million was recorded during the three months ended September 30, 2012, and an additional $10 million was recorded in October, 2012; these losses primarily consisted of the premiums paid on the redemption and the write-off of previously deferred financing costs.

Fort Bend County Tax-Exempt Bonds

On May 3, 2012, NRG executed a $54 million tax-exempt bond financing with a maturity date of May 1, 2038, issued by the Fort Bend County Industrial Development Corporation, or the Fort Bend County Tranche A Bonds. The Fort Bend County Tranche A Bonds will be used for the construction of a peaking unit with one or more components of a carbon capture system at the W.A. Parish Generating Station in Thompsons, TX, or W.A. Parish. The bonds initially bore weekly interest based on the SIFMA rate, and were enhanced by a letter of credit under the Company's 2011 Revolving Credit Facility covering amounts drawn. The proceeds drawn through September 30, 2012 were $16 million, and the remaining balance will be drawn over time as construction and other qualifying costs are paid.

On October 18, 2012, NRG fixed the rate on the Fort Bend County Tranche A Bonds at 4.75% payable semiannually, and the letter of credit was canceled and replaced with an NRG guarantee. Also, the holders no longer have the option to tender the bonds at any time; accordingly, the outstanding balance as of September 30, 2012 was reclassified to long-term debt on the consolidated balance sheet.

On October 18, 2012, NRG also executed an additional $73 million tax-exempt bond financing, with a maturity date of November 1, 2042, also issued by the Fort Bend County Industrial Development Corporation, or the Fort Bend County Tranche B Bonds. The Fort Bend County Tranche B Bonds will be used for environmental and maintenance upgrades at W.A. Parish. The bonds were issued at a fixed rate of 4.75% payable semiannually, and are supported by an NRG guarantee. The proceeds will be drawn over time as qualifying expenditures are paid.

NRG Repowering Holdings LLC

On January 25, 2012, NRG Repowering Holdings LLC, or NRG Repowering, terminated its revolving credit facility, repaid the $5 million then outstanding, and a supporting letter of credit issued by NRG was returned.

On January 25, 2012, NRG Repowering entered into a Credit and Reimbursement Agreement which provides for a $10 million working capital facility that can be used for general corporate purposes or to issue letters of credit, and an $80 million letter of credit facility. Interest on the letters of credit accrues at 3.5% and on loans under the working capital facility at the London Inter-Bank Offered Rate, or LIBOR, plus 3.50%. The facility is secured by NRG Repowering's investments in GenConn Energy LLC and South Trent Wind LLC, and matures January 25, 2015. As of September 30, 2012, NRG Repowering had issued a $10 million letter of credit under the working capital facility and $80 million in letters of credit under the letter of credit facility.

Alpine Financing

On March 16, 2012, NRG, through its wholly-owned subsidiary, NRG Solar Alpine LLC, or Alpine, entered into a credit agreement with a group of lenders, or the Alpine Financing Agreement, for a $166 million construction loan that will convert to a term loan upon completion of the project and a $68 million cash grant loan. The construction loan has an interest rate of LIBOR plus an applicable margin of 2.50% and the cash grant loan has an interest rate of LIBOR plus an applicable margin of 2.25%. The term loan has an interest rate of LIBOR plus an applicable margin of 2.50%, which escalates 0.25% on the fifth anniversary of the term conversion. The term loan, which is secured by all the assets of Alpine, matures on the 10^{th} anniversary of the term conversion and amortizes based upon a predetermined schedule. The cash grant loan matures upon the earlier of the receipt of the cash grant or February 2013. The Alpine Financing Agreement also includes a letter of credit facility on behalf of Alpine of up to $37 million. Alpine pays an availability fee of 100% of the applicable margin on issued letters of credit. As of September 30, 2012, $2 million was outstanding under the construction loan, nothing was outstanding under the cash grant loans, and $10 million in letters of credit in support of the project were issued.

Also related to the Alpine Financing Agreement, on March 16, 2012, Alpine entered into a series of fixed for floating interest rate swaps for at least 85% of the outstanding term loan amount, intended to hedge the risks associated with floating interest rates. Alpine will pay its counterparty the equivalent of a 2.74% fixed interest payment on a predetermined notional value, and Alpine will receive quarterly the equivalent of a floating interest payment based on a one month LIBOR calculated on the same notional value through December 31, 2012 and based on a three month LIBOR from December 31, 2012 through the term loan maturity date. All interest rate swap payments by Alpine and its counterparty are made monthly through December 31, 2012, and quarterly thereafter and the LIBOR rate is determined in advance of each interest period. The notional amount of the swap, which became effective March 31, 2012, and matures on December 31, 2029, was $141 million as of September 30, 2012 and will increase and amortize in proportion to the loan.

Roadrunner Financing

On March 20, 2012, NRG, through its wholly-owned subsidiary, NRG Roadrunner LLC, or Roadrunner, received proceeds of $21 million under its cash grant application. These proceeds were used to repay Roadrunner's cash grant loan of $17 million plus accrued interest. The remaining cash was returned to NRG under the terms of the accounts agreement.

CVSR Financing

On March 9, 2012, NRG, through its wholly-owned subsidiary, High Plains Ranch II LLC, completed its first borrowing of $138 million under the CVSR Financing Agreement with the Federal Financing Bank. As of September 30, 2012, $548 million was outstanding under the loan.

Avra Valley Financing

On August 30, 2012, NRG, through its wholly-owned subsidiary, NRG Solar Avra Valley LLC, or Avra Valley, entered into a credit agreement with a bank, or the Avra Valley Financing Agreement, for a $66 million construction loan that will convert to a term loan upon completion of the project and an $8 million cash grant loan. Both the construction and cash grant loans have interest rates of LIBOR plus an applicable margin of 2.25%. The term loan has an interest rate of LIBOR plus an applicable margin of 2.25%, which escalates 0.25% on the fifth, tenth, and fifteenth anniversary of the term conversion. The term loan, which is secured by all the assets of Avra Valley, matures on the 18th anniversary of the term conversion and amortizes based upon a predetermined schedule. The cash grant loan matures upon the earlier of three days after the receipt of the cash grant or May 2013. The Avra Valley Financing Agreement also includes a letter of credit facility on behalf of Avra Valley of up to $4 million. Avra Valley pays an availability fee of 100% of the applicable margin on issued letters of credit. As of September 30, 2012, $40 million was outstanding under the construction loan, nothing was outstanding under the cash grant loans, and no letters of credit in support of the project were issued.

Also related to the Avra Valley Financing Agreement, on August 30, 2012, Avra Valley entered into a fixed for floating interest rate swap for at least 90% of the outstanding term loan amount, intended to hedge the risks associated with floating interest rates. Avra Valley will pay its counterparty the equivalent of a 2.333% fixed interest payment on a predetermined notional value, and Avra Valley will receive quarterly the equivalent of a floating interest payment based on a 3 month LIBOR calculated on the same notional value through the term loan maturity date. All interest rate swap payments by Avra Valley and its counterparty are made quarterly and the LIBOR rate is determined in advance of each interest period. The original notional amount of the swap, which becomes effective November 30, 2012, and matures on November 30, 2030 is $59 million and will amortize in proportion to the loan.

Note 9 — Variable Interest Entities, or VIEs

NRG has interests in entities that are considered VIEs under ASC 810, Consolidation, but NRG is not considered the primary beneficiary. NRG accounts for its interests in these entities under the equity method of accounting.

GenConn Energy LLC — Through its subsidiary, NRG Connecticut Peaking Development LLC, NRG owns a 50% interest in GenConn, a limited liability company which owns and operates two 200 MW peaking generation facilities in Connecticut at NRG's Devon and Middletown sites. NRG's maximum exposure to loss is limited to its equity investment, which was $125 million as of September 30, 2012.

Sherbino I Wind Farm LLC — NRG owns a 50% interest in Sherbino, a joint venture with BP Wind Energy North America Inc. NRG's maximum exposure to loss is limited to its equity investment, which was $92 million as of September 30, 2012.

Texas Coastal Ventures, LLC — NRG owns a 50% interest in Texas Coastal Ventures, a joint venture with Hilcorp Energy I, L.P., through its subsidiary Petra Nova LLC. NRG's maximum exposure to loss is limited to its equity investment, which was $53 million as of September 30, 2012.

Note 10 — Changes in Capital Structure

As of September 30, 2012, and December 31, 2011, the Company had 500,000,000 shares of common stock authorized. The following table reflects the changes in NRG's common shares issued and outstanding:

	Issued	Treasury	Outstanding
Balance as of December 31, 2011	304,183,720	(76,664,199)	227,519,521
Shares issued under LTIP	608,128	—	608,128
Shares issued under ESPP	—	158,481	158,481

Balance as of September 30, 2012	304,791,848	(76,505,718)	228,286,130

Employee Stock Purchase Plan — On April 25, 2012, NRG shareholders approved an increase of 1,000,000 shares available for issuance under the NRG Energy, Inc. Employee Stock Purchase Plan, or ESPP. At September 30, 2012, 1,018,870 shares of treasury stock were available for issuance under the ESPP.

Common Stock Dividends — On August 15, 2012, NRG paid its first quarterly dividend on the Company's common stock of $0.09 per share. On October 15, 2012, NRG declared a quarterly dividend on the Company's common stock of $0.09 per share, payable November 15, 2012, to shareholders of record as of November 1, 2012.

Note 11 — (Loss)/Earnings Per Share

Basic (loss)/earnings per common share is computed by dividing net (loss)/earnings less accumulated preferred stock dividends by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted (loss)/earnings per share is computed in a manner consistent with that of basic (loss)/earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period.

The reconciliation of NRG's basic and diluted (loss)/earnings per share is shown in the following table:

	Three months ended September 30,		Nine months ended September 30,	
(In millions, except per share data)	2012	2011	2012	2011
Basic (loss)/earnings per share attributable to NRG common stockholders				
Numerator:				
Net (loss)/income attributable to NRG Energy, Inc.	$(1)	$(55)	$43	$306
Preferred stock dividends	(2)	(2)	(7)	(7)
Net (loss)/income attributable to NRG Energy, Inc. available to common stockholders	$(3)	$(57)	$36	$299
Denominator:				
Weighted average number of common shares outstanding	228	240	228	243
Basic (loss)/earnings per share:				
Net (loss)/income attributable to NRG Energy, Inc.	$(0.01)	$(0.24)	$0.16	$1.23
Diluted (loss)/earnings per share attributable to NRG common stockholders				
Numerator:				
Net (loss)/income attributable to NRG Energy, Inc. available to common shareholders	$(3)	$(57)	$36	$299
Denominator:				
Weighted average number of common shares outstanding	228	240	228	243
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	—	—	2	2
Total dilutive shares	228	240	230	245
Diluted (loss)/earnings per share:				
Net (loss)/income attributable to NRG Energy, Inc.	$(0.01)	$(0.24)	$0.16	$1.22

The following table summarizes NRG’s outstanding equity instruments that are anti-dilutive and were not included in the computation of the Company’s diluted (loss)/earnings per share:

	Three months ended September 30,		Nine months ended September 30,	
(In millions of shares)	2012	2011	2012	2011
Equity compensation plans	11	7	6	7
Embedded derivative of 3.625% redeemable perpetual preferred stock	16	16	16	16
Total	27	23	22	23

Note 12 — Segment Reporting

Effective in fiscal year 2012, NRG's segment structure and its allocation of corporate expenses were updated to reflect how management currently makes financial decisions and allocates resources. The Company has recast the data from prior periods to reflect this change in reportable segments to conform to the current year presentation. The Company's businesses are primarily segregated based on the Retail businesses, conventional power generation, alternative energy businesses and corporate activities. Within NRG's conventional power generation operations, there are distinct components with separate operating results and management structures for the following geographical regions: Texas, Northeast, South Central, West and Other, which includes its international businesses, thermal and chilled water business and maintenance services. The Company's alternative energy businesses include solar and wind assets, electric vehicle services and the carbon capture business. Intersegment sales are accounted for at market.

(In millions)		Conventional Power Generation								
Three months ended September 30, 2012	Retail[a]	Texas[a]	North-east[a]	South Central	West	Other[a]	Alternative Energy[a]	Corporate[a][b]	Elimination	Total
Operating revenues	$1,856	$877	$274	$270	$87	$68	$56	$ 4	$ (1,161)	$2,331
Depreciation and amortization	41	115	32	23	3	4	18	3	—	239
Equity in earnings/(loss) of unconsolidated affiliates	—	—	3	—	4	2	(5)	—	—	4
(Loss)/income before income taxes	(300)	299	33	19	35	9	—	(200)	—	(105)
Net (loss)/income attributable to NRG Energy, Inc.	$(300)	$299	$33	$19	$35	$9	$(9)	$ (87)	$—	$(1)
Total assets	$3,179	$12,109	$1,945	$1,676	$909	$692	$5,615	$ 18,076	$ (16,981)	$27,220

[a] Includes intersegment sales and derivative gains and losses of: $3 $1,126 $6 $— $— $12 $10 $4

[b] Includes loss on debt extinguishment of $41 million.

(In millions)		Conventional Power Generation								
Three months ended September 30, 2011	Retail[c]	Texas[c][d]	North-east[c]	South Central	West	Other[c]	Alternative Energy[c]	Corporate[c][e]	Elimination	Total
Operating revenues	$1,861	$817	$ 298	$279	$45	$81	$10	$ 5	$ (722)	$2,674
Depreciation and amortization	48	117	33	23	2	4	7	4	—	238
Equity in earnings/(loss) of unconsolidated affiliates	—	—	4	—	4	3	6	(1)	—	16
	36	(45)	6	21	27	7	(12)	(175)	—	(135)

Income/(loss) before income taxes										
Net income/(loss) attributable to NRG Energy, Inc.	$36	$(45)	$ 6	$21	$27	$5	$(12)	$ (93)	$ —	$(55)
[c] Includes intersegment sales and derivative gains and losses of:	$4	$697	$3	$—	$—	$6	$5	$5		

[d] Includes impairment charge on emission allowances of $160 million.
[e] Includes loss on debt extinguishment of $32 million.

27

(In millions)		Conventional Power Generation								
Nine months ended September 30, 2012	Retail[f]	Texas[f]	North-east[f]	South Central	West	Other[f]	Alternative Energy[f]	Corporate[f][g]	Elimination	Total
Operating revenues	$4,492	$1,462	$ 598	$653	$185	$262	$114	$ 11	$ (1,418)	$6,359
Depreciation and amortization	126	343	96	69	8	12	41	8	—	703
Equity in earnings of unconsolidated affiliates	—	—	11	—	6	8	1	—	—	26
Income/(loss) before income taxes	504	(202)	(20)	—	42	29	(22)	(516)	—	(185)
Net income/(loss) attributable to NRG Energy, Inc.	$504	$(202)	$ (20)	$—	$42	$25	$(40)	$ (266)	$ —	$43
[f] Includes intersegment sales and derivative gains and losses of:	$3	$1,287	$51	$—	$—	$55	$18	$4		

[g] Includes loss on debt extinguishment of $41 million.

(In millions)		Conventional Power Generation								
Nine months ended September 30, 2011	Retail[h]	Texas[h][i]	North-east[h]	South Central	West	Other[h]	Alternative Energy[h]	Corporate[h][j]	Elimination	Total
Operating revenues	$4,409	$2,149	$ 770	$656	$122	$244	$33	$ 9	$ (1,445)	$6,947
Depreciation and amortization	114	347	89	65	7	11	22	10	—	665
Equity in earnings/(losses) of unconsolidated affiliates	—	—	9	—	9	9	—	(1)	—	26
Income/(loss) before income taxes	347	193	(13)	46	51	20	(42)	(1,111)	—	(509)
Net income/(loss)attributable to NRG Energy, Inc.	$350	$193	$ (13)	$46	$51	$14	$(42)	$ (293)	$ —	$306
[h] Includes intersegment sales and derivative gains and losses of:	$4	$1,401	$5	$—	$—	$15	$13	$5		

[i] Includes impairment charge on emission allowances of $160 million.

[j] Includes impairment charge on investment of $495 million, loss on debt extinguishment of $175 million, and tax benefit of $633 million resulting from the resolution of the federal tax audit.

Note 13 — Income Taxes

Effective Tax Rate

The income tax provision consisted of the following:

	Three months ended September 30,		Nine months ended September 30,	
(In millions except otherwise noted)	2012	2011	2012	2011
Loss before income taxes	$(105)	$(135)	$(185)	$(509)
Income tax benefit	(113)	(80)	(246)	(815)
Effective tax rate	107.6 %	59.3 %	133.0 %	160.1 %

For the three and nine months ended September 30, 2012, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the income tax benefits resulting from generation of ITCs from the Company's Agua Caliente solar project in Arizona and production tax credits, or PTCs, generated from certain Texas wind facilities.

For the three and nine months ended September 30, 2011, NRG's overall effective tax rate for both of these periods was different than the statutory rate of 35% primarily due to the recognition of previously uncertain tax benefits that were effectively settled upon audit examination for years 2004 through 2006 and that were mainly composed of net operating losses of $536 million, which had been classified as capital loss carryforwards for financial statement purposes.

Uncertain tax benefits

As of September 30, 2012, NRG has recorded a non-current tax liability of $67 million for uncertain tax benefits from positions taken on various state tax returns, including accrued interest. NRG has accrued interest related to these uncertain tax benefits of $2 million for the nine months ended September 30, 2012, and has accrued $15 million of interest and penalties since adoption. The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense.

The Company is currently under federal examination for tax years 2007 through 2010 and continues to be under examination by various state and foreign tax jurisdictions for multiple years.

Tax Receivable and Payable

As of September 30, 2012, NRG recorded a current domestic tax receivable of $52 million, of which $24 million is related to federal cash grants filed, $18 million is related to property tax refunds as a result of the New York State Empire Zone program and $10 million relates to Federal income tax refunds for prior year tax return filings. As of September 30, 2012, NRG has a current tax payable of $15 million that represents a tax liability due for domestic state taxes of $13 million, as well as foreign taxes payable of $2 million. In addition, we have recorded a $51 million non-current asset for Empire Zone credits generated in 2010 through 2012, for which the receipt of cash is deferred pursuant to New York State law.

Note 14 — Commitments and Contingencies

Commitments

First Lien Structure

NRG has granted first liens to certain counterparties on substantially all of the Company's assets to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or MWh equivalents. The Company's lien counterparties may have a claim on NRG's assets to the extent market prices exceed the hedged price. As of September 30, 2012, in aggregate, the hedge portfolio under the lien was in-the-money.

Contingencies

Set forth below is a description of the Company's material legal proceedings. The Company believes that it has valid defenses to these legal proceedings and intends to defend them vigorously. Pursuant to the requirements of ASC 450, Contingencies and related guidance, NRG records reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition, legal costs are expensed as incurred. Management has assessed each of the following matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, the Company is unable to predict the outcome of these legal proceedings or reasonably estimate the scope or amount of any associated costs and potential liabilities. As additional information becomes available, management adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of the Company's liabilities and contingencies could be at amounts that are different from its currently recorded reserves and that such difference could be material.

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect NRG's consolidated financial position, results of operations, or cash flows.

California Department of Water Resources

This matter concerns, among other contracts and other defendants, the California Department of Water Resources, or CDWR, and its wholesale power contract with subsidiaries of WCP (Generation) Holdings, Inc., or WCP. The case originated with a February 2002 complaint filed by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State of California. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that the FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, the FERC rejected this complaint, denied rehearing, and the case was appealed to the U.S. Court of Appeals for the Ninth Circuit where oral argument was held on December 8, 2004.

On December 19, 2006, the Ninth Circuit decided that in the FERC's review of the contracts at issue, the FERC could not rely on the Mobile-Sierra standard presumption of just and reasonable rates, where such contracts were not reviewed by the FERC with full knowledge of the then existing market conditions. WCP and others sought review by the U.S. Supreme Court. WCP's appeal was not selected, but instead held by the Supreme Court. In the appeal that was selected by the Supreme Court, on June 26, 2008, the Supreme Court ruled: (i) that the Mobile-Sierra public interest standard of review applied to contracts made under a seller's market-based rate authority; (ii) that the public interest "bar" required to set aside a contract remains a very high one to overcome; and (iii) that the Mobile-Sierra presumption of contract reasonableness applies when a contract is formed during a period of market dysfunction unless (a) such market conditions were caused by the illegal actions of one of the parties or (b) the contract negotiations were tainted by fraud or duress. In this related case, the U.S. Supreme Court affirmed the Ninth Circuit's decision agreeing that the case should be remanded to the FERC to clarify the FERC's 2003 reasoning regarding its rejection of the original complaint relating to the financial burdens under the contracts at issue and to alleged market manipulation at the time these contracts were formed. As a result, the U.S. Supreme Court then reversed and remanded the WCP CDWR case to the Ninth Circuit for treatment consistent with its June 26, 2008, decision in the related case. On October 20, 2008, the Ninth Circuit asked the parties in the remanded CDWR case, including WCP and the FERC, whether that Court should answer a question the U.S. Supreme Court did not address in its June 26, 2008, decision; whether the Mobile-Sierra doctrine applies to a third-party that was not a signatory to any of the wholesale power contracts, including the CDWR contract, at issue in that case. Without answering that reserved question, on December 4, 2008, the Ninth Circuit vacated its prior opinion and remanded the WCP CDWR case back to the FERC for proceedings consistent with the U.S. Supreme Court's June 26, 2008, decision. On December 15, 2008, WCP and the other seller-defendants filed with the FERC a Motion for Order Governing Proceedings on Remand. On January 14, 2009, the CPUC filed an Answer and Cross Motion for an Order Governing Procedures on Remand and on January 28, 2009, WCP and the other seller-defendants filed their reply. At this time, the FERC has not acted on remand.

On January 14, 2010, the U.S. Supreme Court issued its decision in an unrelated proceeding involving the Mobile-Sierra doctrine that will affect the standard of review applied to the CDWR contract on remand before the FERC. In NRG Power Marketing v. Maine Public Utilities Commission, the Supreme Court held that the Mobile-Sierra presumption regarding the reasonableness of contract rates does not depend on the identity of the complainant who seeks a FERC investigation/refund.

As part of the 2006 acquisition of Dynegy's 50% ownership interest in WCP, WCP and NRG assumed responsibility for any risk of loss arising from this case, unless any such loss was deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally between WCP and Dynegy.

On March 22, 2012, NRG reached an agreement in principle with the CPUC to settle and resolve this matter, including all related claims, on behalf of NRG and on behalf of Dynegy. The agreement in principle was announced by the Company on March 23, 2012, as well as by the CPUC and by the California Governor's Office. The documented agreement was executed and submitted to the FERC on April 27, 2012 for its approval, and remains pending. The settlement agreement contains three material elements to be fulfilled over a four to six year period, depending upon several factors. First, the settlement agreement includes a $20 million cash payment due 30 days after the FERC approval. Second, it includes the construction and operation of a fee-based charging network, to be owned and operated by NRG subsidiary, eVgo, which will consist of at least 200 publicly available fast-charging electric vehicle stations installed at locations across California. Last, it calls for the wiring and associated work required to improve at least 10,000 individual parking spaces to allow for the charging of electric vehicles in at least 1,000 multi-family complexes, worksites, and public interest locations such as community colleges, public universities, and public or non-profit hospitals. Although these improved newly wired parking spaces will continue to be owned by the local property owner, eVgo will have an 18-month exclusive right to obtain customers from these locations starting from the date of each completed installation. The expected $20 million cash payment was accrued and expensed in the statement of operations for the three months ended March 31, 2012. In addition, the Company expects to spend approximately $100 million over the next four to six year period, during which the Company will fulfill the other elements of the settlement, and will capitalize a substantial majority of the costs as property, plant and equipment, representing the costs to construct the charging network and the wiring, which will be productive assets. The Company will expense the costs to operate the assets as incurred. On May 24, 2012, ECOtality, Inc. filed a lawsuit against the CPUC challenging the settlement, which was effectively dismissed on October 12, 2012.

Louisiana Generating, LLC

On February 11, 2009, the U.S. Department of Justice, or U.S. DOJ, acting at the request of the U.S. Environmental Protection Agency, or U.S. EPA, commenced a lawsuit against Louisiana Generating, LLC, or LaGen, in federal district court in the Middle District of Louisiana alleging violations of the Clean Air Act, or CAA, at the Big Cajun II power plant. This is the same matter for which Notices of Violation, or NOVs, were issued to LaGen on February 15, 2005, and on December 8, 2006. Specifically, it is alleged that in the late 1990's, several years prior to NRG's acquisition of the Big Cajun II power plant from the Cajun Electric bankruptcy and several years prior to the NRG bankruptcy, modifications were made to Big Cajun II Units 1 and 2 by the prior owners without appropriate or adequate permits and without installing and employing the best available control technology, or BACT, to control emissions of nitrogen oxides and/or sulfur dioxides. The relief sought in the complaint includes a request for an injunction to: (i) preclude the operation of Units 1 and 2 except in accordance with the CAA; (ii) order the installation of BACT on Units 1 and 2 for each pollutant subject to regulation under the CAA; (iii) obtain all necessary permits for Units 1 and 2; (iv) order the surrender of emission allowances or credits; (v) conduct audits to determine if any additional modifications have been made which would require compliance with the CAA's Prevention of Significant Deterioration program; (vi) award to the U.S. DOJ its costs in prosecuting this litigation; and (vii) assess civil penalties of up to $27,500 per day for each CAA violation found to have occurred between January 31, 1997, and March 15, 2004, up to $32,500 for each CAA violation found to have occurred between March 15, 2004, and January 12, 2009, and up to $37,500 for each CAA violation found to have occurred after January 12, 2009.

On April 27, 2009, LaGen filed an objection in the Cajun Electric Cooperative Power, Inc.'s bankruptcy proceeding in the U.S. Bankruptcy Court for the Middle District of Louisiana to seek to prevent the bankruptcy from closing. LaGen also filed a complaint, or adversary proceeding, in the same bankruptcy proceeding, seeking a judgment that: (i) it did not assume liability from Cajun Electric for any claims or other liabilities under environmental laws with respect to Big Cajun II that arose, or are based on activities that were undertaken, prior to the closing date of the acquisition; (ii) it is not otherwise the successor to Cajun Electric with respect to environmental liabilities arising prior to the acquisition; and (iii) Cajun Electric and/or the Bankruptcy Trustee are exclusively liable for any of the violations alleged in the February 11, 2009 lawsuit to the extent that such claims are determined to have merit. On April 15, 2010, the bankruptcy court signed an order granting LaGen's stipulation of voluntary dismissal without prejudice of the adversary proceeding. The bankruptcy proceeding has since closed.

On January 17, 2012, LaGen filed a demand for a jury trial. On January 20, 2012, the court scheduled a liability-phase trial for October 15, 2012, and a remedy-phase trial set to occur at a later date to be determined in the event of an adverse decision in a liability-phase trial. On October 17, 2012, prior to the start of the liability-phase trial which had been temporarily adjourned, the parties notified the court that they had reached an agreement on terms of a settlement which requires final approval by the U.S. DOJ. The terms of the agreement generally require LaGen to install certain emission control technologies, as well as pay a civil penalty of $3.5 million and complete mitigation projects of $10.5 million within five years of entry of the Consent Decree. The Company anticipates entry of a Consent Decree by the court approximately ninety days after lodging. The Company is adequately reserved for this settlement. Further discussion on this matter can be found in Note 16, Environmental Matters - South Central Region, of this Form 10-Q.

In a related matter, soon after the filing of the above referenced U.S. DOJ lawsuit, LaGen sought insurance coverage from its insurance carrier, Illinois Union Insurance Company, or ILU. ILU denied coverage and thereafter LaGen filed a lawsuit (which was consolidated with a prior suit filed by ILU) seeking a declaration that ILU must provide coverage to LaGen for the defense costs incurred in defending the U.S. DOJ lawsuit. LaGen and ILU both filed motions for summary judgment and on January 30, 2012, the court issued an order granting LaGen's motion finding that ILU has a duty to defend LaGen. The trial court certified the summary judgment for immediate interlocutory appeal, and on May 25, 2012, ILU filed a petition with the U.S. Circuit Court of Appeals for the Fifth Circuit seeking to appeal the trial court's summary judgment ruling. The Fifth Circuit granted the petition on September 4, 2012. ILU filed a related notice of appeal on June 14, 2012, which also seeks review of the trial court's summary judgment ruling. The Company filed a motion to consolidate the two appeals which the court granted on October 24, 2012. Briefing on the appeals is currently ongoing.

Energy Plus Holdings, LLC Purported Class Actions

Energy Plus Holdings, LLC, or Energy Plus, is a defendant in five purported class action lawsuits, one in New York, one in New Jersey, one in Maryland and two in Pennsylvania. The plaintiffs in those lawsuits generally allege that Energy Plus misrepresents that its rates are competitive in the market; fails to disclose that its rates are substantially higher than those in the market and that Energy Plus has engaged in deceptive practices in its marketing of energy services. Plaintiffs generally seek that these matters be certified as class actions, with treble damages, interest, costs, attorneys' fees, and any other relief that the court deems just and proper. In addition, on July 26, 2012, the Connecticut Attorney General and Office of Consumer Counsel filed a petition with the Connecticut Public Utilities Regulatory Authority seeking to investigate Energy Plus' marketing practices. On August 7, 2012, Energy Plus Holdings LLC and Energy Plus Natural Gas LLC received a subpoena from the State of New York Office of Attorney General which generally seeks information and business records related to Energy Plus' sales, marketing and business practices. While we believe that these allegations are without merit, we are cooperating with the attorneys general and are exploring an amicable resolution of all matters. The Company does not currently anticipate any potential resolution to be material in nature and believes it is adequately reserved for any estimated losses.

Purported Class Actions related to July 22, 2012 Announcement of NRG/GenOn Merger Agreement

NRG Energy, Inc. has been named as a defendant in eight purported class actions pending in Texas and Delaware, related to its announcement of its agreement to acquire all outstanding shares of GenOn. These cases have been consolidated into one state court case in each of Delaware and Texas and a federal court case in Texas. The plaintiffs generally allege breach of fiduciary duties, as well as conspiracy, aiding and abetting breaches of fiduciary duties. Plaintiffs are generally seeking to: be certified as a class; enjoin the merger; direct the defendant to exercise their fiduciary duties; rescind the acquisition and be awarded attorneys' fees costs and other relief that the court deems appropriate. Plaintiffs have demanded that there be additional disclosures regarding the merger terms. On October 24, 2012, the parties to the Delaware state court case executed a Memorandum of Understanding to resolve the Delaware purported class action lawsuit.

Note 15 — Regulatory Matters

NRG operates in a highly regulated industry and is subject to regulation by various federal and state agencies. As such, NRG is affected by regulatory developments at both the federal and state levels and in the regions in which NRG operates. In addition, NRG is subject to the market rules, procedures, and protocols of the various Independent System Operator, or ISO, markets in which NRG participates. These power markets are subject to ongoing legislative and regulatory changes that may impact NRG's wholesale and retail businesses.

In addition to the regulatory proceedings noted below, NRG and its subsidiaries are a party to other regulatory proceedings arising in the ordinary course of business or have other regulatory exposure. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect NRG's consolidated financial position, results of operations, or cash flows.

California — On May 4, 2010, in Southern California Edison Company v. FERC, the U.S. Court of Appeals for the D.C. Circuit vacated the FERC's acceptance of station power rules for the California Independent System Operator, or CAISO, market, and remanded the case for further proceedings at the FERC. On August 30, 2010, the FERC issued an Order on Remand effectively disclaiming jurisdiction over how the states impose retail station power charges. Due to reservation-of-rights language in the California utilities' state-jurisdictional station power tariffs, the FERC's ruling arguably requires California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO's station period program (February 1, 2009, for the Company's Encina and El Segundo facilities; March 1, 2009, for the Company's Long Beach facility). On February 28, 2011, the FERC issued an order denying rehearing. The Company, together with other generators, filed an appeal in the D.C. Circuit. The oral argument was held on September 19, 2012 and the decision is pending.

On November 18, 2011, Southern California Edison Company filed with the CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively, which the Company and other generators have challenged. On August 13, 2012, the CPUC Energy Division issued a draft resolution in which it rejected the Company's arguments and approved Southern California Edison's proposed station power charges, including retroactive implementation. The CPUC Commissioners were scheduled to vote on the draft resolution on October 15, 2012. The draft resolution was withdrawn from the calendar and has not yet been rescheduled. The Company believes it has established an appropriate reserve.

Retail (Replacement Reserve) — On November 14, 2006, Constellation Energy Commodities Group, or Constellation, filed a complaint with the PUCT alleging that ERCOT misapplied the Replacement Reserve Settlement, or RPRS, Formula contained in the ERCOT protocols from April 10, 2006, through September 27, 2006. Specifically, Constellation disputed approximately $4 million in under-scheduling charges for capacity insufficiency asserting that ERCOT applied the wrong protocol. Retail Electric Providers, or REPS, other market participants, ERCOT, and PUCT staff opposed Constellation's complaint. On January 25, 2008, the PUCT entered an order finding that ERCOT correctly settled the capacity insufficiency charges for the disputed dates in accordance with ERCOT protocols and denied Constellation's complaint. On April 9, 2008, Constellation appealed the PUCT order to the Civil District Court of Travis County, Texas and on June 19, 2009, the court issued a judgment reversing the PUCT order, finding that the ERCOT protocols were in irreconcilable conflict with each other. Under the PUCT ordered formula, Qualified Scheduling Entities, or QSEs, who under-scheduled capacity within any of ERCOT's four congestion zones were assessed under-scheduling charges which defrayed the costs incurred by ERCOT for RPRS that would otherwise be spread among all load-serving QSEs. Under the Court's decision, all RPRS costs would be assigned to all load-serving QSEs based upon their load ratio share without assessing any separate charge to those QSEs who under-scheduled capacity. If under-scheduling charges for capacity insufficient QSEs were not used to defray RPRS costs, REPS's share of the total RPRS costs allocated to QSEs would increase. On July 20, 2009, REPS filed an appeal to the Third Court of Appeals in Travis County, Texas, thereby staying the effect of the trial court's decision. On October 6, 2010, the parties argued the appeal before the Court of Appeals for the Third District in Austin, Texas. On September 28, 2011, the Court of Appeals reversed the trial court decision, reinstating the PUCT's order, consistent with REPS's position. On January 13, 2012, Constellation filed a Petition for Review in the Supreme Court of Texas asking the Court to grant review of and reverse the Court of Appeals decision. The Texas Supreme Court requested that briefs on the merits be filed before deciding whether to hear the Petition for Review. Briefing is currently underway and the Company filed its brief on October 15, 2012.

Retail (Midwest ISO SECA) — Green Mountain Energy previously provided competitive retail energy supply in the Midwest ISO region during the relevant period of January 1, 2002, to December 31, 2005. By order dated November 18, 2004, the FERC eliminated certain regional through-and-out transmission rates charged by transmission owners in the regional electric grids operated by the Midwest Independent Transmission System Operator, Inc., or MISO, and PJM Interconnection, L.L.C., or PJM. In order to temporarily compensate the transmission owners for revenue lost as a result of the elimination of the through-and-out transmission rates, the FERC also ordered MISO, PJM and their respective transmission owners to provide for the recovery of certain Seams Elimination Charge/Cost Adjustments/Assignments, or SECA, charges effective December 1, 2004, through March 31, 2006, based on usage during 2002 and 2003. The tariff amendments filed by MISO and the MISO transmission owners allocated certain SECA charges to various zones and sub-zones within MISO, including a sub-zone called the Green Mountain Energy Company Sub-zone. Over the last several years, there has been extensive litigation before the FERC relating to these charges, seeking, among other things, to recover monies from Green Mountain Energy, and before the federal appellate courts. Green Mountain Energy has not paid any asserted SECA charges.

On May 21, 2010, the FERC issued two orders. In its Order on Rehearing, the FERC denied all requests for rehearing of its past orders directing and accepting the SECA compliance filings of MISO, PJM, and the transmission owners. In its Order on Initial Decision, the FERC: (1) affirmed an order by the Administrative Law Judge granting Green Mountain Energy partial summary judgment and holding Green Mountain Energy not liable for SECA charges for January - March 2006; and (2) reversed an August 2006 determination by the Administrative Law Judge that Green Mountain Energy could be held directly liable for some amount of SECA charges. The Order on Initial Decision also directed that the two Regional Transmission Organizations, or RTOs, and their respective transmission owners submit further compliance filings, which were filed on August 19, 2010. The FERC has not yet ruled on those compliance filings.

With regard to the SECA charges that had been invoiced to Green Mountain Energy, the FERC determined that most of those charges, approximately $22 million plus interest, were owed not by Green Mountain Energy but rather by BP Energy — one of Green Mountain Energy's suppliers during the period at issue. On August 19, 2010, the transmission owners and MISO made compliance filings in accordance with the FERC's Orders allocating SECA charges to a BP Energy Sub-zone, and making no allocation to a Green Mountain Energy sub-zone. BP Energy has not asserted any contractual claims against Green Mountain Energy. The Company believes it has established an appropriate reserve.

On September 30, 2011, the FERC issued orders denying BP Energy's request for rehearing of the May 2010 Order on Rehearing, denying all requests for rehearing of the Order on Initial Decision, and again determined that SECA charges were not owed by Green Mountain Energy. Numerous parties have sought judicial review of the FERC's Order on Initial Decision, and BP Energy has sought judicial review of the May 2010 Order on Rehearing. These appeals have been consolidated with previous appeals of orders relating to SECA before the U.S. Court of Appeals for the DC Circuit. Green Mountain Energy has been granted intervenor status in the consolidated appeals.

On May 10, 2012, the Court issued an order setting out a briefing schedule which provided for the submittal of petitioners' briefs on July 17, 2012. On July 5, 2012, BP Energy and three PJM transmission owners filed a motion asking the Court to vacate the briefing schedule. The movants stated that respondent FERC and all other petitioners either supported or did not oppose the motion. The movants further stated that they had reached a settlement resolving all SECA claims involving BP Energy, were filing the settlement agreement with the FERC that day, and desired a vacation of the briefing schedule to enable the FERC to act on the proposed settlement. The movants did in fact file the settlement agreement at the FERC that day. The agreement provided for BP Energy to pay a total of approximately $24 million to the three transmission owners signing the agreement, with another $1 million offered to the remaining PJM transmission owners, should they choose to join the settlement. The FERC approved the settlement agreement by order dated August 22, 2012 and the deadline for seeking rehearing of that order passed without any parties seeking rehearing. The settlement became effective on September 21, 2012, triggering a ten-day period during which other PJM transmission owners could choose to opt-in to the settlement by filing a notification of their choice with the FERC. All have done so.

In response to a July 10, 2012 D.C. Circuit order granting the July 5, 2012 motion to vacate the briefing schedule and directing the remaining parties to submit a motion to govern further proceedings by September 17, 2012, the parties filed a joint motion on that date requesting the continued abeyance of the consolidated proceedings. The motion stated that BP Energy would withdraw its petitions for review once the BP Energy settlement agreement became effective and noted that some of the remaining petitioners were involved in on-going settlement discussions. On September 24, 2012, the D.C. Circuit granted the motion and directed the parties to file motions to govern future proceedings by November 19, 2012. BP Energy filed a motion to withdraw its two petitions for review on September 25, 2012, which motion was granted by court orders dated September 27, 2012.

Note 16 — Environmental Matters

NRG is subject to a wide range of environmental regulations across a broad number of jurisdictions in the development, ownership, construction and operation of domestic and international projects. These laws and regulations generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental regulations have become increasingly stringent and NRG expects this trend to continue. The electric generation industry is likely to face new requirements to address various emissions, including greenhouse gases, as well as combustion byproducts and water use. In general, future laws and regulations are expected to require the addition of emissions controls or other environmental quality equipment or the imposition of certain restrictions on the operations of the Company's facilities, which could have a material effect on the Company's operations or competitive position.

Environmental Capital Expenditures

Based on current rules, technology and plans as well as preliminary plans based on proposed rules, NRG has estimated that environmental capital expenditures from 2012 through 2016 to meet NRG's regulatory environmental commitments will be approximately $440 million. These costs are primarily associated with mercury controls to satisfy the Mercury and Air Toxics Standards, or MATS, on the Company's Big Cajun II, W.A. Parish and Limestone facilities and a number of intake modification projects across the fleet under state or proposed federal 316(b) rules. The change from our previous estimate of $553 million reflects a decrease in costs related to changes in technology related to MATS compliance, completing projects below budget, and shifts in compliance schedules based on regulatory changes.

NRG continues to explore cost effective compliance alternatives to reduce costs. While this estimate reflects anticipated schedules and controls related to the proposed 316(b) Rule (the EPA pushed back the final 316(b) rule from July 2012 to July 2013), the full impact on the scope and timing of environmental retrofits from any new or revised regulations cannot be determined until these rules are final and any legal challenges are reviewed. However, NRG believes it is positioned to meet more stringent environmental regulations through its planned capital expenditures, existing controls, and increasing generation from renewable resources.

NRG's current contracts with the Company's rural electric cooperative customers in the South Central region allow for recovery of a portion of the region's environmental capital costs incurred as the result of complying with any change in environmental law. Cost recoveries begin once the environmental equipment becomes operational and include a capital return. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

Northeast Region

In January 2006, NRG's Indian River Operations, Inc. received a letter of informal notification from Delaware Department of Natural Resources and Environmental Control, or DNREC, stating that it may be a potentially responsible party with respect to Burton Island Old Ash Landfill, a historic captive landfill located at the Indian River facility. On October 1, 2007, NRG signed an agreement with DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, DNREC issued findings that no further action is required in relation to surface water and that a previously planned shoreline stabilization project would satisfactorily address shoreline erosion. The landfill itself will require a further Remedial Investigation and Feasibility Study to determine the type and scope of any additional work required. Until the Remedial Investigation and Feasibility Study is approved, the Company is unable to predict the impact of any required remediation. On May 29, 2008, DNREC requested that NRG's Indian River Operations, Inc. participate in the development and performance of a Natural Resource Damage Assessment, or NRDA, at the Burton Island Old Ash Landfill. NRG is currently working with DNREC and other trustees to close out the assessment phase.

South Central Region

On September 7, 2012, LaGen received a Consolidated Compliance Order & Notice of Potential Penalty, or CCO&NPP, from the LDEQ. The CCO&NPP alleges that there were opacity exceedance events from the three electric generating units at the Big Cajun II power plant facility on certain dates and times during the years 2007-2012. On October 8, 2012, LaGen filed a Request for Administrative Adjudicatory Hearing in response to the CCO&NPP. Pending this hearing, LaGen is cooperating with the LDEQ and responding in good faith to the CCO&NPP. NRG is unable to predict the outcome of this matter at this preliminary stage of the proceeding.

On February 11, 2009, the U.S. DOJ acting at the request of the U.S. EPA commenced a lawsuit against LaGen in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. This is the same matter for which NOVs were issued to LaGen on February 15, 2005, and on December 8, 2006. On October 17, 2012, prior to the start of liability-phase trial which had been temporarily adjourned, the parties notified the court that they had reached an agreement on terms of a settlement which requires final approval by the U.S. DOJ. The terms of the agreement generally require LaGen to install certain emission control equipment technologies, which are not expected to have an adverse impact on NRG's planned environmental capital expenditures. Further discussion on this matter can be found in Note 14, Commitments and Contingencies, of this Form 10-Q.

Note 17 — Condensed Consolidating Financial Information

As of September 30, 2012, the Company had outstanding $6.2 billion of Senior Notes due from 2017 - 2023, as shown in Note 8, Debt and Capital Leases. These Senior Notes are guaranteed by certain of NRG's current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries. The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of September 30, 2012:

Arthur Kill Power LLC	NEO Freehold-Gen LLC	NRG Power Marketing LLC
Astoria Gas Turbine Power LLC	NEO Power Services Inc.	NRG Renter's Protection LLC
Cabrillo Power I LLC	New Genco GP, LLC	NRG Retail LLC
Cabrillo Power II LLC	Norwalk Power LLC	NRG Rockford Acquisition LLC
Carbon Management Solutions LLC	NRG Affiliate Services Inc.	NRG Saguaro Operations Inc.
Clean Edge Energy LLC	NRG Artesian Energy LLC	NRG Security LLC
Conemaugh Power LLC	NRG Arthur Kill Operations Inc.	NRG Services Corporation
Connecticut Jet Power LLC	NRG Astoria Gas Turbine Operations Inc.	NRG SimplySmart Solutions LLC
Cottonwood Development LLC	NRG Bayou Cove LLC	NRG South Central Affiliate Services Inc.
Cottonwood Energy Company LP	NRG Cabrillo Power Operations Inc.	NRG South Central Generating LLC
Cottonwood Generating Partners I LLC	NRG California Peaker Operations LLC	NRG South Central Operations Inc.
Cottonwood Generating Partners II LLC	NRG Cedar Bayou Development Company, LLC	NRG South Texas LP
Cottonwood Generating Partners III LLC	NRG Connecticut Affiliate Services Inc.	NRG Texas C&I Supply LLC
Cottonwood Technology Partners LP	NRG Construction LLC	NRG Texas Holding Inc.
Devon Power LLC	NRG Development Company Inc.	NRG Texas LLC
Dunkirk Power LLC	NRG Devon Operations Inc.	NRG Texas Power LLC
Eastern Sierra Energy Company LLC	NRG Dispatch Services LLC	NRG Unemployment Protection LLC
El Segundo Power, LLC	NRG Dunkirk Operations Inc.	NRG Warranty Services LLC
El Segundo Power II LLC	NRG El Segundo Operations Inc.	NRG West Coast LLC
Elbow Creek Wind Project LLC	NRG Energy Labor Services LLC	NRG Western Affiliate Services Inc.
Energy Plus Holdings LLC	NRG Energy Services Group LLC	O'Brien Cogeneration, Inc. II
Energy Plus Natural Gas LLC	NRG Energy Services LLC	ONSITE Energy, Inc.
Energy Protection Insurance Company	NRG Generation Holdings, Inc.	Oswego Harbor Power LLC
Everything Energy LLC	NRG Home & Business Solutions LLC	RE Retail Receivables, LLC
GCP Funding Company, LLC	NRG Home Solutions Product LLC	Reliant Energy Northeast LLC
Green Mountain Energy Company	NRG Huntley Operations Inc.	Reliant Energy Power Supply, LLC
Green Mountain Energy Company	NRG Identity Protect LLC	Reliant Energy Retail Holdings, LLC
(NY Com) LLC	NRG Ilion Limited Partnership	Reliant Energy Retail Services, LLC
Green Mountain Energy Company	NRG Ilion LP LLC	RERH Holdings, LLC
(NY Res) LLC	NRG International LLC	Saguaro Power LLC
Huntley Power LLC	NRG Maintenance Services LLC	Somerset Operations Inc.
Independence Energy Alliance LLC	NRG Mextrans Inc.	Somerset Power LLC
Independence Energy Group LLC	NRG MidAtlantic Affiliate Services Inc.	Texas Genco Financing Corp.

Independence Energy Natural Gas LLC	NRG Middletown Operations Inc.	Texas Genco GP, LLC
Indian River Operations Inc.	NRG Montville Operations Inc.	Texas Genco Holdings, Inc.
Indian River Power LLC	NRG New Jersey Energy Sales LLC	Texas Genco LP, LLC
Keystone Power LLC	NRG New Roads Holdings LLC	Texas Genco Operating Services, LLC
Langford Wind Power, LLC	NRG North Central Operations Inc.	Texas Genco Services, LP
Louisiana Generating LLC	NRG Northeast Affiliate Services Inc.	US Retailers LLC
Meriden Gas Turbines LLC	NRG Norwalk Harbor Operations Inc.	Vienna Operations Inc.
Middletown Power LLC	NRG Operating Services, Inc.	Vienna Power LLC
Montville Power LLC	NRG Oswego Harbor Power Operations Inc.	WCP (Generation) Holdings LLC
NEO Corporation	NRG PacGen Inc.	West Coast Power LLC

NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company's ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG's ability to receive funds from its subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under the Company's Peaker financing agreements, there are no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to NRG. In addition, there may be restrictions for certain non-guarantor subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities.

In this presentation, NRG Energy, Inc. consists of parent company operations. Guarantor subsidiaries and non-guarantor subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended September 30, 2012
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
	(In millions)				
Operating Revenues					
Total operating revenues	$2,237	$ 120	$—	$ (26)	$2,331
Operating Costs and Expenses					
Cost of operations	1,701	47	1	(23)	1,726
Depreciation and amortization	217	20	2	—	239
Selling, general and administrative	168	14	74	(3)	253
Acquisition-related transaction and integration costs	—	—	18	—	18
Development costs	—	—	9	—	9
Total operating costs and expenses	2,086	81	104	(26)	2,245
Operating Income/(Loss)	151	39	(104)	—	86
Other (Expense)/Income					
Equity in (losses)/earnings of consolidated subsidiaries	(10)	1	121	(112)	—
Equity in earnings of unconsolidated affiliates	4	—	—	—	4
Impairment charge on investment	(1)	—	—	—	(1)
Other income, net	1	2	7	—	10
Loss on debt extinguishment	—	—	(41)	—	(41)
Interest expense	(5)	(21)	(137)	—	(163)
Total other expense	(11)	(18)	(50)	(112)	(191)
Income Before Income Taxes	140	21	(154)	(112)	(105)
Income tax expense(benefit)	67	(27)	(153)	—	(113)
Net Income/(Loss)	73	48	(1)	(112)	8
Less: Net income attributable to noncontrolling interest	—	9	—	—	9
Net Income/(Loss) attributable to NRG Energy, Inc.	$73	$ 39	$(1)	$ (112)	$(1)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Nine Months Ended September 30, 2012
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 6,058	$ 353	$—	$ (52)	$ 6,359
Operating Costs and Expenses					
Cost of operations	4,478	178	7	(45)	4,618
Depreciation and amortization	647	48	8	—	703
Selling, general and administrative	421	36	231	(7)	681
Acquisition-related transaction and integration costs	—	—	18	—	18
Development costs	—	—	26	—	26
Total operating costs and expenses	5,546	262	290	(52)	6,046
Operating Income/(Loss)	512	91	(290)	—	313
Other (Expense)/Income					
Equity in earnings/(losses) of consolidated subsidiaries	6	(11)	463	(458)	—
Equity in earnings of unconsolidated affiliates	6	20	—	—	26
Impairment charge on investment	(2)	—	—	—	(2)
Other income, net	2	4	8	—	14
Loss on debt extinguishment	—	—	(41)	—	(41)
Interest expense	(21)	(60)	(414)	—	(495)
Total other (expense)/income	(9)	(47)	16	(458)	(498)
Income/(Loss) Before Income Taxes	503	44	(274)	(458)	(185)
Income tax expense/(benefit)	193	(122)	(317)	—	(246)
Net Income	310	166	43	(458)	61
Less: Net income attributable to noncontrolling interest	—	18	—	—	18
Net Income attributable to NRG Energy, Inc.	$ 310	$ 148	$43	$ (458)	$43

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Three Months Ended September 30, 2012
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income/(Loss)	$73	$48	$(1)	$(112)	$8
Other comprehensive loss, net of tax					
Unrealized loss on derivatives, net	(43)	(14)	(54)	68	(43)
Foreign currency translation adjustments, net	—	—	1	—	1
Reclassification adjustment for translation gain realized upon sale of Schkopau, net	—	(11)	—	—	(11)
Available-for-sale securities, net	—	—	2	—	2
Other comprehensive loss	(43)	(25)	(51)	68	(51)
Comprehensive income/(loss)	30	23	(52)	(44)	(43)
Less: Comprehensive income attributable to noncontrolling interest	—	9	—	—	9
Comprehensive income/(loss) attributable to NRG Energy, Inc.	30	14	(52)	(44)	(52)
Dividends for preferred shares	—	—	2	—	2
Comprehensive income/(loss) available for common stockholders	$30	$14	$(54)	$(44)	$(54)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Nine Months Ended September 30, 2012
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income	$310	$166	$43	$(458)	$61
Other comprehensive loss, net of tax					
Unrealized loss on derivatives, net	(122)	(33)	(145)	168	(132)
Foreign currency translation adjustments, net	—	(2)	1	—	(1)
Reclassification adjustment for translation gain realized upon sale of Schkopau, net	—	(11)	—	—	(11)
Available-for-sale securities, net	—	—	2	—	2
Other comprehensive loss	(122)	(46)	(142)	168	(142)
Comprehensive income/(loss)	188	120	(99)	(290)	(81)
Less: Comprehensive income attributable to noncontrolling interest	—	18	—	—	18
Comprehensive income/(loss) attributable to NRG Energy, Inc.	188	102	(99)	(290)	(99)
Dividends for preferred shares	—	—	7	—	7
Comprehensive income/(loss) available for common stockholders	$188	$102	$(106)	$(290)	$(106)

(a) All significant intercompany transactions have been eliminated in consolidation.

41

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
September 30, 2012
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
ASSETS					
Current Assets					
Cash and cash equivalents	$11	$223	$1,376	$—	$1,610
Funds deposited by counterparties	76	—	—	—	76
Restricted cash	9	212	16	—	237
Accounts receivable, net	1,027	48	—	—	1,075
Inventory	381	12	—	—	393
Derivative instruments	2,677	—	—	—	2,677
Cash collateral paid in support of energy risk management activities	98	—	—	—	98
Prepayments and other current assets	2,672	12	(2,467)	—	217
Total current assets	6,951	507	(1,075)	—	6,383
Net property, plant and equipment	10,026	5,757	102	(19)	15,866
Other Assets					
Investment in subsidiaries	80	(48)	16,518	(16,550)	—
Equity investments in affiliates	34	603	12	—	649
Notes receivable – affiliate and capital leases, less current portion	3	74	727	(726)	78
Goodwill	1,886	—	—	—	1,886
Intangible assets, net	1,116	80	30	(38)	1,188
Nuclear decommissioning trust fund	469	—	—	—	469
Derivative instruments	309	—	—	—	309
Other non-current assets	70	113	209	—	392
Total other assets	3,967	822	17,496	(17,314)	4,971
Total Assets	$20,944	$7,086	$16,523	$(17,333)	$27,220
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$—	$88	$286	$—	$374
Accounts payable	(20)	328	938	—	1,246
Derivative instruments	2,436	17	9	—	2,462
Deferred income taxes	262	(56)	(191)	—	15
Cash collateral received in support of energy risk management activities	76	—	—	—	76
Accrued expenses and other current liabilities	349	37	218	—	604
Total current liabilities	3,103	414	1,260	—	4,777
Other Liabilities					
Long-term debt and capital leases	273	3,933	7,488	(726)	10,968

Nuclear decommissioning reserve	349	—	—	—	349
Nuclear decommissioning trust liability	277	—	—	—	277
Deferred income taxes	1,352	217	(477)	—	1,092
Derivative instruments	451	110	—	—	561
Out-of-market commodity contracts	186	6	—	(31)	161
Other non-current liabilities	567	216	113	—	896
Total non-current liabilities	3,455	4,482	7,124	(757)	14,304
Total liabilities	6,558	4,896	8,384	(757)	19,081
3.625% convertible perpetual preferred stock	—	—	249	—	249
Stockholders' Equity	14,386	2,190	7,890	(16,576)	7,890
Total Liabilities and Stockholders' Equity	$ 20,944	$ 7,086	$ 16,523	$ (17,333)	$ 27,220

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Cash Flows from Operating Activities					
Net income	$310	$ 166	$43	$ (458)	$ 61
Adjustments to reconcile net income to net cash provided/(used) by operating activities:					
Distributions and equity in (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	(6)	19	(285)	280	8
Depreciation and amortization	647	48	8	—	703
Provision for bad debts	40	—	—	—	40
Amortization of nuclear fuel	29	—	—	—	29
Amortization of financing costs and debt discount/premiums	—	8	17	—	25
Loss on debt extinguishment	—	—	8	—	8
Amortization of intangibles and out-of-market commodity contracts	107	1	—	—	108
Amortization of unearned equity compensation	—	—	27	—	27
Changes in deferred income taxes and liability for uncertain tax benefits	193	(122)	(332)	—	(261)
Changes in nuclear decommissioning trust liability	25	—	—	—	25
Changes in derivative instruments	360	—	—	—	360
Changes in collateral deposits supporting energy risk management activities	213	—	—	—	213
Cash provided/(used) by changes in other working capital	24	57	(369)	—	(288)
Net Cash Provided/(Used) by Operating Activities	1,942	177	(883)	(178)	1,058
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(1,686)	416	—	1,270	—
Acquisition of businesses, net of cash acquired	—	(17)	(23)	—	(40)
Capital expenditures	(183)	(2,241)	(50)	—	(2,474)
Increase in restricted cash, net	(2)	(94)	—	—	(96)
Decrease in restricted cash - U.S. DOE projects	—	113	38	—	151
Increase in notes receivable	—	(20)	(2)	—	(22)
Purchases of emissions allowances	(8)	—	—	—	(8)
Proceeds from sale of emissions allowances	8	—	—	—	8
Investments in nuclear decommissioning trust fund securities	(341)	—	—	—	(341)
Proceeds from sales of nuclear decommissioning trust fund securities	316	—	—	—	316

Proceeds from renewable energy grants	3	46	—	—	49
Proceeds from sale of assets	133	—	4	—	137
Other	13	(8)	(14)	—	(9)
Net Cash Used by Investing Activities	(1,747)	(1,805)	(47)	1,270	(2,329)
Cash Flows from Financing Activities					
Proceeds from intercompany loans	—	—	1,270	(1,270)	—
Payment of dividends to common and preferred stockholders	—	—	(28)	—	(28)
Payments of intercompany dividends	(172)	(6)	—	178	—
Net payments for settlement of acquired derivatives that include financing elements	(65)	—	—	—	(65)
Sale proceeds and other contributions from noncontrolling interest in subsidiaries	—	316	—	—	316
Proceeds from issuance of long-term debt	9	1,526	1,006	—	2,541
Payment of debt issuance and hedging costs	—	(16)	(14)	—	(30)
Payments for short and long-term debt	—	(51)	(904)	—	(955)
Net Cash (Used)/Provided by Financing Activities	(228)	1,769	1,330	(1,092)	1,779
Effect of exchange rate changes on cash and cash equivalents	—	(3)	—	—	(3)
Net (Decrease)/Increase in Cash and Cash Equivalents	(33)	138	400	—	505
Cash and Cash Equivalents at Beginning of Period	44	85	976	—	1,105
Cash and Cash Equivalents at End of Period	$11	$ 223	$1,376	$ —	$ 1,610

(a) All significant intercompany transactions have been eliminated in consolidation.

43

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended September 30, 2011
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Operating Revenues					
Total operating revenues	$2,581	$97	$—	$(4)	$2,674
Operating Costs and Expenses					
Cost of operations	1,993	63	(1)	(2)	2,053
Depreciation and amortization	224	10	4	—	238
Impairment charge on emission allowances	160	—	—	—	160
Selling, general and administrative	102	8	61	(2)	169
Development costs	—	—	11	—	11
Total operating costs and expenses	2,479	81	75	(4)	2,631
Operating Income/(Loss)	102	16	(75)	—	43
Other (Expense)/Income					
Equity in earnings of consolidated subsidiaries	6	4	88	(98)	—
Equity in earnings of unconsolidated affiliates	2	14	—	—	16
Impairment charge on investment	(3)	—	—	—	(3)
Other income, net	3	1	1	—	5
Loss on debt extinguishment	—	—	(32)	—	(32)
Interest expense	(20)	(13)	(131)	—	(164)
Total other (expense)/income	(12)	6	(74)	(98)	(178)
Income/(Loss) Before Income Taxes	90	22	(149)	(98)	(135)
Income tax expense/(benefit)	11	3	(94)	—	(80)
Net Income/(Loss) attributable to NRG Energy, Inc.	$79	$19	$(55)	$(98)	$(55)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Nine Months Ended September 30, 2011
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$6,670	$291	$—	$ (14)	$6,947
Operating Costs and Expenses					
Cost of operations	4,791	194	5	(5)	4,985
Depreciation and amortization	626	28	11	—	665
Impairment charge on emissions allowances	160	—	—	—	160
Selling, general and administrative	276	20	185	(2)	479
Development costs	—	(1)	33	—	32
Total operating costs and expenses	5,853	241	234	(7)	6,321
Operating Income/(Loss)	817	50	(234)	(7)	626
Other Expense					
Equity in earnings/(losses) of consolidated subsidiaries	21	(5)	185	(201)	—
Equity in earnings of unconsolidated affiliates	8	18	—	—	26
Impairment charge on investment	(495)	—	—	—	(495)
Other income, net	3	6	4	—	13
Loss on debt extinguishment	—	—	(175)	—	(175)
Interest expense	(46)	(40)	(418)	—	(504)
Total other expense	(509)	(21)	(404)	(201)	(1,135)
Income/(Loss) Before Income Taxes	308	29	(638)	(208)	(509)
Income tax expense/(benefit)	123	6	(944)	—	(815)
Net Income attributable to NRG Energy, Inc.	$185	$23	$306	$ (208)	$306

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE LOSS
For the Three Months Ended September 30, 2011
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
	(In millions)				
Net Income/(Loss)	$79	$ 19	$(55)	$ (98)	$(55)
Other comprehensive loss, net of tax					
Unrealized loss on derivatives, net	(94)	(11)	(100)	129	(76)
Foreign currency translation adjustments, net	—	(24)	(3)	—	(27)
Available-for-sale securities, net	—	—	(1)	—	(1)
Other comprehensive loss	(94)	(35)	(104)	129	(104)
Comprehensive loss attributable to NRG Energy, Inc.	(15)	(16)	(159)	31	(159)
Dividends for preferred shares	—	—	2	—	2
Comprehensive loss available for common stockholders	$(15)	$ (16)	$(161)	$ 31	$(161)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE (LOSS)/INCOME
For the Nine Months Ended September 30, 2011
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income	$185	$23	$306	$(208)	$306
Other comprehensive loss, net of tax					
Unrealized loss on derivatives, net	(232)	(13)	(228)	248	(225)
Foreign currency translation adjustments, net	—	(4)	(1)	—	(5)
Available-for-sale securities, net	—	—	(2)	—	(2)
Defined benefit plan	1	—	—	—	1
Other comprehensive loss	(231)	(17)	(231)	248	(231)
Comprehensive (loss)/income attributable to NRG Energy, Inc.	(46)	6	75	40	75
Dividends for preferred shares	—	—	7	—	7
Comprehensive (loss)/income available for common stockholders	$(46)	$6	$68	$40	$68

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
ASSETS					
Current Assets					
Cash and cash equivalents	$44	$ 85	$976	$ —	$ 1,105
Funds deposited by counterparties	258	—	—	—	258
Restricted cash	8	231	53	—	292
Accounts receivable-trade, net	789	45	—	—	834
Inventory	300	8	—	—	308
Derivative instruments	4,222	—	—	(6)	4,216
Cash collateral paid in support of energy risk management activities	311	—	—	—	311
Prepayments and other current assets	1,229	28	(983)	(1)	273
Total current assets	7,161	397	46	(7)	7,597
Net Property, Plant and Equipment	10,456	3,116	67	(18)	13,621
Other Assets					
Investment in subsidiaries	225	491	16,169	(16,885)	—
Equity investments in affiliates	33	607	—	—	640
Capital leases and notes receivable, less current portion	1	341	172	(172)	342
Goodwill	1,886	—	—	—	1,886
Intangible assets, net	1,340	84	33	(38)	1,419
Nuclear decommissioning trust fund	424	—	—	—	424
Derivative instruments	450	—	—	—	450
Other non-current assets	55	72	209	—	336
Total other assets	4,414	1,595	16,583	(17,095)	5,497
Total Assets	$22,031	$ 5,108	$16,696	$ (17,120)	$ 26,715
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$—	$ 72	$15	$ —	$ 87
Accounts payable	(407)	122	1,093	—	808
Derivative instruments	3,712	23	22	(6)	3,751
Deferred income taxes	534	(51)	(356)	—	127
Cash collateral received in support of energy risk management activities	258	—	—	—	258
Accrued expenses and other current liabilities	371	23	247	(1)	640
Total current liabilities	4,468	189	1,021	(7)	5,671
Other Liabilities					
Long-term debt and capital leases	264	1,999	7,654	(172)	9,745
Nuclear decommissioning reserve	335	—	—	—	335

Nuclear decommissioning trust liability	254	—	—	—	254
Deferred income taxes	950	273	166	—	1,389
Derivative instruments	394	66	4	—	464
Out-of-market commodity contracts	208	6	—	(31)	183
Other non-current liabilities	544	96	116	—	756
Total non-current liabilities	2,949	2,440	7,940	(203)	13,126
Total liabilities	7,417	2,629	8,961	(210)	18,797
3.625% Preferred Stock	—	—	249	—	249
Stockholders’ Equity	14,614	2,479	7,486	(16,910)	7,669
Total Liabilities and Stockholders’ Equity	$ 22,031	$ 5,108	$ 16,696	$ (17,120)	$ 26,715

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2011
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Cash Flows from Operating Activities					
Net income	$ 185	$ 23	$ 306	$ (208)	$ 306
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	(10)	2	1,184	(1,168)	8
Depreciation and amortization	626	28	11	—	665
Provision for bad debts	41	—	—	—	41
Amortization of nuclear fuel	31	—	—	—	31
Amortization of financing costs and debt discount/premiums	—	5	20	—	25
Loss on debt extinguishment	—	—	58	—	58
Amortization of intangibles and out-of market commodity contracts	118	—	—	—	118
Amortization of unearned equity compensation	—	—	14	—	14
Changes in deferred income taxes and liability for uncertain tax benefits	123	6	(958)	—	(829)
Changes in nuclear decommissioning trust liability	20	—	—	—	20
Changes in derivative instruments	(199)	1	(3)	—	(201)
Changes in collateral deposits supporting energy risk management activities	5	2	—	—	7
Impairment charge on investment	481	—	—	—	481
Impairment charge on emission allowance	160	—	—	—	160
Cash (used)/provided by changes in other working capital	(1,182)	211	728	7	(236)
Net Cash Provided by Operating Activities	399	278	1,360	(1,369)	668
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(191)	—	(486)	677	—
Acquisition of business, net of cash acquired	—	(91)	(261)	—	(352)
Capital expenditures	(295)	(1,027)	(33)	—	(1,355)
Increase in restricted cash, net	(54)	(38)	—	—	(92)
Increase in restricted cash - U.S. DOE projects	—	(254)	(62)	—	(316)
Decrease in notes receivable	—	27	—	—	27
Purchase of emission allowances	(27)	—	—	—	(27)
Proceeds from sale of emission allowances	6	—	—	—	6
Investments in nuclear decommissioning trust fund securities	(314)	—	—	—	(314)
	294	—	—	—	294

Proceeds from sales of nuclear decommissioning trust fund securities					
Proceeds from sale of assets	14	—	—	—	14
Investments in unconsolidated affiliates	(1)	(16)	—	—	(17)
Other	(11)	(8)	(10)	—	(29)
Net Cash Used by Investing Activities	(579)	(1,407)	(852)	677	(2,161)
Cash Flows from Financing Activities					
Proceeds from intercompany loans	38	448	191	(677)	—
Payment of dividends to preferred stockholders	—	—	(7)	—	(7)
Payment of intercompany dividends	(65)	(1,304)	—	1,369	—
Payment for treasury stock	—	—	(378)	—	(378)
Net payment for settlement of acquired derivatives that include financing elements	(61)	—	—	—	(61)
Proceeds from issuance of long-term debt	116	798	4,796	—	5,710
Decrease in restricted cash supporting funded letter of credit	—	1,300	—	—	1,300
Payment for settlement of funded letter of credit	—		(1,300)	—	(1,300)
Proceeds from issuance of common stock	—	—	2	—	2
Payment of debt issuance and hedging costs	—	(41)	(108)	—	(149)
Payments for short and long-term debt	—	(77)	(5,373)	—	(5,450)
Net Cash Provided/(Used) by Financing Activities	28	1,124	(2,177)	692	(333)
Effect of exchange rate changes on cash and cash equivalents	—	2	—	—	2
Net Decrease in Cash and Cash Equivalents	(152)	(3)	(1,669)	—	(1,824)
Cash and Cash Equivalents at Beginning of Period	168	111	2,672	—	2,951
Cash and Cash Equivalents at End of Period	$16	$ 108	$1,003	$ —	$ 1,127

(a) All significant intercompany transactions have been eliminated in consolidation.

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

As you read this discussion and analysis, refer to NRG's Condensed Consolidated Statements of Operations to this Form 10-Q, which present the results of operations for the three and nine months ended September 30, 2012, and 2011. Also refer to NRG's Annual Report on Form 10-K for the year ended December 31, 2011, or 2011 Form 10-K, which includes detailed discussions of various items impacting the Company's business, results of operations and financial condition, including: Introduction and Overview section which provides a description of NRG's business segments; Strategy section; Business Environment section, including how regulation, weather, and other factors affect NRG's business; and Critical Accounting Policies and Estimates section. As described in Note 12, Segment Reporting, NRG updated its segment structure to reflect how management currently makes its financial decisions and allocates resources, based on the Retail businesses, conventional power generation, alternative energy businesses and corporate activities.

The discussion and analysis below has been organized as follows:

- Executive summary, including introduction and overview, business strategy, and changes to the business environment during the period including environmental and regulatory matters;
- Results of operations;
- Financial condition, addressing liquidity position, sources and uses of liquidity, capital resources and requirements, commitments, and off-balance sheet arrangements; and
- Known trends that may affect NRG's results of operations and financial condition in the future.

Executive Summary

Introduction and Overview

NRG Energy, Inc., or NRG or the Company, is an integrated wholesale power generation and retail electricity company that aspires to be a leader in the way the industry and consumers think about, use, produce, and deliver energy and energy services in major competitive power markets in the United States. First, NRG is a wholesale power generator engaged in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services. Second, NRG is a retail electricity company engaged in the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through its Retail businesses. Finally, NRG is focused on the deployment and commercialization of potential disruptive clean energy technologies, like electric vehicles, Distributed Solar and smart meter technology, which have the potential to change the nature of the power supply industry.

NRG's Business Strategy

NRG's business strategy is intended to maximize stockholder value through the production and sale of safe, reliable and affordable power to its customers in the markets served by the Company, while aggressively positioning the Company to meet the market's increasing demand for sustainable and low carbon energy solutions. This strategy is designed to enhance the Company's core business of competitive power generation and mitigate the risk of declining power prices. The Company expects to become a leading provider of sustainable energy solutions that promotes national energy security, while utilizing the Company's Retail businesses to complement and advance both initiatives.

The Company's core business is focused on: (i) excellence in safety and operating performance of its existing assets; (ii) serving the energy needs of end-use residential, commercial and industrial customers in the Company's core markets with a retail energy product that is differentiated either by premium service (Reliant), sustainability (Green Mountain Energy) or loyalty/affinity programs (Energy Plus); (iii) optimal hedging of baseload generation and retail load operations, while retaining optionality on the Company's peaking facilities; (iv) repowering of power generation assets at premium sites; (v) investment in, and deployment of, alternative energy technologies both in its wholesale and, particularly, in and around its Retail businesses and their customers; (vi) pursuing selective acquisitions, joint ventures, divestitures and investments; and (vii) engaging in a proactive capital allocation plan focused on achieving the regular return of and on stockholder capital within the dictates of prudent balance sheet management.

Moreover, the Company believes that the American energy industry is going to be increasingly impacted by the long-term societal trend towards sustainability which is both generational and irreversible. This trend is further influenced by the information technology-driven revolution, which has enabled greater and easier personal choice in other sectors of the consumer economy and will do the same in the American energy sector over the years to come. As a result, energy consumers will have increasing personal control over from whom they buy their energy, how that energy is generated and used and what environmental impact these individual choices will have. The Company's initiatives in this area of future growth are focused on: (i) renewable generation, with a concentration in solar; (ii) electric vehicle ecosystems; (iii) customer-facing energy products and services including smart grid services, nationwide retail green electricity, unique retail sales channels involving loyalty and affinity programs and custom design, reliability services; and (iv) the construction of other forms of on-site clean power generation. The Company's advances in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in Item 1, Business - New and On-going Company Initiatives and Development Projects of the Company's 2011 Form 10-K, and this Form 10-Q.

Pending Acquisition

On July 20, 2012, the Company entered into the Merger Agreement to acquire GenOn Energy, Inc., or GenOn. GenOn, a generator of wholesale electricity, has baseload, intermediate and peaking power generation facilities using coal, natural gas and oil, totaling approximately 22,700 MW. The Company will issue, as consideration for the acquisition, 0.1216 shares of NRG common stock for each outstanding share of GenOn, including restricted stock units outstanding, on the acquisition date, except for fractional shares which will be paid in cash. Based upon total GenOn shares outstanding as of September 30, 2012, the Company expects to issue approximately 94 million shares of NRG common stock, or 29% of total common shares outstanding following the closing of the transaction.

The Merger Agreement contains customary representations, warranties and covenants of NRG and GenOn, including, among others, covenants (a) to conduct their respective businesses in the ordinary course during the interim period between the execution of the Merger Agreement and completion of the merger, (b) not to engage in certain material transactions during the interim period except with the consent of the other party, (c) that NRG will convene and hold a meeting of its stockholders to consider and vote upon the approval of the issuance of NRG common stock in the merger and the approval and adoption of the charter amendment to allow the size of NRG's Board of Directors to be increased to 16 members in connection with the closing, (d) that GenOn will convene and hold a meeting of its stockholders to consider and vote upon the adoption of the Merger Agreement, and (e) that the parties use their respective reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals and consents.

NRG and GenOn will hold their respective special meetings of stockholders on November 9, 2012. The stockholders who held shares of NRG and GenOn on Friday, October 5, 2012, will be entitled to vote at their respective special meeting on the proposals pertaining to the merger of the companies.

On September 21, 2012, the U.S. DOJ and the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. On October 25, 2012, the PUCT approved the merger. Additionally, the 90-day prior notice period to the CPUC required under California law expired on October 31, 2012.

The merger remains subject to the satisfaction or waiver of other closing conditions, including approval by the stockholders of both companies and regulatory approvals by the FERC and the NYPSC. Additionally, the companies have requested a threshold determination by the NRC that its approval is not required. The acquisition is expected to close by the first quarter of 2013.

The combined company, which will retain the name NRG Energy, Inc., will become the largest competitive power generation company in the United States with approximately 47,000 MW of fossil fuel, nuclear, solar and wind capacity across the merit order in major competitive energy markets across the United States. In 2011, the combined fleet generated approximately 105 terawatt-hours of electricity. Expected synergies include cost and operational efficiency synergies, interest savings, reduced liquidity and collateral requirements, and a greater operational scale, which will enhance the combined company's ability to revitalize its generation fleet and optimize portfolio value.

Environmental Matters

Environmental Regulatory Landscape

In 2011, a number of U.S. EPA air regulations were finalized providing more clarity to the impact on electric generating units. A number of regulations with the potential for impact are still in development or under review by the U.S. EPA: New Source Performance Standards, or NSPS, for Greenhouse Gases, or GHGs, National Ambient Air Quality Standards, or NAAQS, revisions, coal combustion byproducts, and once-through cooling. While most of these regulations have been considered for some time, the outcomes and any resulting impact on NRG cannot be fully predicted until the rules are finalized. The timing and stringency of these regulations will contribute to a framework for the retrofit of existing fossil plants and deployment of new, cleaner technologies in the next decade. See discussion below for more detail.

Air — The U.S. EPA released the Cross-State Air Pollution Rule, or CSAPR, on July 7, 2011, with additional proposed updates on October 6, 2011. CSAPR was scheduled to replace the Clean Air Interstate Rule, or CAIR, on January 1, 2012. It was designed to bring states into attainment with PM 2.5 and ozone NAAQS, reducing SO_2 and NO_x

emissions from power plants. The U.S. Court of Appeals for the District of Columbia Circuit stayed the rule on December 30, 2011, pending resolution of the numerous petitions for judicial review and leaving CAIR in effect during the stay.

On August 21, 2012, the court released their finding and CSAPR was vacated. The Court found that CSAPR violated federal law in that CSAPR requires states to reduce emissions more than their own significant contributions and the EPA wanted states to implement a Federal Implementation Plan without allowing for states to implement their own State Implementation Plans. CAIR will remain in place until EPA promulgates another regulation to replace it. The Company believes the Court decision is not material to NRG.

On February 16, 2012, the U.S. EPA finalized MATS, to control emissions of hazardous air pollutants from coal and oil fired electric generating units. Requirements include meeting the standards for mercury, acid gases, and certain metals (such as particulate matter) by April 16, 2015 on a plant wide basis with the potential for a one year extension. In April 2012, the rule was challenged on a number of issues by some states and industrial representatives. The appeal will be heard before the D.C. Circuit. NRG does not anticipate any plant impairments or capital expenditures beyond the current environmental capital expenditures schedule.

The U.S. EPA published the proposed New Source Performance Standards, or NSPS, for GHGs on April 13, 2012. The new standard, 1,000 tons of CO_2 per MWh gross, applies only to new electric generating units greater than 25 MW and provides averaging options for new units expected to install carbon capture. An exclusion for existing units minimizes the impact to NRG's coal plants.

On July 3, 2012, the EPA finalized the continued use of modified trigger levels through 2016 for GHG emissions in the Tailoring Rule. This rule maintains the current level at which projects must be permitted. While most repowering projects still trigger the permitting, the higher limit provides relief to smaller projects like the installation of back-end controls to meet other regulations.

Regulatory Matters

As operators of power plants and participants in wholesale and retail energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include the Commodities Futures Trading Commission, or CFTC, the FERC, the NRC, and the PUCT, as well as other public utility commissions in certain states where NRG's generating, thermal, or distributed generation assets are located. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO markets in which it participates. Likewise, certain NRG entities participating in the retail markets are subject to rules and regulations established by the states in which NRG entities are licensed to sell at retail. NRG must also comply with the mandatory reliability requirements imposed by the North American Electric Reliability Corporation, and the regional reliability entities in the regions where the Company operates.

NRG's operations within the ERCOT footprint are not subject to rate regulation by the FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. These operations are subject to regulation by PUCT, as well as to regulation by the NRC with respect to the Company's ownership interest in STP.

Texas Region

NRC Task Force Report — On March 11, 2012, the NRC issued Tier 1 requirements in response to the Near-Term Task Force report. Specifically, the NRC issued rules governing installation of spent fuel pool instrumentation and established mitigation strategies for beyond-design-basis external events. Additionally, the NRC issued requests for information regarding the re-evaluation of seismic and flooding hazards and the development of staffing strategies necessary for responding to an extended station blackout multi-unit event. The Company has submitted the required contingency plans and the NRC accepted the proposals. The Company anticipates being able to comply in a timely manner with all announced requirements.

ERCOT System-Wide Offer Caps — At its June 26, 2012, meeting, the PUCT approved an amendment to raise the ERCOT system-wide energy and ancillary service offer cap from $3,000 to $4,500 per MWh beginning August 1, 2012. At its October 25, 2012, meeting, the PUCT approved further increases of the system-wide offer cap effective June 1, 2013 to $5,000, escalating to $7,000 on June 1, 2014, and to $9,000 on June 1, 2015. In addition, the PUCT increased the low system offer cap to the higher of $2,000 or 50 times Houston Ship Channel gas price index, triggered when ERCOT calculates a $300,000 per MW presumed net revenue recovery in a calendar year for a gas peaking unit (Peaker Net Margin), the low cap remaining in effect for the remainder of the calendar year. In future years, the Peaker Net Margin will be established as three times the cost of new entry. The ERCOT ISO is expected to shift the Power Balance Penalty Curve, or PBPC, to match these offer cap levels. An increase in the cap on electricity prices could have a material impact on NRG's retail and wholesale operations. This is expected to be overall positive to NRG as it will potentially result in increased wholesale revenues.

Over the past several months, ERCOT has implemented a number of measures intended to ensure that real-time energy prices accurately reflect supply scarcity conditions. Specific changes include requiring that energy from reliability services (such as responsive reserves and reliability unit commitments) be offered at the system-wide offer cap, implementing floor prices during the deployment of non-spinning reserve services, and shifting 500 MWs of non-spinning reserves to responsive reserves procurement by the ISO.

On June 1, 2012, the Brattle Group issued an ERCOT sponsored report on resource adequacy. The Brattle Report provides an analysis of the current ERCOT market performance and makes numerous market design recommendations designed to incent investment in additional resources in ERCOT. The report also includes five market design options for consideration to help ensure resource adequacy. The options range from maintaining the existing energy-only market design to a forward capacity market. The PUCT has initiated a new proceeding to evaluate the Brattle Group's recommendations and indicated its intention to determine whether the current reserve margin “target” should be made a market requirement. If the reserve margin is ultimately determined to be a requirement, the PUCT will provide direction to ERCOT regarding the market measures the ISO must implement to ensure the reserve margin requirement is consistently achieved. Such measures, in keeping with the Brattle Report recommended options, would be intended to improve investment incentives for new resources in the wholesale market. The PUCT is expected to make these decisions late in 2012 or early 2013.

ERCOT Voluntary Mitigation Plan — On June 18, 2012, NRG submitted a Voluntary Mitigation Plan, or VMP, which had been agreed to by PUCT Staff, and the ERCOT Independent Market Monitor. The VMP establishes a safe harbor for energy offers from NRG's units in ERCOT's real-time market. The VMP was approved by the PUCT on July 13, 2012.

Northeast Region

New England

Forward Capacity Market — On January 19, 2012, the FERC issued an order largely denying rehearing of its prior decision addressing proposed amendments submitted by ISO New England Inc. to its Forward Capacity Market, or FCM, design, as well as two pending complaints. On March 16, 2012, the Company and other generators with interests in New England appealed the FERC's decision to the DC Circuit Court of Appeals. Briefing is currently underway.

New York

New Financial Reporting Rules in New York — On March 23, 2012, the NYPSC issued an order addressing its policy of applying “lightened” regulation to wholesale generators. The order proposed to subject wholesale generators, which would include NRG entities operating in New York, to more stringent financial reporting rules, including a requirement for generators to make an annual submission of “receipts and expenditures” to the NYPSC. Parties filed comments on the proposed financial reporting forms on July 30, 2012 and the NYPSC has not yet issued a final form.

Dunkirk Power LLC Reliability Service — On March 14, 2012, Dunkirk Power LLC, or Dunkirk Power, filed a notice with the New York Department of Public Service, or DPS, of its intent to mothball the Dunkirk Station no later than September 10, 2012. The effects of the mothball on electric system reliability were reviewed by Niagara Mohawk Power Corporation, d/b/a National Grid, or NG. As a result of those studies, NG determined that the mothball of the Dunkirk Station would have a negative impact on the reliability of the New York transmission system and that portions of the Dunkirk Station may be retained for reliability purposes via a non-market compensation arrangement. On July 12, 2012, Dunkirk Power filed a Reliability Must Run, or RMR, agreement, with the FERC. On July 20, 2012, NG and Dunkirk Power agreed on the material terms for a bilateral reliability support services, or RSS, agreement and submitted those terms to the NYPSC for rate recovery in NG's rates. On August 16, 2012, the NYPSC approved terms and on August 27, 2012, Dunkirk Power and NG entered into the RSS agreement that began on September 1, 2012. Dunkirk Power has requested that the FERC defer consideration of its RMR agreement until the NYPSC appeal period with respect to the order approving the agreement terms has run.

New York City Mitigation Order — On June 21, 2012, the FERC issued the first of two anticipated orders on the New York Independent System Operator's, or NYISO's, implementation of mitigation rules designed to prevent the exercise of buyer-side market power in the In-City capacity market. The order related primarily to the appropriate modeling assumptions that the NYISO should use in determining whether new entrants are subject to mitigation and, if so, what offer floor should apply to their capacity market bids. The FERC directed the NYISO to conduct its mitigation determinations using modeling parameters comparable to those used in the demand-curve reset process. The FERC also agreed with NRG and other generators that the NYISO needs to make its mitigation determination process more transparent and ordered appropriate changes. Finally, the FERC directed the NYISO IMM to provide a report on the effectiveness of the capacity market buyer-side market power mitigation program.

In the second anticipated order issued on September 10, 2012, the FERC found that the NYISO had not properly applied its mitigation rules to two proposed in-city generation facilities totaling over 1,000 MW (owned respectively by Astoria Energy II LLC and Bayonne Energy Center, LLC - neither of which are affiliated with the Company) and required the NYISO to redo its exemption determinations for these proposed facilities based largely on the modeling procedures presented by the Company and the other in-city generators. While the FERC did not require the NYISO to redo its determinations by a date certain, the NYISO has stated that it plans to do the redetermination for the two proposed facilities by the January 13, 2013 spot auction.

Hudson Transmission Partners Capacity Market Mitigation Complaint — On August 3, 2012, Hudson Transmission Partners, or HTP, filed a complaint at the FERC regarding the ability of its transmission cable from New Jersey to New York City to participate in the NYISO capacity markets. HTP raises two primary allegations. First, HTP alleges that the NYISO inappropriately determined that its capacity sales in the NYISO monthly spot capacity auction should be subject to a bid floor. Second, HTP asserts that even if its mitigated bid does not clear the monthly spot auction, it should still receive separate reliability compensation because the emergency transfer capacity of its cable decreases the Statewide Installed Reserve Margin, providing the NYISO an alleged reliability benefit for which HTP believes it deserves compensation. HTP's unmitigated entry into the NYISO market could have a material negative impact on NRG's existing fleet in New York City by decreasing capacity prices or by decreasing the locational capacity requirement in New York City. The NYISO's answer and other comments in response to the complaint are due November 13, 2012.

South Central Region

Entergy has announced its proposal to transfer functional control of its transmission assets to the Midwest Independent Transmission System Operator, Inc., or MISO, with a proposed transfer of control in December 2013. This transfer is subject to pending regulatory approvals. To date, the Company has publicly supported the transition of Entergy into MISO, based largely on the Company's positive experience with proven Day 2 Markets. The Company has been an active participant in the stakeholder processes surrounding Entergy's integration into MISO, including the discussions involving MISO's allocation of financial transmission rights upon integration, and is working to mitigate any potential negative economic impacts of the MISO integration.

CFTC — Dodd-Frank Act Developments

Over the past months, the CFTC has voted to adopt a range of final rules under the Dodd-Frank Wall Street Reform and Consumer Protection Act, commonly known as the “Dodd-Frank Act.” The Company is reviewing the final and proposed rules that the CFTC, SEC and other federal regulators have issued or will issue under the Dodd-Frank Act, including, without limitation, the margin rules, the end-user exemption and the definitions of “swap,” “swap dealer” and “major swap participant.” The Company is also evaluating whether and how these rules may apply to its business. The Company is an end-user of swaps and does not expect that its commercial activity will result in its being designated as either a swap dealer or major swap participant.

Changes in Accounting Standards

See Note 2, Summary of Significant Accounting Policies, to this Form 10-Q as found in Item 1 for a discussion of recent accounting developments.

Consolidated Results of Operations

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Three months ended September 30, 2012	2011	Change %	Nine months ended September 30, 2012	2011	Change %
Operating Revenues						
Energy revenue [a]	$626	$465	35 %	$1,603	$1,592	1 %
Capacity revenue [a]	194	196	(1)	557	564	(1)
Retail revenue	1,860	1,882	(1)	4,576	4,526	1
Mark-to-market for economic hedging activities	(377)	81	N/A	(458)	149	N/A
Contract amortization	(10)	(18)	44	(69)	(109)	37
Other revenues [b]	38	68	(44)	150	225	(33)
Total operating revenues	2,331	2,674	(13)	6,359	6,947	(8)
Operating Costs and Expenses						
Generation cost of sales [a]	694	853	(19)	1,655	2,017	(18)
Retail cost of sales [a]	847	871	(3)	2,197	2,163	2
Mark-to-market for economic hedging activities	(118)	40	N/A	(174)	(68)	156
Contract and emissions credit amortization [c]	13	16	(19)	32	37	(14)
Other cost of operations	290	273	6	908	836	9
Total cost of operations	1,726	2,053	(16)	4,618	4,985	(7)
Depreciation and amortization	239	238	—	703	665	6
Impairment charge on emission allowances	—	160	(100)	—	160	(100)
Selling, general and administrative	253	169	50	681	479	42
Acquisition-related transaction and integration costs	18	—	N/A	18	—	N/A
Development costs	9	11	(18)	26	32	(19)
Total operating costs and expenses	2,245	2,631	(15)	6,046	6,321	(4)
Operating Income	86	43	100	313	626	(50)
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	4	16	(75)	26	26	—
Impairment charge on investment	(1)	(3)	(67)	(2)	(495)	(100)
Other income, net	10	5	100	14	13	8
Loss on debt extinguishment	(41)	(32)	28	(41)	(175)	(77)
Interest expense	(163)	(164)	(1)	(495)	(504)	(2)
Total other expense	(191)	(178)	7	(498)	(1,135)	(56)
Loss before Income Tax Expense	(105)	(135)	N/A	(185)	(509)	(64)
Income tax benefit	(113)	(80)	41	(246)	(815)	(70)
Net Income/(Loss)	8	(55)	(115)	61	306	(80)
Less: Net income attributable to noncontrolling interest	9	—	N/A	18	—	N/A
Net (Loss)/Income Attributable to NRG Energy, Inc.	$(1)	$(55)	(98)	$43	$306	(86)
Business Metrics						
Average natural gas price — Henry Hub ($/MMBtu)	$2.81	$4.20	(33)%	$2.59	$4.21	(38)%

(a) Includes realized gains and losses from financially settled transactions.

(b) Includes unrealized trading gains and losses.

(c) Includes amortization of SO_2 and NO_x credits and excludes amortization of Regional Greenhouse Gas Initiative, or RGGI, credits.

N/A - Not Applicable

56

Management’s discussion of the results of operations for the three months ended September 30, 2012, and 2011

Income/(Loss) before income tax expense — The pre-tax loss of $105 million for the three months ended September 30, 2012, compared to a pre-tax loss of $135 million for the three months ended September 30, 2011, primarily reflects:

- in the current year, a $164 million increase in Conventional Generation gross margin, a $87 million increase in Retail gross margin, and a $45 million increase in Alternative Energy gross margin; offset by
- a $118 million increase in operating costs primarily from increased selling, general and administrative expenses and acquisition-related transaction and integration costs,
- a $300 million decrease in net mark-to-market results from economic hedging activities, and
- a $160 million impairment charge on emissions allowances in the prior year.

Net income — The increase in net income of $63 million primarily reflects the drivers discussed as well as an income tax benefit for the three months ended September 30, 2012, of $113 million, compared with an income tax benefit of $80 million in the comparable period.

Conventional Generation gross margin

The following is a discussion of gross margin for NRG's Conventional Generation businesses, adjusted to eliminate intersegment activity, primarily with the Retail businesses.

	Three months ended September 30, 2012								
	Conventional Generation								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$767	$ 183	$196	$43	$4	$1,193	$ 54	$ (621)	$ 626
Capacity revenue	27	84	59	31	5	206	—	(12)	194
Other revenue	(16)	5	(3)	4	59	49	1	(12)	38
Generation revenue	778	272	252	78	68	1,448	55	$ (645)	$ 858
Generation cost of sales	(306)	(145)	(187)	(35)	(26)	(699)	—	$ 5	$ (694)
Generation gross margin	$472	$ 127	$65	$43	$42	$749	$ 55		
Business Metrics									
MWh sold (in thousands)	13,061	2,592	6,021	863			469		
MWh generated (in thousands)	11,949	2,140	4,474	863			469		
Average on-peak market power prices ($/MWh) (a)(b)	$31.92	$ 47.29	$31.07	$38.77			N/A		

(a) Average on-peak market power prices calculated based on average settled market prices in the following zones: for Texas region, in ERCOT - Houston and ERCOT - North; for Northeast region, in NYISO - West, NYISO - New York City, ISO - NE -

Mass Hub, PJM - West Hub and PJM - DPL; and for West region, in CAISO - NP15 and CAISO - SP15.

(b) Average on-peak market power prices for South Central region are calculated based on average day ahead market prices for "into Entergy" as published in the Platts Megawatt Daily report.

	Three months ended September 30, 2011								
	Conventional Generation								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$724	$207	$205	$19	$13	$1,168	$10	$ (713)	$465
Capacity revenue	9	79	61	33	18	200	—	(4)	196
Other revenue	20	1	6	(2)	50	75	—	(7)	68
Generation revenue	753	287	272	50	81	1,443	10	$ (724)	$729
Generation cost of sales	(431)	(176)	(197)	(9)	(45)	(858)	—	$ 5	$ (853)
Generation gross margin	$322	$111	$75	$41	$36	$585	$10		
Business Metrics									
MWh sold (in thousands)	14,429	3,191	5,749	134			251		
MWh generated (in thousands)	13,990	2,611	4,488	134			251		
Average on-peak market power prices ($/MWh) [(a)(b)]	$108.89	$59.05	$42.53	$40.95			N/A		

(a) Average on-peak market power prices calculated based on average settled market prices in the following zones: for Texas region, in ERCOT - Houston and ERCOT - North; for Northeast region, in NYISO - West, NYISO - New York City, ISO - NE - Mass Hub, PJM - West Hub and PJM - DPL; and for West region, in CAISO - NP15 and CAISO - SP15.
(b) Average on-peak market power prices for South Central region are calculated based on average day ahead market prices for "into Entergy" as published in the Platts Megawatt Daily report.

	Three months ended September 30,			
Weather Metrics	Texas	Northeast	South Central	West
2012				
CDDs [(c)]	1,594	586	1,096	724
HDDs [(c)]	—	122	41	44
2011				
CDDs	1,877	585	1,134	606
HDDs	—	86	44	52
30 year average				
CDDs	1,485	430	997	506
HDDs	5	159	33	108

(c) National Oceanic and Atmospheric Administration-Climate Prediction Center - A Cooling Degree Day, or CDD, represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. A Heating Degree Day, or HDD, represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Conventional Generation gross margin — increased by $164 million, including intercompany sales, during the three months ended September 30, 2012, compared to the same period in 2011, due to:

Increase in Texas region	$150
Increase in Northeast region	16
Decrease in South Central region	(10)
Increase in West region	2
Other [(a)]	6
	$164

(a) Other gross margin primarily represents revenues from the maintenance services business, which are eliminated in consolidation.

The increase in gross margin in the Texas region was driven by:

Impact of fewer unplanned outages during periods of high scarcity pricing as well as more effective hedging and trading optimization activities	$96
Higher gross margin from a reduction in delivered fuel costs and an increase in average realized energy prices	80
Higher revenue due to additional bi-lateral contracts with load serving entities and contracts with our Retail businesses	18
Change in unrealized trading activities	(28)
Lower gross margin from a decrease in coal generation driven by higher outages in 2012	(11)
Other	(5)
	$150

The increase in gross margin in the Northeast region was driven by:

Higher gross margin from favorable pricing on certain load-serving contracts, as well as additional load contracts with our Retail businesses	$5
Increase in capacity revenue due to higher cleared auction prices in PJM	4
Change in unrealized trading activities and other	7
	$16

The decrease in gross margin in the South Central region was driven by:

Lower gross margin from a decrease in average realized prices	$(20)
Lower gross margin from a decrease in coal generation	(5)
Higher gross margin from higher utilization of gas generation due to lower gas prices and higher overall sales volumes	33
Change in unrealized trading activities and other	(18)
	$(10)

The increase in gross margin in the West region was driven by:

Change in unrealized trading activities	$6
Decrease in gross margin due to a decrease in realized prices, offset in part by increased run time at Encina driven by competitor's plant outages in the region	(2)
Decreased capacity revenue due to lower prices for Encina	(2)
	$2

Retail gross margin

The following is a detailed discussion of retail gross margin for NRG's Retail business segment.

Selected Income Statement Data

	Three months ended September 30,	
(In millions except otherwise noted)	2012	2011
Operating Revenues		
Mass revenues	$1,201	$1,198
Commercial and Industrial revenues	605	598
Supply management revenues	55	88
Retail operating revenues (a)(b)	1,861	1,884
Retail cost of sales (c)	1,477	1,587
Retail gross margin	$384	$297
Business Metrics		
Electricity sales volume — GWh		
Mass	9,838	9,729
Commercial and Industrial (d)	8,495	8,014
Electricity sales volume — GWh		
Texas	16,493	17,413
All other regions	1,840	330
Average retail customers count (in thousands, metered locations)		
Mass (e)	2,052	1,773
Commercial and Industrial (d)	117	87
Retail customers count (in thousands, metered locations)		
Mass (e)	2,073	1,788
Commercial and Industrial (d)	119	87
Weather Metrics		
CDDs (f)	1,708	2,050
HDDs (f)	—	—

(a) Includes customers of the Texas General Land Office for which the Company provides services, as well as sales to utility partner customers.

(b) Includes intercompany sales of $1 million and $2 million, respectively, representing sales from Retail to the Texas region.

(c) Includes intercompany purchases of $630 million and $716 million, respectively.

(d) Includes customers of the Texas General Land Office for which the Company provides services.

(e) Excludes utility partner customers.

(f) The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Retail serves its customer base.

- Retail gross margin — Retail gross margin increased $87 million for the three months ended September 30, 2012, compared to the same period in 2011, driven by:

Acquisition of Energy Plus in September 2011	$41
Favorable impact of fewer scarcity price increases during times of excessive load compared to prior year, offset by generally milder weather in 2012	40
Increase in usage and customer count	19
Decrease in unit margins, driven primarily by weather-related risk management activities, as well as lower pricing and lower supply costs on acquisitions and renewals	(13)
	$87

- Trends — Customer counts increased by approximately 63,000 since June 30, 2012, which was primarily due to marketing efforts in ERCOT and new territories. While cooling and heating degree days in both periods resulted in higher than normal customer usage, weather in 2011 was warmer than in 2012. The weather resulted in higher customer usage of 1% and 13% in 2012 and 2011, respectively, when compared to ten-year normal weather. In addition, there were increases in Texas in Transmission and Distribution Service Provider rates that will remain in effect for several years. These costs are passed through to Retail customers.

Alternative Energy gross margin

NRG's Alternative Energy business segment, which is comprised mainly of the solar and wind businesses, had gross margin of $55 million for the three months ended September 30, 2012, compared to gross margin of $10 million for the same period in 2011. The increase in gross margin primarily resulted from the addition of the Roadrunner facility, which began commercial operations in late 2011, the addition of the first 230 MW of Agua Caliente, which reached commercial operations in 2012, and an increase in gross margin from Distributed Solar.

Mark-to-market for Economic Hedging Activities
Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges. Total net mark-to-market results decreased by $300 million during the three months ended September 30, 2012, compared to the same period in 2011.
The breakdown of gains and losses included in operating revenues and operating costs and expenses by region was as follows:

	Three months ended September 30, 2012							
	Retail	Texas	Northeast	South Central	West	Alternative Energy	Elimination[(a)]	Total
	(In millions)							
Mark-to-market results in operating revenues								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(2)	$(2)	$1	$10	$5	$—	$(19)	$(7)
Net unrealized gains/(losses) on open positions related to economic hedges	13	101	1	2	4	1	(492)	(370)
Total mark-to-market gains/(losses) in operating revenues	$11	$99	$2	$12	$9	$1	$(511)	$(377)
Mark-to-market results in operating costs and expenses								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(103)	$3	$2	$1	$—	$—	$19	$(78)
Reversal of gain positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions	(15)	—	—	—	—	—	—	(15)
Net unrealized (losses)/gains on open positions related to economic hedges	(308)	9	7	11	—	—	492	211
Total mark-to-market (losses)/gains in operating costs and expenses	$(426)	$12	$9	$12	$—	$—	$511	$118

(a) Represents the elimination of the intercompany activity between the Retail businesses and the Conventional Generation regions and Alternative Energy.

	Three months ended September 30, 2011						
	Retail	Texas	Northeast	South Central	West	Elimination[a]	Total
	(In millions)						
Mark-to-market results in operating revenues							
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	$—	$44	$5	$7	$—	$(33)	$23
Net unrealized gains/(losses) on open positions related to economic hedges	1	20	6	(6)	(5)	42	58
Total mark-to-market gains/(losses) in operating revenues	$1	$64	$11	$1	$(5)	$9	$81
Mark-to-market results in operating costs and expenses							
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$(2)	$(1)	$(1)	$(2)	$—	$33	$27
Reversal of gain positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions	(11)	—	—	—	—	—	(11)
Net unrealized (losses)/gains on open positions related to economic hedges	(23)	4	(3)	8	—	(42)	(56)
Total mark-to-market (losses)/gains in operating costs and expenses	$(36)	$3	$(4)	$6	$—	$(9)	$(40)

(a) Represents the elimination of the intercompany activity between the Retail businesses and the Conventional Generation regions.

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the three months ended September 30, 2012, the net losses on open positions were due to increases in forward natural gas and power prices.

For the three months ended September 30, 2011, the net gains on open positions were due to a decrease in forward power and gas prices. The reversal of gain positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions were valued using forward prices on the acquisition dates. The roll-off amounts were offset by realized net losses at the settled prices and lower net costs of physical power which are reflected in operating costs and expenses during the same period.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the three months ended September 30, 2012, and 2011. The realized and unrealized financial and physical trading results are included in operating revenue. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Three months ended September 30,	
(In millions)	2012	2011
Trading gains/(losses)		
Realized	$40	$(43)
Unrealized	(18)	8

Total trading gains/(losses)	$22	$(35)

62

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase accounting and the favorable change of $8 million as compared to the prior period in 2011 related primarily to lower contract amortization for Reliant Energy and Green Mountain Energy of $5 million and $3 million, respectively.

Other Operating Costs

	Retail	Texas	Northeast	South Central	West	Other	Alternative Energy	Eliminations/Corporate	Total
	(In millions)								
Three months ended September 30, 2012	$66	$116	$56	$22	$11	$22	$7	$ (10)	$290
Three months ended September 30, 2011	$56	$113	$57	$25	$8	$18	$5	$ (9)	$273

Other operating costs increased by $17 million for the three months ended September 30, 2012, compared to the same period in 2011, due to:

Increase in Retail operations and maintenance expense	$11
Increase in Texas region operations and maintenance expense	3
Other	3
	$17

Retail operations and maintenance expense — increased primarily due to the acquisition of Energy Plus in September 2011 as well as increased customer billing costs from an increase in customer counts.

Texas operations and maintenance — increased due to maintenance spending and outage work in 2012 at S.R. Bertron to return two units to service and related to timing of maintenance work in 2012.

Impairment Charge on Emission Allowances

As described in Note 24, Environmental Matters, to the Company's 2011 Form 10-K, NRG recorded an impairment charge of $160 million in the three months ended September 30, 2011, on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment charge reflects the write-off of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $84 million for the three months ended September 30, 2012, compared to the same period in 2011, which was due primarily to the following:

- Selling, general and administrative costs of $27 million for Energy Plus which was acquired in September 2011;
- Increase in marketing costs of $13 million associated with customer growth efforts and new market expansion by corporate and the Retail businesses;
- Increase in labor costs of $4 million for additional solar projects and acquired Distributed Solar businesses;
- The impact of a settlement with the EPA regarding LaGen of $14 million; and
- Additional costs associated with new business initiatives of $6 million, consulting, legal and other costs of $8 million and $12 million of additional labor costs.

Acquisition-related Transaction and Integration Costs

As previously announced, NRG entered into an agreement to acquire GenOn, which is expected to close by the first quarter of 2013. In connection with the pending transaction, NRG has incurred transaction and integration costs of $18 million in the three months ended September 30, 2012, consisting primarily of financial consulting fees and legal expenses.

Equity in Earnings of Unconsolidated Affiliates

NRG's equity earnings from unconsolidated affiliates were $4 million for the three months ended September 30, 2012, compared to $16 million for the same period in 2011 primarily due to changes in the fair value of Sherbino's forward gas contract as well as additional equity losses from investments in emerging energy technology companies.

Impairment Charge on Investment

As discussed in more detail in Note 4, Nuclear Innovation North America LLC Developments, Including Impairment Charge, of the Company's 2011 Form 10-K, the devastating March 2011 earthquake and tsunami in Japan, which in turn triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station, caused NRG to evaluate its investment in NINA for impairment. Consequently, NRG deconsolidated its investment in NINA and took an impairment charge in the first quarter of 2011 equal to the balance of its investment in NINA, or $481 million. To support NINA's ongoing work, NRG contributed an additional $3 million into NINA during the third quarter of 2011, which NRG also expensed as an impairment charge.

Loss on Debt Extinguishment

A loss on debt extinguishment of the 2017 Senior Notes of $41 million was recorded in the three months ended September 30, 2012, while a loss on debt extinguishment for the Senior Credit Facility of $32 million was recorded in the three months ended September 30, 2011. These losses primarily consisted of the premiums paid on redemption and the write-off of previously deferred financing costs.

Interest Expense

NRG's interest expense decreased by $1 million compared to the same period in 2011 due to the following:

Increase/(decrease) in interest expense	(In millions)
Increase from additional project financings	$17
Decrease for higher capitalized interest	(14)
Other	(4)
Total	$(1)

Income Tax Benefit

For the three months ended September 30, 2012, NRG recorded an income tax benefit of $113 million on pre-tax loss of $105 million. For the same period in 2011, NRG recorded an income tax benefit of $80 million on a pre-tax loss of $135 million. The effective tax rate was 107.6% and 59.3% for the three months ended September 30, 2012, and 2011, respectively.

For the three months ended September 30, 2012, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of ITCs from the Company's Agua Caliente solar project in Arizona and PTCs generated from certain Texas wind facilities.

For the three months ended September 30, 2011, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to a reduction in the valuation allowance.

Management's discussion of the results of operations for the nine months ended September 30, 2012, and 2011

Loss before income tax expense — The pre-tax loss of $185 million for the nine months ended September 30, 2012, compared to a pre-tax loss of $509 million for the nine months ended September 30, 2011, primarily reflects:

- in the current year, a decrease in operating income of $313 million as compared to the prior year period, which reflects:
  - a decrease from net mark-to-market results for economic hedging activities of $501 million; and
  - increased operating costs of $324 million including operations and maintenance expense, depreciation and amortization, selling, general and administrative costs and acquisition-related transaction and integration costs; offset by:
  - an increase in gross margin of $342 million comprised of an increase in Conventional Generation gross margin of $127 million, an increase in Retail gross margin of $134 million and an increase in Alternative Energy gross margin of $81 million; and
  - in the prior year, a $160 million impairment charge on emissions allowances.
- in addition, the prior year also reflects:
  - a $495 million loss on the impairment of NRG's investment in NINA, and
  - a $175 million loss on the extinguishment of the 2014 Senior Notes, the 2016 Senior Notes and the Senior Credit Facility.

Net income — The decrease in net income of $263 million primarily reflects the drivers discussed above offset by an income tax benefit for the nine months ended September 30, 2012, of $246 million, which reflects the impact of the ITC for Agua Caliente, compared with an income tax benefit of $815 million in the comparable period, which primarily reflects the resolution of the federal tax audit in June 2011 and the related recognition of previously uncertain tax benefits.

Conventional Generation gross margin

The following is a discussion of gross margin for NRG's Conventional Generation businesses, adjusted to eliminate intersegment activity, primarily with the Retail businesses.

	Nine months ended September 30, 2012								
	Conventional Generation								
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$1,866	$ 370	$436	$85	$38	$2,795	$ 112	$ (1,304)	$ 1,603
Capacity revenue	64	211	181	91	40	587	—	(30)	557
Other revenue	4	14	(7)	4	185	200	2	(52)	150
Generation revenue	1,934	595	610	180	263	3,582	114	$ (1,386)	$ 2,310
Generation cost of sales	(752)	(310)	(424)	(63)	(119)	(1,668)	—	$ 13	$ (1,655)
Generation gross margin	$1,182	$ 285	$186	$117	$144	$1,914	$ 114		
Business Metrics									
MWh sold (in thousands)	33,935	5,494	14,699	1,618			1,434		
MWh generated (in thousands)	28,796	4,286	12,733	1,618			1,434		
Average on-peak market power prices ($/MWh) [(a)(b)]	$29.43	$ 40.44	$27.59	$31.49			N/A		

(a) Average on-peak market power prices calculated based on average settled market prices in the following zones: for Texas region, in ERCOT - Houston and ERCOT - North; for Northeast region, in NYISO - West, NYISO - New York City, ISO - NE - Mass Hub, PJM - West Hub and PJM - DPL; and for West region, in CAISO - NP15 and CAISO - SP15.
(b) Average on-peak market power prices for South Central region are calculated based on average day ahead market prices for "into Entergy" as published in the Platts Megawatt Daily report.

(In millions except otherwise noted)	Nine months ended September 30, 2011 Conventional Generation Texas	Northeast	South Central	West	Other	Subtotal	Alternative Energy	Eliminations/Corporate	Consolidated Total
Energy revenue	$1,991	$503	$435	$28	$43	$3,000	$32	$ (1,440)	$1,592
Capacity revenue	19	228	183	89	54	573	—	(9)	564
Other revenue	65	14	14	3	148	244	1	(20)	225
Generation revenue	2,075	745	632	120	245	3,817	33	$ (1,469)	$2,381
Generation cost of sales	(995)	(449)	(432)	(14)	(140)	(2,030)	—	$ 13	$(2,017)
Generation gross margin	$1,080	$296	$200	$106	$105	$1,787	$33		
Business Metrics									
MWh sold (in thousands)	38,057	8,127	13,223	189			914		
MWh generated (in thousands)	36,348	6,522	12,147	189			914		
Average on-peak market power prices ($/MWh) (a)(b)	$66.81	$57.02	$39.93	$37.06			N/A		

(a) Average on-peak market power prices calculated based on average settled market prices in the following zones: for Texas region, in ERCOT - Houston and ERCOT - North; for Northeast region, in NYISO - West, NYISO - New York City, ISO - NE - Mass Hub, PJM - West Hub and PJM - DPL; and for West region, in CAISO - NP15 and CAISO - SP15.
(b) Average on-peak market power prices for South Central region are calculated based on average day ahead market prices for "into Entergy" as published in the Platts Megawatt Daily report.

Weather Metrics	Nine months ended September 30, Texas	Northeast	South Central	West
2012				
CDDs (c)	2,843	752	1,761	844
HDDs (c)	816	3,317	1,564	1,935
2011				
CDDs	3,197	749	1,796	676
HDDs	1,171	3,978	2,157	2,193
30 year average				
CDDs	2,434	534	1,486	663
HDDs	1,220	4,126	2,246	2,164

(c) National Oceanic and Atmospheric Administration-Climate Prediction Center - A Cooling Degree Day, or CDD, represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. A Heating Degree Day, or HDD, represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

66

Conventional Generation gross margin — increased by $127 million, including intercompany sales, during the nine months ended September 30, 2012, compared to the same period in 2011, due to:

Increase in Texas region	$102
Decrease in Northeast region	(11)
Decrease in South Central region	(14)
Increase in West region	11
Other [(a)]	39
	$127

(a) Other gross margin primarily represents revenues from the maintenance services business, which are eliminated in consolidation.

The increase in gross margin in the Texas region was driven by:

Impact of fewer unplanned outages during periods of high scarcity pricing as well as more effective hedging and trading optimization activities	$96
Higher gross margin driven by higher average realized energy prices and a decrease in delivered fuel costs	54
Higher revenue due to additional bi-lateral contracts with load serving entities and contracts with our Retail businesses	45
Lower gross margin from a decrease in coal and nuclear generation driven by higher unplanned outage hours in 2012	(54)
Change in unrealized trading activities	(42)
Other	3
	$102

The decrease in gross margin in the Northeast region was driven by:

Lower gross margin from coal plants due to a 47% decrease in generation, resulting from the region's power generation switching from coal to gas plants	$(16)
Lower gross margin from coal plants due to a 7% increase in delivered coal prices	(11)
Lower capacity revenue due to 5% lower realized prices, due mainly to lower cleared auction prices in PJM, and slightly lower volumes, offset in part by additional revenue from the Dunkirk RSS contract.	(16)
Higher gross margin from favorable pricing on certain load-serving contracts, as well as additional load contracts with our Retail businesses	34
Other	(2)
	$(11)

The decrease in gross margin in the South Central region was driven by:

Lower gross margin from a decrease in coal generation as a result of lower gas prices	$(43)
Lower gross margin from a decrease in average realized merchant prices	(61)
Higher gross margin from higher utilization of gas generation due to lower gas prices and higher overall sales volumes	125
Change in unrealized trading activities and other	(35)
	$(14)

The increase in gross margin in the West region was driven by:

Higher gross margin from increased run time at Encina driven by competitor's plant outages in the region and increased run time at the remaining plants in the region	$11
Higher capacity margin due to the recognition of contingent rent for Long Beach	5
Decreased capacity revenue due to lower prices for Encina	(3)
Decrease in fuel sales compared to 2011	(2)

$11

67

Retail gross margin

The following is a detailed discussion of retail gross margin for NRG's Retail business segment.

Selected Income Statement Data

	Nine months ended September 30,	
(In millions except otherwise noted)	2012	2011
Operating Revenues		
Mass revenues	$2,902	$2,795
Commercial and Industrial revenues	1,557	1,581
Supply management revenues	120	154
Retail operating revenues [a][b]	4,579	4,530
Retail cost of sales [c]	3,521	3,606
Retail gross margin	$1,058	$924
Business Metrics		
Electricity sales volume — GWh		
Mass	23,301	22,198
Commercial and Industrial [d]	22,459	21,521
Electricity sales volume — GWh		
Texas	41,703	43,077
All other regions	4,057	642
Average retail customers count (in thousands, metered locations)		
Mass [e]	2,021	1,780
Commercial and Industrial [d]	113	90
Retail customers count (in thousands, metered locations)		
Mass [e]	2,073	1,788
Commercial and Industrial [d]	119	87
Weather Metrics		
CDDs [f]	3,112	3,516
HDDs [f]	613	987

(a) Includes customers of the Texas General Land Office for which the Company provides services, as well as sales to utility partner customers.

(b) Includes intercompany sales of $3 million and $4 million, respectively, representing sales from Retail to the Texas region .

(c) Includes intercompany purchases of $1,324 million and $1,443 million, respectively.

(d) Includes customers of the Texas General Land Office for which the Company provides services.

(e) Excludes utility partner customers.

(f) The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Retail serves its customer base.

- Retail gross margin — Retail gross margin increased $134 million for the nine months ended September 30, 2012, compared to the same period in 2011, driven by:

Acquisition of Energy Plus in September 2011	$105	
Increase in usage and customer count	38	
Unfavorable impact of weather-related risk management activities	(25	)
Favorable impact of fewer scarcity price increases during times of excessive load compared to prior year, offset by generally milder weather in 2012	31	
Decrease in unit margins driven by the impact of lower pricing and lower supply costs on acquisitions and renewals	(15	)

$134

- Trends — Customer counts increased by approximately 124,000 since December 31, 2011, which was primarily due to expansion into new territories and marketing efforts. While cooling and heating degree days in both periods resulted in higher than normal customer usage, weather in 2012 was milder than in 2011. The weather resulted in higher customer usage of 4% and 13% in 2012 and 2011, respectively, when compared to ten-year normal weather. In addition, there were increases in Texas in Transmission and Distribution Service Provider rates that will remain in effect for several years. These costs are passed through to Retail customers.

Alternative Energy gross margin

NRG's Alternative Energy business segment, which is comprised mainly of the solar and wind businesses, had gross margin of $114 million for the nine months ended September 30, 2012, compared to gross margin of $33 million for the same period in 2011. The increase in gross margin primarily resulted from the addition of the Roadrunner facility, which began commercial operations in late 2011, the addition of the first 230 MW of Agua Caliente, which reached commercial operations in 2012, and an increase in gross margin from Distributed Solar.

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges. Total net mark-to-market results decreased by $501 million during the nine months ended September 30, 2012, compared to the same period in 2011.

The breakdown of gains and losses included in operating revenues and operating costs and expenses by region was as follows:

	Nine months ended September 30, 2012							
	Retail	Texas	Northeast	South Central	West	Alternative Energy	Elimination[a]	Total
	(In millions)							
Mark-to-market results in operating revenues								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(5)	$(330)	$2	$31	$7	$—	$65	$(230)
Net unrealized gains/(losses) on open positions related to economic hedges	1	(142)	1	(3)	(2)	—	(83)	(228)
Total mark-to-market (losses)/gains in operating revenues	$(4)	$(472)	$3	$28	$5	$—	$(18)	$(458)
Mark-to-market results in operating costs and expenses								
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	$112	$12	$8	$3	$—	$—	$(65)	$70
Reversal of loss positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions	5	—	—	—	—	—	—	5
Net unrealized gains/(losses) on open positions related to economic hedges	99	(47)	(4)	(32)	—	—	83	99
Total mark-to-market gains/(losses) in operating costs and expenses	$216	$(35)	$4	$(29)	$—	$—	$18	$174

(a) Represents the elimination of the intercompany activity between the Retail businesses and the Conventional Generation regions and Alternative Energy.

	Nine months ended September 30, 2011						
	Retail	Texas	Northeast	South Central	West	Elimination[a]	Total
	(In millions)						
Mark-to-market results in operating revenues							
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(1)	$(25)	$16	$20	$(1)	$17	$26
Net unrealized gains/(losses) on open positions related to economic hedges	4	99	9	(12)	3	20	123
Total mark-to-market gains in operating revenues	$3	$74	$25	$8	$2	$37	$149
Mark-to-market results in operating costs and expenses							
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$70	$1	$(5)	$(3)	$—	$(17)	$46
Reversal of loss positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions	60	—	—	—	—	—	60
Net unrealized (losses)/gains on open positions related to economic hedges	(55)	20	1	16	—	(20)	(38)
Total mark-to-market gains/(losses) in operating costs and expenses	$75	$21	$(4)	$13	$—	$(37)	$68

(a) Represents the elimination of the intercompany activity between the Retail businesses and the Conventional Generation regions.

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the nine months ended September 30, 2012, the net losses on open positions were due primarily to decreases in forward coal prices.

For the nine months ended September 30, 2011, the net gains on open positions were due to a decrease in forward power and gas prices. The reversal of loss positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions were valued using forward prices on the acquisition dates. The roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in operating costs and expenses during the same period.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the nine months ended September 30, 2012, and 2011. The realized and unrealized financial and physical trading results are included in operating revenue. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Nine months ended September 30,	
(In millions)	2012	2011
Trading gains/(losses)		
Realized	$71	$(28)
Unrealized	(12)	44

Total trading gains	$59	$16

70

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase accounting and the favorable change of $40 million, as compared to the prior period in 2011, related primarily to lower contract amortization of $26 million and $14 million for Reliant Energy and Green Mountain Energy, respectively.

Other Operating Costs

	Retail	Texas	Northeast	South Central	West	Other	Alternative Energy	Eliminations/Corporate	Total
	(In millions)								
Nine months ended September 30, 2012	$183	$393	$167	$73	$42	$79	$18	$ (47)	$908
Nine months ended September 30, 2011	$156	$356	$164	$68	$44	$53	$12	$ (17)	$836

Other operating costs increased by $72 million for the nine months ended September 30, 2012, compared to the same period in 2011, due to:

Increase in Texas region operations and maintenance expense	$38
Increase in Retail operations and maintenance expense	26
Increase in Alternative Energy region operations and maintenance expense	7
Decrease in Northeast region operations and maintenance expense	(8)
Increase in property tax expense	14
Other	(5)
	$72

Texas operations and maintenance — increased primarily due to maintenance spending and outage work in 2012 at S.R. Bertron to return two units to service, as well as timing of planned and unplanned outages in the region.
Retail operations and maintenance expense — increased $12 million due to the acquisition of Energy Plus in September 2011 and increased due to additional customer billing costs from an increase in customer counts.
Alternative Energy operations and maintenance expense — increased as additional solar facilities began commercial operations in 2012.
Northeast operations and maintenance expense — decreased in part because the prior year reflects incremental costs associated with headcount reductions.
Property tax expense — increased primarily for $11 million in the Northeast region due to a reduction in property tax benefit from the New York State Empire Zone program. The reduction reflects the criteria in determining the amount of the tax credit and the annual reduction of 20% beginning in 2012 until the expiration of the program in 2016.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $38 million for the nine months ended September 30, 2012, compared to the same period in 2011. This was primarily due to additional depreciation related to solar facilities which commenced commercial operations in late 2011 and early 2012, as well as the amortization of the intangibles acquired in connection with the acquisition of Energy Plus.

Impairment Charge on Emission Allowances

As described in Note 24, Environmental Matters, to the Company's 2011 Form 10-K, NRG recorded an impairment charge of $160 million in the three months ended September 30, 2011, on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment charge reflects the write-off of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $202 million for the nine months ended September 30, 2012, compared to the same period in 2011, which was due primarily to the following:

- Selling, general and administrative costs of $66 million for Energy Plus which was acquired in September 2011;
- Expected cash payment related to the CDWR settlement of $20 million expensed during the period;
- Transaction costs of $9 million associated with the sale of 49% of Agua Caliente;
- Increase in marketing costs of $40 million associated with customer growth efforts and new market expansion by corporate and the Retail businesses;
- Increase in labor costs of $10 million for additional solar projects and acquired Distributed Solar businesses;
- The impact of a settlement with the EPA regarding LaGen of $14 million; and
- Additional costs associated with new business initiatives of $11 million, consulting and legal costs of $5 million and $27 million of additional labor costs.

Acquisition-related Transaction and Integration Costs

As previously announced, NRG entered into an agreement to acquire GenOn, which is expected to close by the first quarter of 2013. In connection with the pending transaction, NRG has incurred transaction and integration costs of $18 million in the nine months ended September 30, 2012, consisting primarily of financial consulting fees and legal expenses.

Impairment Charge on Investment

As discussed in more detail in Note 4, Nuclear Innovation North America LLC Developments, Including Impairment Charge, of the Company's 2011 Form 10-K, the March 2011 earthquake and tsunami in Japan, which in turn triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station, caused NRG to evaluate its investment in NINA for impairment. Consequently, NRG deconsolidated its investment in NINA and took an impairment charge in the first quarter of 2011 equal to the balance of its investment in NINA. To support NINA's ongoing work, NRG contributed an additional $14 million into NINA during the nine months ended September 30, 2011. As a result, NRG recorded an impairment charge of $495 million in the nine months ended September 30, 2011.

Loss on Debt Extinguishment

A loss on debt extinguishment of the 2017 Senior Notes of $41 million was recorded in the nine months ended September 30, 2012, while a loss on debt extinguishment of the 2014 Senior Notes, the 2016 Senior Notes and the Senior Credit Facility of $175 million was recorded in the nine months ended September 30, 2011. These losses primarily consisted of the premiums paid on redemption and the write-off of previously deferred financing costs.

Interest Expense

NRG's interest expense decreased by $9 million for the nine months ended September 30, 2012, compared to the same period in 2011 due to the following:

Increase/(decrease) in interest expense	(In millions)	
Decrease for 2014 Senior Notes and 2016 Senior Notes redeemed in 2011	$(82	)
Increase for 2019 and 2021 Senior Notes issued in May 2011	60	
Decrease for higher capitalized interest	(47	)

Increase from additional project financings	34
Increase in derivative interest expense primarily for the Alpine interest rate swaps	14
Increase for 2018 Senior Notes issued in January 2011	6
Other	6
Total	$(9)

Income Tax Benefit

For the nine months ended September 30, 2012, NRG recorded an income tax benefit of $246 million on a pre-tax loss of $185 million. For the same period in 2011, NRG recorded an income tax benefit of $815 million on a pre-tax loss of $509 million. The effective tax rate was 133.0% and 160.1% for the nine months ended September 30, 2012, and 2011, respectively.

For the nine months ended September 30, 2012, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of ITCs from the Company's Agua Caliente solar project in Arizona and the PTCs generated from certain Texas wind facilities.

For the nine months ended September 30, 2011, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to a benefit of $633 million resulting from the resolution of the federal tax audit. The benefit is predominantly due to the recognition of previously uncertain tax benefits that were effectively settled upon audit examination for years 2004 through 2006 and that were mainly composed of net operating losses of $536 million which has been classified as capital loss carryforwards for financial statement purposes.

Liquidity and Capital Resources

Liquidity Position

As of September 30, 2012, and December 31, 2011, NRG's liquidity, excluding collateral received, was approximately $3.0 billion and $2.1 billion, respectively, comprised of the following:

(In millions)	September 30, 2012	December 31, 2011
Cash and cash equivalents	$ 1,610	$ 1,105
Funds deposited by counterparties	76	