NRG ENERGY, INC.
Form 10-Q
November 03, 2011

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, 2011

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.
Yes x No o

As of October 31, 2011, there were 229,967,461 shares of common stock outstanding, par value $0.01 per share.

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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 the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, or Securities Act, and Section 21E of the 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 Energy, Inc.'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 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, 2010, including 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 2011 Senior Credit Facility, and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;
- NRG's ability to implement its RepoweringNRG strategy of developing and building new power generation facilities, including new wind and solar projects;
- NRG's ability to implement its econrg strategy of finding ways to meet the challenges of climate change, clean air and protecting natural resources while taking advantage of business opportunities;
- NRG's ability to achieve its strategy of regularly returning capital to shareholders;
- 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; and
- NRG's ability to develop and maintain successful partnering relationships.

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:

2010 Form 10-K	NRG’s Annual Report on Form 10-K for the year ended December 31, 2010
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 new senior secured facility, comprised of a $1.6 billion term loan facility and a $2.3 billion revolving credit facility, which replaces the Senior Credit Facility
2011 Term Loan Facility	The Company's $1.6 billion term loan facility due 2018, a component of the 2011 Senior Credit Facility
316(b) Rule	A section of the Clean Water Act regulating cooling water intake structures
ASR Agreement	Accelerated Share Repurchase Agreement
Baseload capacity	Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CATR	Clean Air Transport Rule
Capital Allocation Plan	Share repurchase program
Capital Allocation Program	NRG's plan of allocating capital between debt reduction, reinvestment in the business, and share repurchases through the Capital Allocation Plan
C&I	Commercial, industrial and governmental/institutional
CFTC	U.S. Commodity Futures Trading Commission
CPS	CPS Energy
CSAPR	Cross-State Air Pollution Rule
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
FFB	Federal Financing Bank

Funded Letter of Credit Facility	Prior to July 1, 2011, NRG's $1.3 billion term loan-backed fully funded senior secured letter of credit facility, of which $500 million would have matured on February 1, 2013, and $800 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 Funded Letter of Credit Facility, with the 2011 Senior Credit Facility.
GHG	Greenhouse Gases
Green Mountain Energy	Green Mountain Energy Company
GWh	Gigawatt hour
ISO	Independent System Operator, also referred to as Regional Transmission Organizations, or RTO
ISO-NE	ISO New England Inc.
LFRM	Locational Forward Reserve Market
LIBOR	London Inter-Bank Offer Rate
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
Mass	Residential and small business
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
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

RepoweringNRG	NRG's program designed to develop, finance, construct and operate new, highly efficient, environmentally responsible capacity
Revolving Credit Facility	Prior to July 1, 2011, NRG's $925 million senior secured revolving credit facility, which would have matured on August 31, 2015, and was a component of NRG's Senior Credit Facility. On July 1, 2011, NRG replaced the Senior Credit Facility, including the Revolving Credit Facility, with the 2011 Senior Credit Facility.
SEC	United States Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
Senior Credit Facility	Prior to July 1, 2011, NRG's senior secured facility, which was comprised of a Term Loan Facility, a $925 million Revolving Credit Facility and a $1.3 billion Funded Letter of Credit Facility. On July 1, 2011, NRG replaced the Senior Credit Facility with the 2011 Senior Credit Facility.
Senior Notes	The Company's $6.1 billion outstanding unsecured senior notes, consisting of $1.1 billion 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 and $1.2 billion of 7.875% senior notes due 2021
SO_2	Sulfur dioxide
STP	South Texas Project — nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest
STPNOC	South Texas Project Nuclear Operating Company
TANE	Toshiba America Nuclear Energy Corporation
TANE Facility	NINA's $500 million credit facility with TANE which matures on February 24, 2012
TEPCO	The Tokyo Electric Power Company of Japan, Inc.
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	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
U.S. GAAP	Accounting principles generally accepted in the United States

VaR	Value at Risk

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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)	2011	2010	2011	2010
Operating Revenues				
Total operating revenues	$2,674	$2,685	$6,947	$7,033
Operating Costs and Expenses				
Cost of operations	2,053	1,835	4,985	4,803
Depreciation and amortization	238	210	665	620
Impairment charge on emission allowances	160	—	160	—
Selling, general and administrative	169	172	479	441
Development costs	11	14	32	36
Total operating costs and expenses	2,631	2,231	6,321	5,900
Gain on sale of assets	—	—	—	23
Operating Income	43	454	626	1,156
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	16	16	26	41
Impairment charge on investment	(3)	—	(495)	—
Other income, net	5	11	13	34
Loss on debt extinguishment	(32)	(1)	(175)	(2)
Interest expense	(164)	(168)	(504)	(467)
Total other expense	(178)	(142)	(1,135)	(394)
(Loss)/Income Before Income Taxes	(135)	312	(509)	762
Income tax (benefit)/expense	(80)	89	(815)	271
Net (Loss)/Income	(55)	223	306	491
Less: Net loss attributable to noncontrolling interest	—	—	—	(1)
Net (Loss)/Income Attributable to NRG Energy, Inc.	(55)	223	306	492
Dividends for preferred shares	2	2	7	7
(Loss)/Income Available for Common Stockholders	$(57)	$221	$299	$485
(Loss)/Earnings Per Share Attributable to NRG Energy, Inc. Common Stockholders				
Weighted average number of common shares outstanding — basic	240	252	243	254
Net (loss)/income per weighted average common share — basic	$(0.24)	$0.88	$1.23	$1.91
Weighted average number of common shares outstanding — diluted	240	253	245	255
Net (loss)/income per weighted average common share — diluted	$(0.24)	$0.87	$1.22	$1.90

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except shares)	September 30, 2011 (unaudited)	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	$1,127	$2,951
Funds deposited by counterparties	259	408
Restricted cash	441	8
Accounts receivable — trade, less allowance for doubtful accounts of $33 and $21	1,042	734
Inventory	320	453
Derivative instruments	2,588	1,964
Cash collateral paid in support of energy risk management activities	316	323
Prepayments and other current assets	245	296
Total current assets	6,338	7,137
Property, plant and equipment, net of accumulated depreciation of $4,371 and $3,796	12,843	12,517
Other Assets		
Equity investments in affiliates	576	536
Note receivable — affiliate and capital leases, less current portion	327	384
Goodwill	1,859	1,868
Intangible assets, net of accumulated amortization of $1,345 and $1,064	1,561	1,776
Nuclear decommissioning trust fund	399	412
Derivative instruments	533	758
Restricted cash supporting funded letter of credit facility	—	1,300
Other non-current assets	324	208
Total other assets	5,579	7,242
Total Assets	$24,760	$26,896
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$81	$463
Accounts payable	974	783
Derivative instruments	2,089	1,685
Deferred income taxes	65	108
Cash collateral received in support of energy risk management activities	259	408
Accrued expenses and other current liabilities	527	773
Total current liabilities	3,995	4,220
Other Liabilities		
Long-term debt and capital leases	9,208	8,748
Funded letter of credit	—	1,300
Nuclear decommissioning reserve	331	317
Nuclear decommissioning trust liability	237	272
Deferred income taxes	1,588	1,989
Derivative instruments	408	365
Out-of-market commodity contracts	191	223
Other non-current liabilities	622	1,142
Total non-current liabilities	12,585	14,356
Total Liabilities	16,580	18,576

3.625% convertible perpetual preferred stock (at liquidation value, net of issuance costs)	248	248
Commitments and Contingencies		
Stockholders’ Equity		
Common stock	3	3
Additional paid-in capital	5,348	5,323
Retained earnings	4,099	3,800
Less treasury stock, at cost — 65,568,119 and 56,808,672 shares, respectively	(1,881)	(1,503)
Accumulated other comprehensive income	201	432
Noncontrolling interest	162	17
Total Stockholders’ Equity	7,932	8,072
Total Liabilities and Stockholders’ Equity	$24,760	$26,896

See notes to condensed consolidated financial statements.

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

Nine months ended September 30,	2011	2010
Cash Flows from Operating Activities		
Net income	$306	$491
Adjustments to reconcile net income to net cash provided by operating activities:		
Distributions and equity in earnings of unconsolidated affiliates	8	(19)
Depreciation and amortization	665	620
Provision for bad debts	41	46
Amortization of nuclear fuel	31	30
Amortization of financing costs and debt discount/premiums	25	23
Loss on debt extinguishment	58	—
Amortization of intangibles and out-of-market commodity contracts	118	(17)
Changes in deferred income taxes and liability for uncertain tax benefits	(829)	272
Changes in nuclear decommissioning trust liability	20	26
Changes in derivative instruments	(201)	(48)
Changes in collateral deposits supporting energy risk management activities	7	(116)
Impairment charge on investment	481	—
Impairment charge on emission allowances	160	—
Cash used by changes in other working capital	(222)	(167)
Net Cash Provided by Operating Activities	668	1,141
Cash Flows from Investing Activities		
Acquisitions of businesses, net of cash acquired	(352)	(142)
Capital expenditures	(1,355)	(490)
Increase in restricted cash, net	(92)	(17)
Increase in restricted cash to support equity requirements for U.S. DOE funded projects	(316)	—
Decrease in notes receivable	27	28
Purchases of emission allowances	(27)	(56)
Proceeds from sale of emission allowances	6	14
Investments in nuclear decommissioning trust fund securities	(314)	(245)
Proceeds from sales of nuclear decommissioning trust fund securities	294	219
Proceeds from renewable energy grants	—	102
Proceeds from sale of assets	14	30
Investments in unconsolidated affiliates	(17)	—
Other	(29)	(13)
Net Cash Used by Investing Activities	(2,161)	(570)
Cash Flows from Financing Activities		
Payment of dividends to preferred stockholders	(7)	(7)
Payment for treasury stock	(378)	(180)
Net (payments for)/receipts from settlement of acquired derivatives that include financing elements	(61)	58
Installment proceeds from sale of noncontrolling interest in subsidiary	—	50
Proceeds from issuance of long-term debt	5,710	1,252
Proceeds from issuance of term loan for funded letter of credit facility	—	1,300
Decrease/(increase) in restricted cash supporting funded letter of credit	1,300	(1,301)
Payment for settlement of funded letter of credit facility	(1,300)	—

Proceeds from issuance of common stock	2	2
Payment of debt issuance costs	(149)	(70)
Payments for short and long-term debt	(5,450)	(529)
Net Cash (Used)/Provided by Financing Activities	(333)	575
Effect of exchange rate changes on cash and cash equivalents	2	(3)
Net (Decrease)/Increase in Cash and Cash Equivalents	(1,824)	1,143
Cash and Cash Equivalents at Beginning of Period	2,951	2,304
Cash and Cash Equivalents at End of Period	$1,127	$3,447

See 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 with a significant presence in major competitive power markets in the United States. NRG is engaged in: the ownership, development, construction and operation of power generation facilities; the transacting in and trading of fuel and transportation services; the trading of energy, capacity and related products in the United States and select international markets; and the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through its retail businesses, Reliant Energy, Green Mountain Energy, and Energy Plus.

The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with the 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, 2010, or 2010 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, 2011, the results of operations for the three and nine months ended September 30, 2011, and 2010, and cash flows for the nine months ended September 30, 2011, and 2010.

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 $217 million which were accrued and unpaid at September 30, 2011.

Recent Accounting Developments

ASU No. 2011-08 — On September 15, 2011, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2011-08, Intangibles — Goodwill and Other (Topic 350) - Testing Goodwill for Impairment, or ASU 2011-08. The objective of ASU 2011-08 is to simplify how entities test goodwill for impairment. The amendments in ASU 2011-08 permit an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in Topic 350. The more-likely-than-not threshold is defined as having a likelihood of more than 50 percent. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed in fiscal years beginning after December 15, 2011. Early adoption is permitted. The Company will evaluate whether it will early adopt ASU 2011-08 for its annual impairment analysis in the fourth quarter 2011, and therefore has not yet determined whether there will be any impact on its results of operations, financial position or cash flows.

Note 3 — Comprehensive (Loss)/Income

The following table summarizes the components of the Company's comprehensive (loss)/income, net of tax:

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2011	2010	2011	2010
Net (loss)/income	$(55)	$223	$306	$491
Changes in derivative instruments	(76)	59	(225)	162
Foreign currency translation adjustment	(27)	36	(5)	(6)
Unrealized loss on available-for-sale securities	(1)	—	(1)	(1)
Other comprehensive (loss)/income	(104)	95	(231)	155
Less: Comprehensive loss attributable to noncontrolling interest	$—	$—	$—	$(1)
Comprehensive (loss)/income attributable to NRG Energy, Inc.	$(159)	$318	$75	$647

The following table summarizes the changes in the Company's accumulated other comprehensive income, or OCI, net of tax:

(In millions)	
Accumulated other comprehensive income as of December 31, 2010	$432
Changes in derivative instruments	(225)
Foreign currency translation adjustment	(5)
Unrealized loss on available-for-sale securities	$(1)
Accumulated other comprehensive income as of September 30, 2011	$201

Note 4 — Business Acquisitions and Dispositions

The Company's acquisitions that are considered business combinations are accounted for under the acquisition method of accounting in accordance with Accounting Standards Codification, or ASC, 805, Business Combinations, 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.

2011 Acquisitions

Energy Plus — On September 30, 2011, NRG acquired Energy Plus Holdings LLC, or Energy Plus, for $193 million in cash, net of $5 million cash acquired, funded from cash on hand. Energy Plus is a retail electricity provider with 180,000 customers, a Northeast concentration and a unique sales channel involving exclusive loyalty and affinity program partnerships. Energy Plus will be run as a separate retail business within NRG. The initial accounting for this business combination is not complete because the evaluations necessary to assess the fair values of certain net assets acquired to be recognized are still in process, and therefore the purchase price has been preliminarily allocated to intangible assets as of September 30, 2011.

Solar Acquisitions

During the nine months ended September 30, 2011, NRG acquired stakes in three solar facilities for approximately $165 million in cash consideration, as part of the Company's initiative to capture opportunities for future growth in renewables. In addition, NRG committed to contribute additional amounts into the projects, comprised of $291 million in restricted cash and $934 million in letters of credit as of September 30, 2011. The Company may increase its letters of credit to replace the restricted cash at its discretion. In addition, the projects had $49 million in restricted cash for various agreements. NRG's minority partners had additional equity commitments of $96 million as of September 30, 2011.

The purchase price for these acquisitions, considered business combinations, was provisionally allocated as follows, using a cost approach while the Company is in the process of performing its fair value assessments:

(In millions)	
Assets	
Restricted cash	$25
Property, plant and equipment	575
Intangible assets	48
Other current and non-current assets	39
Total assets	$687
Liabilities	
Accrued expenses	$364
Long-term debt	4
Total liabilities	368
Less: Non-controlling interest (Ivanpah)	154
Net assets acquired	$165

As required by ASC 820, Fair Value Measurement., the Company is in the process of determining the provisional fair values of the property, plant and equipment and the intangible assets at the acquisition date, and expects to have these provisional fair values determined by the end of 2011.

The acquisitions of these three solar facilities are further described below:

California Valley Solar Ranch — On September 30, 2011, NRG Solar LLC, a wholly-owned subsidiary of NRG, acquired 100% of the 250 MW California Valley Solar Ranch project, or CVSR, in eastern San Luis Obispo County, California. Operations are expected to commence in phases beginning in the first quarter of 2012 through the fourth quarter of 2013. Power generated from CVSR will be sold to Pacific Gas and Electric under a 25 year Power Purchase Agreement, or PPA. In connection with the acquisition, High Plains Ranch II, LLC, a wholly-owned subsidiary of NRG, entered into the California Valley Solar Ranch Financing Agreement with the Federal Financing Bank, or FFB, which is guaranteed by the United States Department of Energy, or U.S. DOE, to borrow up to $1.2 billion to fund the costs of constructing this solar facility, or the CVSR Financing Agreement. The terms of the borrowing, which are non-recourse to NRG, are described further in Note 9, Long-Term Debt.

Agua Caliente — On August 5, 2011, NRG, through its wholly-owned subsidiary, NRG Solar PV LLC, acquired 100% of the 290 MW Agua Caliente solar project, or Agua Caliente, in Yuma, AZ. Operations are scheduled to commence in phases beginning in the third quarter of 2012 through the first quarter of 2014. Power generated from Agua Caliente will be sold to Pacific Gas and Electric under a 25 year PPA. In connection with the acquisition, Agua Caliente Solar, LLC, a wholly-owned subsidiary of NRG, entered into the Agua Caliente Financing Agreement with the FFB, which is guaranteed by the U.S. DOE, to borrow up to $967 million to fund the construction of this solar facility, or the Agua Caliente Financing Agreement. The terms of the borrowings, which are non-recourse to NRG, are described further in Note 9, Long-Term Debt.

Ivanpah — On April 5, 2011, NRG acquired a 50.1% stake in the 392 MW Ivanpah Solar Electric Generation System, or Ivanpah, from BrightSource Energy, Inc., or BSE. Ivanpah is composed of three separate facilities - Ivanpah 1 (126 MW), Ivanpah 2 (133 MW), and Ivanpah 3 (133 MW), all of which are expected to be fully operational by the end of 2013. Power generated from Ivanpah will be sold to Southern California Edison and Pacific Gas and Electric, under multiple 20 to 25 year PPAs. The non-controlling interest represents the fair value of the capital contributions from the minority investors in Ivanpah. Ivanpah has entered into the Ivanpah Credit Agreement with the FFB, which is guaranteed by the U.S. DOE, to borrow up to $1.6 billion to fund the construction of this solar facility, or the Ivanpah Credit Agreement. The terms of the borrowings, which are non-recourse to NRG, are described further in Note 9, Long-Term Debt.

2010 Acquisitions

The Company made several acquisitions in 2010, which were recorded as business combinations under ASC 805. Those acquisitions for which purchase accounting was not finalized as of December 31, 2010, are briefly summarized below. See Note 3, Business Acquisitions and Note 12, Debt and Capital Leases, in the Company's 2010 Form 10-K for additional information related to these acquisitions.

Green Mountain Energy — On November 5, 2010, NRG acquired Green Mountain Energy for $357 million in cash, net of $75 million cash acquired, funded from cash on hand. The identifiable assets acquired and liabilities assumed were provisionally recorded at their estimated fair values on the acquisition date. The accounting for the Green Mountain Energy acquisition was completed as of September 30, 2011, at which point the provisional fair values became final with no material changes.

Cottonwood — On November 15, 2010, NRG acquired the Cottonwood Generating Station, or Cottonwood, a 1,265 MW combined cycle natural gas plant in the Entergy zone of east Texas for $507 million in cash, funded from cash on hand. The purchase price was primarily allocated to fixed assets acquired, which were recorded at provisional fair value on the acquisition date. The accounting for the Cottonwood acquisition was completed as of March 31, 2011, at which point the provisional fair values became final with no material changes.

2010 Disposition

Padoma — On January 11, 2010, NRG sold its terrestrial wind development company, Padoma Wind Power LLC, or Padoma, to Enel North America, Inc. NRG recognized a gain on the sale of Padoma of $23 million, which was recorded as a component of operating income in the statement of operations during the nine months ended September 30, 2010.

Note 5 — Nuclear Innovation North America LLC Developments, Including Impairment Charge

Nuclear Innovation North America LLC, or NINA, which is majority-owned by NRG, was established in May 2008 to focus on marketing, siting, developing, financing and investing in new advanced design nuclear projects in select markets across North America, including the planned South Texas Project Units 3 and 4, or STP 3 & 4, Project. Toshiba America Nuclear Energy Corporation, or TANE, a wholly-owned subsidiary of Toshiba Corporation, is the minority owner of NINA. NINA is a bankruptcy remote entity under NRG's corporate structure and designated as an Excluded Project Subsidiary under NRG's 2011 Senior Credit Facility and senior unsecured notes, which require that NRG not be obligated to contribute any capital to service NINA's debt or fund the repayment of any NINA debt in the event of a default. Furthermore, NRG is not required to continue the funding of NINA and any capital provided to NINA by any other equity partner could result in the dilution of NRG's equity interest.

On March 11, 2011, Japan was hit by a devastating earthquake and tsunami which, in turn, triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station owned by The Tokyo Electric Power Company of Japan, Inc., or TEPCO. The nuclear incident in Japan introduced multiple and substantial uncertainties around new nuclear development in the United States and the availability of debt and equity financing to NINA. Consequently, NINA announced, on March 21, 2011, that it was reducing the scope of development at the STP 3 & 4 expansion to allow time for the U.S. Nuclear Regulatory Commission, or NRC, and other nuclear stakeholders to assess the impacts from the events in Japan. NINA suspended indefinitely all detailed engineering work and other pre-construction activities and, as a result, dramatically reduced the project workforce. The decision to reduce the scope of activities was made jointly by NINA, NRG and Toshiba. Further, on April 19, 2011, NRG announced that, while it will cooperate with and support its current partners and any prospective future partners in attempting to develop STP 3 & 4 successfully, NRG was withdrawing from further financial participation in NINA's development of STP 3 & 4. NINA, going forward, will be focused solely on securing a combined operating license from the NRC and on obtaining the loan guarantee from the U.S. DOE, two items that are essential to the success of any future project development. TANE agreed, for the time being, to assume responsibility for NINA's ongoing costs associated with continuation of the licensing process.

Due to the events described above, NRG evaluated its investment in NINA for impairment. As part of this process, NRG evaluated the contractual rights and economic interests held by the various stakeholders in NINA, and concluded that while it continues to hold majority legal ownership, NRG ceased to have a controlling financial interest in NINA at the end of the first quarter of 2011. Consequently, NRG deconsolidated NINA as of March 31, 2011, in accordance with ASC 810, Consolidation, or ASC 810. This resulted in the removal of the following amounts from NRG's consolidated balance sheet: $930 million of construction in progress; $154 million of accounts payable and accrued expenses; $297 million of long-term debt; $17 million of non-controlling interest; and $19 million of other assets and liabilities. Furthermore, NRG assessed the impact of the diminished prospects for the STP 3 & 4 project on the fair value of NINA's assets relative to NINA's existing liabilities as well as NINA's potential contingent liabilities. Based on this assessment, the Company concluded it was remote that NRG would recover any portion of the carrying amount of its equity investment in NINA and, consequently, recorded an impairment charge of $481 million as of March 31, 2011 for the full amount of its investment. In concurrence with the substantial reduction in NINA's project workforce, and to support NINA's reduced scope of work, NRG contributed approximately $11 million from the second quarter of 2011 and $3 million from the third quarter of 2011, bringing the total impairment charge to $495 million for the nine months ended September 30, 2011. NRG expects to incur additional one-time costs, related to contributions to NINA, of up to $6 million, bringing these total expected costs to $20 million. These additional contributions are expensed as incurred to "Impairment charge on investment." This impairment charge included net assets contributed from all of NINA's equity investors, both NRG and TANE, which the Company previously consolidated.

As part of a March 1, 2010, settlement of litigation with CPS Energy, or CPS, NRG had agreed to pay $80 million to CPS, subject to the U.S. DOE's approval of a fully executed term sheet for a conditional U.S. DOE loan guarantee for STP 3 & 4. NRG also had agreed to donate an additional $10 million, unconditionally, over four years in annual payments of $2.5 million to the Residential Energy Assistance Partnership, or REAP, in San Antonio. Payments of $5 million were made to REAP through March 31, 2011. As a result of the events stemming from the nuclear incident in Japan, the Company no longer believes it probable that the conditional U.S. DOE loan guarantee will be received or accepted. Therefore, as of March 31, 2011, the Company reversed the $80 million contingent liability to CPS previously recorded within other current liabilities, along with the $80 million of associated amounts capitalized to construction in progress within property, plant and equipment. At September 30, 2011, $5 million in liabilities remains on the condensed consolidated balance sheet for the obligations to REAP.

Note 6 — Fair Value of Financial Instruments

The estimated carrying values and fair values of NRG's recorded financial instruments are as follows:

	Carrying Amount		Fair Value	
	September 30, 2011	December 31, 2010	September 30, 2011	December 31, 2010
	(In millions)			
Assets:				
Cash and cash equivalents	$1,127	$ 2,951	$1,127	$ 2,951
Funds deposited by counterparties	259	408	259	408
Restricted cash	441	8	441	8
Cash collateral paid in support of energy risk management activities	316	323	316	323
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	8	8	8	8
Marketable equity securities	1	3	1	3
Trust fund investments	401	414	401	414
Notes receivable	131	177	136	190
Derivative assets	3,121	2,722	3,121	2,722
Restricted cash supporting funded letter of credit facility	—	1,300	—	1,300
Liabilities:				
Long-term debt, including current portion	9,185	9,104	8,830	9,236
Funded letter of credit	—	1,300	—	1,295
Cash collateral received in support of energy risk management activities	259	408	259	408
Derivative liabilities	$2,497	$ 2,050	$2,497	$ 2,050

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Recurring Fair Value Measurements

The following table presents 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:

(In millions)	Fair Value			
As of September 30, 2011	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$1,127	$—	$—	$1,127
Funds deposited by counterparties	259	—	—	259
Restricted cash	441	—	—	441
Cash collateral paid in support of energy risk management activities	316	—	—	316
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	—	—	8	8
Marketable equity securities	1	—	—	1
Trust fund investments:				
Cash and cash equivalents	1	—	—	1
U.S. government and federal agency obligations	45	—	—	45
Federal agency mortgage-backed securities	—	66	—	66
Commercial mortgage-backed securities	—	7	—	7
Corporate debt securities	—	52	—	52
Marketable equity securities	193	—	33	226
Foreign government fixed income securities	—	4	—	4
Derivative assets:				
Commodity contracts	1,513	1,569	39	3,121
Total assets	$3,896	$1,698	$80	$5,674
Cash collateral received in support of energy risk management activities	$259	$—	$—	$259
Derivative liabilities:				
Commodity contracts	1,564	805	46	2,415
Interest rate contracts	—	82	—	82
Total liabilities	$1,823	$887	$46	$2,756

(In millions)	Fair Value			
As of December 31, 2010	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$2,951	$—	$—	$2,951
Funds deposited by counterparties	408	—	—	408
Restricted cash	8	—	—	8
Cash collateral paid in support of energy risk management activities	323	—	—	323
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	—	—	8	8
Marketable equity securities	3	—	—	3
Trust fund investments:				
Cash and cash equivalents	9	—	—	9
U.S. government and federal agency obligations	27	—	—	27
Federal agency mortgage-backed securities	—	57	—	57
Commercial mortgage-backed securities	—	11	—	11
Corporate debt securities	—	56	—	56
Marketable equity securities	213	—	39	252
Foreign government fixed income securities	—	2	—	2
Derivative assets:				
Commodity contracts	652	2,046	24	2,722
Restricted cash supporting funded letter of credit facility	1,300	—	—	1,300
Total assets	$5,894	$2,172	$71	$8,137
Cash collateral received in support of energy risk management activities	$408	$—	$—	$408
Derivative liabilities:				
Commodity contracts	660	1,251	51	1,962
Interest rate contracts	—	88	—	88
Total liabilities	$1,068	$1,339	$51	$2,458

There were no transfers during the three months and nine months ended September 30, 2011, and 2010, between Levels 1 and 2. The following tables reconcile, for the three months and nine months ended September 30, 2011, and 2010, 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, 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

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)							
	Three months ended September 30, 2010				Nine months ended September 30, 2010			
(In millions)	Debt Securities	Trust Fund Investments	Derivatives[a]	Total	Debt Securities	Trust Fund Investments	Derivatives[a]	Total
Beginning Balance	$10	$32	$(76)	$(34)	$9	$37	$(13)	$33
Total gains/(losses) - realized/unrealized:								
Included in earnings	3	—	18	21	3	—	(13)	(10)
Included in OCI	(1)	—	—	(1)	—	—	—	—
Included in nuclear decommissioning obligations	—	5	—	5	—	—	—	—
Purchases	—	—	(10)	(10)	—	—	(1)	(1)
Sales	(5)	—	—	(5)	(5)	—	—	(5)
Transfers into Level 3 [b]	—	—	31	31	—	—	(16)	(16)
Transfers out of Level 3 [b]	—	—	(8)	(8)	—	—	(2)	(2)
Ending balance as of September 30, 2010	$7	$37	$(45)	$(1)	$7	$37	$(45)	$(1)
The amount of the total gains for the period included in earnings attributable to the change in unrealized gains	$—	$—	$12	$12	$—	$—	$(24)	$(24)

relating to assets still held as of
September 30, 2010

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

(b) Transfers into/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 into/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.

In determining the fair value of NRG's Level 2 and 3 derivative contracts, NRG applies a credit reserve to reflect credit risk which is calculated based on credit default swaps. 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. As of September 30, 2010, the credit reserve resulted in a $6 million decrease in fair value which is composed of a $3 million loss in OCI and a $3 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 2010 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, 2011, counterparty credit exposure to a significant portion of the Company's counterparties was $1.2 billion and NRG held collateral (cash and letters of credit) against those positions of $262 million, resulting in a net exposure of $938 million. Counterparty credit exposure is discounted at the risk free rate. The following tables highlight the counterparty credit quality and the net counterparty credit exposure by industry sector. 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	55	%
Utilities, energy merchants, marketers and other	37	
Coal and emissions	5	
ISOs	3	
Total as of September 30, 2011	100	%

Category	Net Exposure [(a)] (% of Total)	
Investment grade	75	%
Non-Investment grade	1	
Non-rated [(b)]	24	
Total as of September 30, 2011	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 was $263 million. Approximately 73% of NRG's positions relating to this credit risk roll-off by the end of 2012. 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, solar PPA's, and a coal supply agreement. 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, 2011, credit risk exposure to these counterparties is approximately $686 million for the next five years. This amount excludes potential credit exposure 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. In the case of the coal supply agreement, NRG holds a lien against the underlying asset. These factors significantly reduce the risk of loss.

Retail Customer Credit Risk

NRG is exposed to credit risk through the Company's competitive electricity supply business, which serves retail customers. 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, 2011, the Company's retail customer credit exposure to C&I customers was diversified across many customers and various industries, with a significant portion of the exposure attributable to government entities.

NRG is also exposed to retail customer credit risk relating to its Mass customers, which may result in a write-off of bad debt. During 2011, the Company continued to experience improved customer payment behavior, but current economic conditions may affect the ability of the Company's customers to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

This footnote should be read in conjunction with the complete description under Note 5, Fair Value of Financial Instruments, to the Company's 2010 Form 10-K.

Note 7 — 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 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. 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 to the ratepayers 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, 2011				As of December 31, 2010			
(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	$1	$—	$—	—	$9	$—	$—	—
U.S. government and federal agency obligations	43	3	—	10	25	1	—	9
Federal agency mortgage-backed securities	66	3	—	21	57	2	—	24
Commercial mortgage-backed securities	7	—	—	28	11	—	—	29
Corporate debt securities	52	3	1	10	56	3	1	10
Marketable equity securities	226	91	2	—	252	117	1	—
Foreign government fixed income securities	4	—	—	6	2	—	—	8
Total	$399	$100	$3		$412	$123	$2	

The following tables summarize 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,	
(In millions)	2011	2010
Realized gains	$4	$4
Realized losses	3	2
Proceeds from sale of securities	294	219

Note 8 — 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 2010 Form 10-K.

Energy-Related Commodities

As of September 30, 2011, NRG had energy-related derivative financial instruments extending through December 2013, 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, 2011, NRG had interest rate derivative instruments on recourse debt extending through 2013 and on non-recourse debt extending through 2029, 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, 2011, and December 31, 2010. 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.

		Total Volume	
		September 30, 2011	December 31, 2010
Commodity	Units	(In millions)	
Emissions	Short Ton	(3)	—
Coal	Short Ton	40	34
Natural Gas	MMBtu	(8)	(175)
Oil	Barrel	—	1
Power	MWh	14	5
Capacity	MW/Day	—	(1)
Interest	Dollars	$1,265	$2,782

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Fair Value of Derivative Instruments

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

(In millions)	Fair Value Derivative Assets September 30, 2011	December 31, 2010	Derivative Liabilities September 30, 2011	December 31, 2010
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$—	$—	$—	$ 17
Interest rate contracts long-term	—	—	81	71
Commodity contracts current	203	392	—	2
Commodity contracts long-term	63	217	—	—
Total Derivatives Designated as Cash Flow or Fair Value Hedges	266	609	81	90
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Commodity contracts current	$2,385	$ 1,572	$2,089	$ 1,666
Commodity contracts long-term	470	541	326	294
Interest rate contracts long-term	—	—	1	—
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	2,855	2,113	2,416	1,960
Total Derivatives	$3,121	$ 2,722	$2,497	$ 2,050

Accumulated Other Comprehensive Income

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

	Three months ended September 30, 2011			Nine months ended September 30, 2011		
(In millions)	Energy Commodities	Interest Rate	Total	Energy Commodities	Interest Rate	Total
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

	Three months ended September 30, 2010			Nine months ended September 30, 2010		
(In millions)	Energy Commodities	Interest Rate	Total	Energy Commodities	Interest Rate	Total
Accumulated OCI beginning balance	$575	$(66)	$509	$461	$(55)	$406
Reclassified from accumulated OCI to income:						
- Due to realization of previously deferred amounts	(110)	—	(110)	(344)	—	(344)
Mark-to-market of cash flow hedge accounting contracts	173	(4)	169	521	(15)	506
Accumulated OCI ending balance, net of $342 tax	$638	$(70)	$568	$638	$(70)	$568
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $224 tax	$407	$(24)	$383	$407	$(24)	$383
Gains recognized in income from the ineffective portion of cash flow hedges	$14	$—	$14	$—	$2	$2

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 July 31, 2011, 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 2011. As a result, the Company de-designated its 2011 ERCOT cash flow hedges as of July 31, 2011 and prospectively marked these derivatives to market through the income statement.
The following table summarizes the amount of gain/(loss) resulting from fair value hedges reflected in interest income/(expense) for interest rate contracts:

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2011	2010	2011	2010
Derivative	$—	$(3)	$—	$—
Senior Notes (hedged item)	—	3	—	—

Impact of Derivative Instruments on the Statement of Operations

In accordance with ASC 815, unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedge derivatives and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activity on NRG's statement of operations. These gains are included within operating revenues and cost of operations.

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2011	2010	2011	2010
Unrealized mark-to-market results				
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$50	$(25)	$72	$(116)
Reversal of (gain)/loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	(15)	7	32	157
Reversal of loss positions acquired as part of the Green Mountain Energy acquisition as of November 5, 2010	4		28	—
Net unrealized (losses)/gains on open positions related to economic hedges	(7)	(60)	77	(129)
Gains on ineffectiveness associated with open positions treated as cash flow hedges	9	14	8	—
Total unrealized mark-to-market gains/(losses) for economic hedging activities	41	(64)	217	(88)
Reversal of previously recognized unrealized losses on settled positions related to trading activity	8	20	22	46
Net unrealized gains on open positions related to trading activity	—	9	22	32
Total unrealized mark-to-market gains for trading activity	8	29	44	78
Total unrealized gains/(losses)	$49	$(35)	$261	$(10)

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2011	2010	2011	2010
Revenue from operations — energy commodities	$89	$27	$193	$13
Cost of operations	(40)	(62)	68	(23)
Total impact to statement of operations	$49	$(35)	$261	$(10)

Reliant Energy's positions were acquired as of May 1, 2009, and valued using forward prices on that date. Green Mountain Energy's loss positions were acquired as of November 5, 2010, and valued using forward prices on that date. 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, 2011, the unrealized gain from open economic hedge positions is 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.

For the nine months ended September 30, 2010, the unrealized loss from open economic hedge positions is the result of a decrease in value of forward purchases of natural gas, electricity and fuel due to a decrease in forward power and gas prices. This was partially offset by an increase in the value of forward sales of natural gas and electricity.

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, 2011, was $36 million. The collateral required for contracts with credit rating contingent features was $36 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 $14 million as of September 30, 2011.

See Note 6, Fair Value of Financial Instruments, to this Form 10-Q for discussion regarding concentration of credit risk.

Note 9 — Long-Term Debt

This footnote should be read in conjunction with the complete description under Note 12, Debt and Capital Leases, to the Company's 2010 Form 10-K.

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

	September 30, 2011	December 31, 2010	Interest rate [(a)]
	(In millions, except rates)		
NRG Recourse Debt:			
Senior notes, due 2021	$1,200	$—	7.875
Senior notes, due 2020	1,100	1,100	8.250
Senior notes, due 2019	800	—	7.625
Senior notes, due 2019	691	690	8.500
Senior notes, due 2018	1,200	—	7.625
Senior notes, due 2017	1,090	1,100	7.375
Senior notes, due 2016	—	2,400	7.375
Senior notes, due 2014	—	1,205	7.250
Term loan facility, due 2018	1,592	—	L+3.00
Term loan facility, due 2013 - 2015 [(b)]	—	1,759	L+1.75 - L+3.25
Indian River Power LLC, tax-exempt bonds, due 2040	57	1	6.000
Indian River Power LLC, tax-exempt bonds, due 2045	126	66	5.375
Dunkirk Power LLC, tax-exempt bonds, due 2042	59	59	5.875
Subtotal NRG Recourse Debt	7,915	8,380	
NRG Non-Recourse Debt:			
NRG Peaker Finance Co. LLC, bonds, due 2019	$210	$206	L+1.07
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013, 2017, and 2025	153	163	5.95 - 7.31
Ivanpah Financing:			
Solar Partners I, due 2014 and 2033	210	—	1.126 - 3.991
Solar Partners II, due 2014 and 2038	221	—	1.116 - 4.195
Solar Partners VIII, due 2014 and 2038	195	—	1.381 - 4.256
Agua Caliente Solar, LLC	108	—	2.915 - 3.256
NRG Connecticut Peaking Development LLC, equity bridge loan facility, due 2011	—	61	L+2
NINA TANE facility	—	144	L+2
NINA Shaw facility	—	23	L+6
South Trent Wind LLC, financing agreement, due 2020	76	78	L+2.5
NRG Solar Blythe LLC, credit agreement, due 2028	28	29	L+2.5
NRG Roadrunner LLC	46	—	L+2.01
Other	23	20	various
Subtotal NRG Non-Recourse Debt	1,270	724	
Subtotal long-term debt	9,185	9,104	
Capital leases:			
Saale Energie GmbH, Schkopau capital lease, due 2021	104	107	
Subtotal	9,289	9,211	

Less current maturities	81	463	
Total long-term debt and capital leases	$9,208	$8,748	
Funded letter of credit [b]	$—	$1,300	L+1.75 - L+3.25

(a) L+ equals LIBOR plus x%.

(b) On July 1, 2011, the Term loan facility, due 2013-2015 and Funded letter of credit were repaid and replaced, as described below under Senior Credit Facility.

Issuance of 2018 Senior Notes

On January 26, 2011, NRG issued $1.2 billion aggregate principal amount at par of 7.625% Senior Notes due 2018, or 2018 Senior Notes. The 2018 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 2010 Form 10-K. The Indenture and the form of the note provide, among other things, that the 2018 Senior Notes will be senior unsecured obligations of NRG.

The net proceeds were used primarily to complete the tender offer of the 2014 Senior Notes. Interest is payable semi-annually beginning on July 15, 2011, until their maturity date of January 15, 2018.

Prior to maturity, NRG may redeem all or a portion of the 2018 Senior Notes at a redemption price equal to 100% of the principal amount of the notes redeemed plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1.00% of the principal amount of the note or (ii) the excess of the present value of the principal amount at maturity plus all required interest payments due on the note through the maturity date discounted at a Treasury rate plus 0.50%.

Redemption of 2014 Senior Notes

On January 26, 2011, the Company redeemed $945 million of the 2014 Senior Notes through a tender offer, at an early redemption percentage of 102.063%. An additional $2 million was tendered at a redemption percentage of 100.063% and the remaining $253 million of 2014 Senior Notes were called on February 25, 2011, at a redemption percentage of 101.813%. A $28 million loss on the extinguishment of the 2014 Senior Notes was recorded during the three months ended March 31, 2011, which primarily consisted of the premiums paid on the redemption and the write-off of previously deferred financing costs.

Issuance of 7.625% 2019 Senior Notes and 2021 Senior Notes

On May 24, 2011, NRG issued $800 million aggregate principal amount at par of 7.625% Senior Notes due 2019, or the 7.625% 2019 Senior Notes, and $1.2 billion aggregate principal amount at par of 7.875% Senior Notes due 2021, or the 2021 Senior Notes. The 7.625% 2019 Senior Notes and the 2021 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 Supplemental Indentures, which is discussed in Note 12, Debt and Capital Leases, in the Company's 2010 Form 10-K. The Indentures and the form of the notes provide, among other things, that the 7.625% 2019 Senior Notes and the 2021 Senior Notes will be senior unsecured obligations of NRG.

The net proceeds of $2 billion for both the 7.625% 2019 Senior Notes and the 2021 Senior Notes were used to complete the tender offer of the 2016 Senior Notes. Interest is payable semi-annually beginning on November 15, 2011, until their maturity dates of May 15, 2019, and May 15, 2021, respectively.

Prior to May 15, 2014, NRG may redeem up to 35% of the aggregate principal amount of the 7.625% 2019 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.625% of the principal amount. Prior to May 15, 2014, NRG may redeem all or a portion of the 7.625% 2019 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 103.813% of the note, plus interest payments due on the note from the date of redemption through May 15, 2014, discounted at a Treasury rate plus 0.50%. In addition, on or after May 15, 2014, 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
May 15, 2014 to May 14, 2015	103.813%
May 15, 2015 to May 14, 2016	101.906%
May 15, 2016 and thereafter	100.000%

Prior to May 15, 2016, NRG may redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.875% of the principal amount. Prior to May 15, 2016, NRG may redeem all or a portion of the 2021 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 103.938% of the note, plus interest payments due on the note from the date of redemption through May 15, 2016, discounted at a Treasury rate plus 0.50%. In addition, on or after May 15, 2016, 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
May 15, 2016 to May 14, 2017	103.938%
May 15, 2017 to May 14, 2018	102.625%
May 15, 2018 to May 14, 2019	101.313%
May 15, 2019 and thereafter	100.000%

In connection with the 7.625% 2019 Senior Notes and the 2021 Senior Notes, NRG entered into a registration payment arrangement. For the 7.625% 2019 Senior Notes and the 2021 Senior Notes, 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 7.625% 2019 Senior Notes or the 2021 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% per annum of the principal amount of the 7.625% 2019 Senior Notes or the 2021 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 2016 Senior Notes

On May 24, 2011, the Company redeemed $1.7 billion of the 2016 Senior Notes through a tender offer, at an early redemption percentage of 103.938%. An additional $0.4 million was tendered at a redemption percentage of 102.938% and the remaining $666 million of 2016 Senior Notes was called on June 23, 2011, at a redemption percentage of 103.688%. A $115 million loss on the extinguishment of the 2016 Senior Notes was recorded during the nine months ended September 30, 2011, which primarily consisted of the premiums paid on the redemption and the write-off of previously deferred financing costs.

Senior Credit Facility

Prepayment of Senior Credit Facility — In March 2011, NRG made a repayment of approximately $149 million to its first lien lenders under the Term Loan Facility. This payment resulted from the mandatory annual offer of a portion of NRG's excess cash flow (as defined in the Senior Credit Facility) for 2010.

2011 Senior Credit Facility — On July 1, 2011, NRG replaced its Senior Credit Facility, consisting of its Term Loan Facility, Revolving Credit Facility and Funded Letter of Credit Facility, with a new senior secured facility, or the 2011 Senior Credit Facility, which includes the following:

- A $2.3 billion revolving credit facility, or the 2011 Revolving Credit Facility, with a maturity date of July 1, 2016, which will pay interest on amounts drawn at a rate of LIBOR plus 2.75%. In connection with the issuance of the 2011 Revolving Credit Facility, the outstanding letters of credit were novated from the Funded Letter of Credit Facility to the 2011 Revolving Credit Facility. In addition, the related Funded Letter of Credit loan was repaid, the non-current restricted cash balance was returned to the lenders and the related balances were removed from NRG's balance sheet. A $13 million loss on extinguishment of the Revolving Credit Facility and Funded Letter of Credit Facility was recorded during the three months ended September 30, 2011, which consisted of the write-off of previously deferred financing costs. As of September 30, 2011, a total of $1.949 billion letters of credit were issued under the 2011 Revolving Credit Facility.

- A $1.6 billion term loan facility, or the 2011 Term Loan Facility, with a maturity date of July 1, 2018, which will pay interest at a rate of LIBOR plus 3%, with a LIBOR floor of 1%. The debt was issued at 99.75% of face value; the discount will be amortized to interest expense over the life of the loan. Repayments under the 2011Term Loan Facility will consist of 0.25% per quarter, with the remainder due at maturity. The proceeds of the new term loan facility were used to repay the existing Term Loan Facility balance outstanding. A $19 million loss on extinguishment of the Term Loan Facility was recorded during the three months ended September 30, 2011, which consisted of the write-off of previously deferred financing costs.

Indian River Power LLC Tax-Exempt Bonds

During the nine months ended September 30, 2011, the Company received additional proceeds of $60 million from the Delaware Economic Development Authority tax-exempt bond financing, and $56 million from the Sussex County, Delaware tax-exempt bond financing, bringing the total proceeds received as of September 30, 2011, to $126 million and $57 million, respectively.

Ivanpah Financing

On April 5, 2011, NRG acquired a majority interest in Ivanpah, as discussed in Note 4, Business Acquisitions and Dispositions. On April 5, 2011, Ivanpah entered into the Ivanpah Credit Agreement with the FFB to borrow up to $1.6 billion to finance the costs of constructing the Ivanpah solar facilities. Each phase of the project is governed by a separate financing agreement and is non recourse to both the other projects and to NRG. Funding requests are submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the Ivanpah Credit Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375% and are secured by all the assets of Ivanpah. Ivanpah intends to submit an application to the U.S. Department of Treasury for a cash grant; any proceeds received will be utilized to repay the borrowings that mature in 2014.

The following table reflects the borrowings under the Ivanpah Credit Agreement as of September 30, 2011:

	Maximum borrowings available under Ivanpah Credit Agreement	Amounts borrowed	Weighted average interest rate on amounts borrowed	
	(In millions, except rates)			
Solar Partners I, due June 27, 2014 [(a)]	$159	$153	1.678	%
Solar Partners I, due June 27, 2033	392	57	3.641	%
Solar Partners II, due February 27, 2014 [(a)]	132	129	1.609	%
Solar Partners II, due February 27, 2038	387	92	3.925	%
Solar Partners VIII, due October 27, 2014 [(a)]	117	111	1.996	%
Solar Partners VIII, due October 27, 2038	440	84	4.021	%
	$1,627	$626		

(a) The cash portion of the loan is fully drawn; additional amounts will be utilized for capitalized interest.

Roadrunner Financing

On May 25, 2011, NRG, through its wholly-owned subsidiary, NRG Roadrunner LLC, or Roadrunner, entered into a credit agreement with a bank, or the Roadrunner Financing Agreement, for a $47 million construction loan that converts to a term loan and a $21 million cash grant loan, both of which have an interest rate of LIBOR plus an applicable margin of 2.01%. The term loans have an interest rate of LIBOR plus an applicable margin which escalates 0.25% every five years and ranges from 2.01% at closing to 2.76% in year fifteen through maturity. The term loan, which is secured by all the assets of Roadrunner, matures on November 30, 2031, and amortizes based upon a predetermined schedule. The cash grant loan matures upon the earlier of the receipt of the cash grant or January 2012. The Roadrunner Financing Agreement also includes a letter of credit facility on behalf of Roadrunner of up to $5 million. Roadrunner pays an availability fee of 100% of the applicable margin on issued letters of credit. As of September 30, 2011, $46 million was outstanding under the construction loan and $2 million letters of credit in support of the PPA were issued.

Also related to the Roadrunner Financing Agreement, in April 2011, Roadrunner entered into a fixed for floating interest rate swap for 75% of the outstanding term loan amount, intended to hedge the risks associated with floating interest rates. Roadrunner will pay its counterparty the equivalent of a 4.313% fixed interest payment on a predetermined notional value, and Roadrunner will receive quarterly the equivalent of a floating interest payment based on a three month LIBOR calculated on the same notional value. All interest rate swap payments by Roadrunner 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 became effective September 30, 2011 and matures in December 2029, was $36 million and amortizes in proportion to the loan.

CVSR Financing

On September 30, 2011, NRG acquired CVSR, as discussed in Note 4, Business Acquisitions and Dispositions. In connection with the acquisition, High Plains Ranch II LLC, a wholly-owned subsidiary of NRG, entered into the CVSR Financing Agreement with the FFB, to borrow up to $1.2 billion to finance the costs of constructing this solar facility. The CVSR Financing Agreement, which matures in 2037, is non-recourse to NRG. Funding requests will be submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the CVSR Financing Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375%, and are secured by the assets of CVSR. As of September 30, 2011, no amounts were drawn under this agreement. CVSR intends to submit an application to the U.S. Department of Treasury for a cash grant; any proceeds received will be utilized to repay borrowings under the CVSR Financing Agreement.

Agua Caliente Financing

On August 5, 2011, NRG acquired Agua Caliente, as discussed in Note 4, Business Acquisitions and Dispositions. In connection with the acquisition, Agua Caliente Solar LLC, a wholly-owned subsidiary of NRG, entered into the Agua Caliente Financing Agreement with the FFB, to borrow up to $967 million to finance the costs of constructing this solar facility. The Agua Caliente Financing Agreement, which matures in 2037, is non-recourse to NRG. Funding requests will be submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the Agua Caliente Financing Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375%, and are secured by the assets of Agua Caliente. As of September 30, 2011, $108 million had been drawn under this agreement.

NRG West Holdings Credit Agreement

On August 23, 2011, NRG, through its wholly-owned subsidiary, NRG West Holdings LLC, or West Holdings, entered into a credit agreement with a group of lenders in respect to the El Segundo Energy Center, or the West Holdings Credit Agreement. The West Holdings Credit Agreement, which establishes a $540 million, two tranche construction loan facility with additional facilities for the issuance of letters of credit or working capital loans, is non-recourse to NRG and is secured by the assets of West Holdings.

The two tranche construction loan facility consists of the $480 million Tranche A Construction Facility, or the Tranche A Facility, and the $60 million Tranche B Construction Facility, or the Tranche B Facility. The Tranche A and Tranche B Facilities, which mature in August 2023, convert to a term loan and have an interest rate of LIBOR, plus an applicable margin which increases by 0.125% periodically from conversion through year eight for the Tranche A Facility and increases by 0.125% upon term conversion and on the third and sixth anniversary of the term conversion and by 0.250% on the eighth anniversary of the term conversion for the Tranche B Facility. The Tranche A and Tranche B Facilities amortize based upon a predetermined schedule over the term of the loan with the balance payable at maturity.

The West Holdings Credit Agreement also provides for the issuance of letters of credit and working capital loans to support the El Segundo Energy Center collateral needs. This includes letter of credit facilities on behalf of West Holdings of up to $90 million in support of the PPA, up to $48 million in support of the collateral agent, and a working capital facility which permits loans or the issuance of letters of credit of up to $10 million.

As of September 30, 2011, no amounts had been borrowed under the West Holdings Credit Agreement. On October 18, 2011, under the West Holdings Credit Agreement, West Holdings borrowed $106 million under the Tranche A Facility, issued a $30 million letter of credit in support of the PPA, and issued a $7 million letter of credit under the working capital facility.

Also related to the West Holdings Credit Agreement, on October 18, 2011, West Holdings entered into five fixed for floating interest rate swaps for, in aggregate, 75% of the outstanding construction and term loan amount of both the Tranche A Facility and Tranche B Facility. The swaps are intended to hedge the risks associated with floating interest rates. The swaps are forward starting and become effective on November 30, 2011. West Holdings will pay its counterparties quarterly the equivalent of a 2.4165% annualized fixed interest payment on a predetermined notional value, and West Holdings will receive quarterly the equivalent of a floating interest payment based on three month LIBOR calculated, in advance of the relevant interest period, on the same notional value. The original notional amount of the swaps, which mature on August 31, 2023, will be $135 million in aggregate and amortizes in proportion to the loan.

NRG CT Peaking

On June 29, 2011, NRG Connecticut Peaking Development LLC repaid the $61 million outstanding under the equity bridge loan facility, or EBL. The commitment was terminated and the collateral held under the EBL, including the letter of credit issued by NRG under the Funded Letter of Credit Facility, has been returned. The EBL was used to fund the majority of the equity portion of the GenConn Energy LLC investment.

Note 10 — Variable Interest Entities, or VIEs

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

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 $94 million as of September 30, 2011.

GenConn Energy LLC — Through its subsidiary, NRG Connecticut Peaking Development LLC, or NRG Connecticut, NRG owns a 50% interest in GenConn, a limited liability company formed to construct, own and operate two 200 MW peaking generation facilities in Connecticut at NRG's Devon and Middletown sites. The GenConn Devon facility reached commercial operation in 2010 and the GenConn Middleton facility reached commercial operations in June 2011. In July of 2011, NRG Connecticut's note receivable due from GenConn of $63 million, as discussed in Note 9, Capital Leases and Notes Receivable to the Company's 2010 Form 10-K, was converted into equity. NRG's maximum exposure to loss is limited to its equity investment, which was $134 million as of September 30, 2011.

Note 11 — Changes in Capital Structure

As of September 30, 2011, and December 31, 2010, 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, 2010	304,006,027	(56,808,672)	247,197,355
Shares issued under LTIP	168,295	—	168,295
Shares issued under ESPP	—	120,127	120,127
Capital Allocation Plan repurchases	—	(8,879,574)	(8,879,574)
Balance as of September 30, 2011	304,174,322	(65,568,119)	238,606,203

2011 Capital Allocation Plan

On February 22, 2011, the Company announced a plan to repurchase $180 million of common stock under the Company's 2011 Capital Allocation Plan. During the first quarter, the Company entered into an accelerated share repurchase agreement, or ASR Agreement, with a financial institution to repurchase a total of $130 million of NRG common stock, based on a volume weighted average price less a specified discount. Pursuant to the ASR Agreement, the Company received 6,229,574 shares of NRG common stock on April 29, 2011. On August 4 2011, the Company announced additional share repurchases of $250 million under the Capital Allocation Plan, bringing the total targeted share repurchases for 2011 to $430 million. During the month of August 2011, the Company purchased 2,650,000 shares of NRG common stock for approximately $58 million.

During the third quarter, the Company entered into a second accelerated share repurchase agreement, or the Second ASR Agreement, with a financial institution to repurchase a total of $190 million of NRG common stock, based on a volume weighted average price less a specified discount. The Second ASR Agreement was accounted for as a forward contract indexed to the Company's own stock and recorded as treasury stock during the third quarter. The share repurchases under the Second ASR Agreement were completed on October 6, 2011, and the Company received 8,646,224 shares of NRG common stock. The Company intends to complete its remaining $52 million of share repurchases by the end of 2011, subject to market prices, financial restrictions under the Company's debt facilities, and as permitted by securities laws.

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Note 12 — (Loss)/Earnings Per Share

Basic (loss)/earnings per common share is computed by dividing net (loss)/income 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. Shares borrowed under the Share Lending Agreement (see Note 15, Capital Structure — Share Lending Agreements in the Company's 2010 Form 10-K) were not treated as outstanding for earnings per share purposes.

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)	2011	2010	2011	2010
Basic (loss)/earnings per share attributable to NRG common stockholders				
Numerator:				
Net (loss)/income attributable to NRG Energy, Inc.	$(55)	$223	$306	$492
Preferred stock dividends	(2)	(2)	(7)	(7)
Net (loss)/income attributable to NRG Energy, Inc. available to common stockholders	$(57)	$221	$299	$485
Denominator:				
Weighted average number of common shares outstanding	240	252	243	254
Basic (loss)/earnings per share:				
Net (loss)/income attributable to NRG Energy, Inc.	$(0.24)	$0.88	$1.23	$1.91
Diluted (loss)/earnings per share attributable to NRG common stockholders				
Numerator:				
Net (loss)/income attributable to NRG Energy, Inc. available to common stockholders	$(57)	$221	$299	$485
Denominator:				
Weighted average number of common shares outstanding	240	252	243	254
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	—	1	2	1
Total dilutive shares	240	253	245	255
Diluted (loss)/earnings per share:				
Net (loss)/income attributable to NRG Energy, Inc.	$(0.24)	$0.87	$1.22	$1.90

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)	2011	2010	2011	2010
Equity compensation — NQSOs and PUs	7	6	7	6
Embedded derivative of 3.625% redeemable perpetual preferred stock	16	16	16	16

Total	23	22	23	22

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Note 13 — Segment Reporting

NRG's segment structure reflects core areas of operation which are primarily segregated based on the Company's wholesale power generation, Reliant Energy, thermal and chilled water business, and corporate activities. Within NRG's wholesale 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 International. The Company's corporate activities include solar and wind development, NINA activity, Green Mountain Energy, and Energy Plus. Intersegment supply sales between Texas, Reliant Energy, and Green Mountain Energy, are accounted for at market.

(In millions)		Wholesale Power Generation								
Three months ended September 30, 2011	Reliant Energy	Texas[(a)(b)]	Northeast	South Central	West	Internat-ional	Thermal	Corporate[(c)(d)]	Elimination	Total
Operating revenues	$1,637	$822	$299	$279	$49	$35	$37	$ 227	$(711)	$2,674
Depreciation and amortization	24	124	33	23	3	—	4	27	—	238
Equity in earnings/(losses) of unconsolidated affiliates	—	5	4	—	5	3	—	(1)	—	16
Income/(loss) before income taxes	65	(56)	10	23	24	8	3	(212)	—	(135)
Net income/(loss) attributable to NRG Energy, Inc.	$65	$(56)	$10	$23	$24	$6	$3	$ (130)	$—	$(55)
Total assets	$1,623	$12,834	$1,919	$1,279	$2,389	$676	$347	$ 17,774	$(14,081)	$24,760

(a) Includes inter-segment sales of $597 million to Reliant Energy and $110 million to Green Mountain Energy.
(b) Includes impairment charge on emission allowances of $160 million.
(c) Includes Green Mountain Energy results, and Energy Plus assets as of the September 30, 2011, date of acquisition.
(d) Includes impairment charges on investment of $3 million and loss on debt extinguishment of $32 million.

(In millions)		Wholesale Power Generation								
Three months ended September 30, 2010	Reliant Energy	Texas[(e)]	Northeast	South Central	West	Internat-ional	Thermal	Corporate	Elimination	Total
Operating revenues	$1,562	$1,040	$353	$166	$43	$30	$40	$(1)	$(548)	$2,685
Depreciation and amortization	32	124	29	17	2	—	3	3	—	210
	—	8	—	—	4	4	—	—	—	16

Equity in earnings of unconsolidated affiliates										
(Loss)/income before income taxes	(20)	439	23	8	20	10	3	(171)	—	312
Net (loss)/income attributable to NRG Energy, Inc.	$(20)	$439	$23	$8	$20	$7	$3	$(257)	$—	$223

(e) Includes inter-segment sales of $547 million to Reliant Energy.

(In millions)		Wholesale Power Generation								
Nine months ended September 30, 2011	Reliant Energy	Texas[a][b]	Northeast	South Central	West	Internat-ional	Thermal	Corporate[c][d]	Elimination	Total
Operating revenues	$3,906	$2,175	$771	$656	$129	$108	$109	$ 510	$(1,417)	$6,947
Depreciation and amortization	72	368	89	65	9	—	11	51	—	665
Equity in (losses)/earnings of unconsolidated affiliates	—	(1)	9	—	10	9	—	(1)	—	26
Income/(loss) before income taxes	368	154	(3)	49	49	26	6	(1,158)	—	(509)
Net income/(loss) attributable to NRG Energy, Inc.	$368	$154	$(3)	$49	$49	$20	$6	$ (337)	$—	$306

(a) Includes inter-segment sales of $1,230 million to Reliant Energy and $176 million to Green Mountain Energy.
(b) Includes impairment charge on emission allowances of $160 million.
(c) Includes Green Mountain Energy results.
(d) Includes impairment charges 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.

(In millions)		Wholesale Power Generation								
Nine months ended September 30, 2010	Reliant Energy	Texas[e]	Northeast	South Central	West	Internat-ional	Thermal	Corporate	Elimination	Total
Operating revenues	$4,020	$2,602	$837	$461	$110	$ 95	$103	$(3)	$(1,192)	$7,033
Depreciation and amortization	91	365	92	49	8	—	8	7	—	620
Equity in earnings/(losses) of unconsolidated affiliates	—	19	(1)	—	5	19	—	(1)	—	41
Income/(loss) before income taxes	69	971	73	8	34	51	5	(449)	—	762
Net loss attributable to non-controlling interest	—	(1)	—	—	—	—	—	—	—	(1)
Net income/(loss)attributable to NRG Energy, Inc.	$69	$972	$73	$8	$34	$ 36	$5	$(705)	$—	$492

(e) Includes inter-segment sales of $1,187 million to Reliant Energy.

Note 14 — 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)	2011	2010	2011	2010
Income tax (benefit)/expense	$(80)	$89	$(815)	$271
Effective tax rate	59.3 %	28.5 %	160.1 %	35.6 %

For the three and nine months ended September 30, 2011, NRG recorded an income tax benefit on pre-tax losses of $135 million and $509 million, respectively. For the three and nine months ended September 30, 2011, respectively, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to a reduction in the valuation allowance and 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 in June 2011 and that were mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes. For both the three and nine months ended September 30, 2010, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to a reduction in the valuation allowance resulting from the generation of capital gains partially offset by state and local income taxes.

Uncertain tax benefits

In the second quarter of 2011, the Company received the audit report effectively closing the Internal Revenue Service's audit examination for the years 2004 through 2006. The Company believes the matters addressed under audit are effectively settled in accordance with ASC 740 and recognized a benefit of $536 million to income tax expense during the 2011 second quarter. In August, the Company received the income tax refund for the years under examination.

As of September 30, 2011, a non-current tax liability of $55 million for uncertain tax benefits remains from positions taken on various state tax returns, including accrued interest. NRG has accrued interest and penalties related to these uncertain tax benefits of $2 million for the nine months ended September 30, 2011, and has accrued $10 million since adoption. The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense.

The Company continues to be under examination for various state jurisdictions for multiple years.

Tax Receivable and Payable

As of September 30, 2011, NRG recorded a current tax payable of $22 million that represents a tax liability due for domestic state taxes of $19 million, as well as foreign taxes payable of $3 million. In addition, as of September 30, 2011, NRG has a domestic tax receivable of $57 million, of which $45 million is related to property tax refunds as a result of the New York State Empire Zone program. In addition, we have recorded a $49 million non-current asset for Empire Zone credits generated in 2010 and 2011 that are being deferred pursuant to New York State law.

Note 15 — Benefit Plans and Other Postretirement Benefits

NRG sponsors and operates three defined benefit pension and other postretirement plans. In addition, NRG has a 44% undivided ownership interest in STP 1 & 2. South Texas Project Nuclear Operating Company, or STPNOC, which operates and maintains STP 1 & 2, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the South Texas Project plans, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations.

The total amount of employer contributions paid for the nine months ended September 30, 2011, including reimbursements to STPNOC, was $29 million. Relating to its sponsored plans as well as its 44% interest in STP 1 & 2, the Company recognized total net periodic benefit cost of $10 million and $29 million for the three and nine months ended September 30, 2011, respectively, and $9 million and $24 million for the three and nine months ended September 30, 2010, respectively.

Note 16 — Commitments and Contingencies

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, 2011, all hedges under the first liens were in-the-money for NRG on a counterparty aggregate basis.

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 Federal Energy Regulatory Commission, or 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 Public Utilities Commission of the State of California 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.

At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by the FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG's financial position, statement of operations, and statement of cash flows. 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 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.

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 Department of Justice 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 June 8, 2009, the parties filed a joint status report in the U.S. DOJ lawsuit setting forth their views of the case and proposing a trial schedule. While the district court entered a Joint Case Management Order on April 28, 2010, indicating the potential of a 2011 liability phase trial, no such trial date has been set.

On August 24, 2009, LaGen filed a motion to dismiss this lawsuit, and on September 25, 2009, the U.S. DOJ filed its opposition to the motion. Thereafter, on February 18, 2010, the Louisiana Department of Environmental Quality, or LDEQ, filed a motion to intervene in the above lawsuit and a complaint against LaGen for alleged violations of Louisiana's Prevention of Significant Deterioration, or PSD, regulations and Louisiana's Title V operating permit program. LDEQ seeks substantially similar relief to that requested by the U.S. DOJ. On February 19, 2010, the district court granted LDEQ's motion to intervene. On April 26, 2010, LaGen filed a motion to dismiss the LDEQ complaint. On July 21, 2010, the motions to dismiss the U.S. DOJ and LDEQ complaints were argued to the district court. On August 20, 2010, the parties submitted proposed findings of fact and conclusions of law, and both parties have submitted additional briefing on emerging jurisprudence from other jurisdictions touching on the issues at stake in the U.S. DOJ lawsuit. On February 4, 2011, LaGen filed motions for summary judgment requesting that the court dismiss all of the U.S. DOJ's claims. Also on February 4, 2011, the U.S. DOJ filed three motions for partial summary judgment. Additional summary judgment briefing was filed by the parties on April 4, 2011. On April 20, 2011, the district court ruled that certain of the liability phase deadlines were vacated until the court ruled on the summary judgment motions submitted by the parties. A status conference was held with the magistrate judge on August 5, 2011. On August 26, 2011, the magistrate judge entered an order delaying remedy phase discovery 90 days. On September 12, 2011, the court set certain motions for summary judgment for hearing on November 2, 2011, at which time the court heard oral argument. No decisions have been issued.

Excess Mitigation Credits

From January 2002 to April 2005, CenterPoint Energy applied excess mitigation credits, or EMCs, to its monthly charges to retail electric providers as ordered by the PUCT. The PUCT imposed these credits to facilitate the transition to competition in Texas, which had the effect of lowering the retail electric providers' monthly charges payable to CenterPoint Energy. As indicated in its Petition for Review filed with the Supreme Court of Texas on June 2, 2008, CenterPoint Energy has claimed that the portion of those EMCs credited to Reliant Energy Retail Services, LLC, or RERS, a retail electric provider and NRG subsidiary acquired from RRI Energy, Inc. (formerly Reliant Energy, Inc.), totaled $385 million for RERS's “Price to Beat” Customers. It is unclear what the actual number may be. “Price to Beat” was the rate RERS was required by state law to charge residential and small commercial customers that were transitioned to RERS from the incumbent integrated utility company commencing in 2002. In its original stranded cost case brought before the PUCT on March 31, 2004, CenterPoint Energy sought recovery of all EMCs that were credited to all retail electric providers, including RERS, and the PUCT ordered that relief in its Order on Rehearing in Docket No. 29526, on December 17, 2004. After an appeal to state district court, the court entered a final judgment on August 26, 2005, affirming the PUCT's order with regard to EMCs credited to RERS. Various parties filed appeals of that judgment, and on April 17, 2008, the Court of Appeals for the Third District reversed the lower court's decision ruling that CenterPoint Energy's stranded cost recovery should exclude only EMCs credited to RERS for its “Price to Beat” customers. On June 2, 2008, CenterPoint Energy's Petition for Review with the Supreme Court of Texas was accepted. Oral argument occurred on October 6, 2009, and on March 18, 2011, the Texas Supreme Court reversed the Court of Appeals, finding no basis for deducting EMCs credited to RERS. Motions for rehearing were filed on May 4, 2011. On June 10, 2011, the Texas Supreme Court denied all motions for rehearing, thereby ending the matter.

In November 2008, CenterPoint Energy and Reliant Energy Inc., or REI, on behalf of itself and affiliates including RERS, agreed to suspend unexpired deadlines, if any, related to limitations periods that might exist for possible claims against REI and its affiliates if CenterPoint Energy is ultimately not allowed to include in its stranded cost calculation those EMCs previously credited to RERS. The agreed upon suspension of unexpired deadlines ceased on August 29, 2011. NRG believes that any possible future CenterPoint Energy claim against RERS for EMCs credited to RERS would lack legal merit. No such claim has been filed.

Wise v. Energy Plus Holdings, LLC

On October 18, 2011, plaintiff filed a purported class action lawsuit on behalf of New York consumers against Energy Plus in the U.S. District Court for the Southern District of New York. Claiming statutory damages in excess of $5 million, the plaintiff alleges violations of New York business laws as well as unjust enrichment. Specifically, the plaintiff claims 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. Plaintiff seeks that this matter be: certified as a class action; treble damages; interest; costs; attorneys fees and any other relief that the court deems just and proper.

Note 17 — 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 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 FERC's acceptance of station power rules for the CAISO market, and remanded the case for further proceedings at FERC. On August 30, 2010, 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, 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, FERC issued an order denying rehearing. The Company, together with other generators, filed an appeal and briefing of the case is currently underway. On April 22, 2011, Southern California Edison Company filed with the California Public Utilities Commission, or 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 September 20, 2011, the CPUC issued a suspension letter, providing it up to 180 additional days to consider Southern California Edison's filing. 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 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' position. Constellation may ask the Court of Appeals to reconsider its decision or ask the Texas Supreme Court to hear the case.

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, FERC eliminated certain regional through-and-out transmission rates charged by transmission owners in the regional electric grids operated by the Midwest Independent Transmission Systems Operator, Inc. and PJM Interconnection, L.L.C., or PJM, respectively. In order to temporarily compensate the transmission owners for revenue lost as a result of the elimination of the through-and-out transmission rates, 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 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, FERC issued two orders. In its Order on Rehearing, 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, 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 RTOs and their respective transmission owners submit further compliance filings, which were filed on August 19, 2010. FERC has not yet ruled on those compliance filings.

With regard to the SECA charges that had been invoiced to Green Mountain Energy, 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 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.

Multiple requests for rehearing were filed from the Order on Initial Decision, and BP Energy sought rehearing of the Order on Rehearing. Several parties filed notices of appeal of the Order on Rehearing, which are being held in abeyance pending resolution of SECA-related matters still pending before FERC. On September 19, 2011, two entities — Quest Energy and Integrys Energy Services — filed a motion with the U.S. Court of Appeals for the D.C. Circuit objecting to FERC's request to continue holding the case in abeyance.
On September 30, 2011, 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. On October 3, 2011, Quest Energy and Integrys Energy Services moved to withdraw their pending motion, and the D.C. Circuit granted that request on October 6, 2011.

Note 18 — 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 laws have become increasingly stringent and NRG expects this trend to continue. The electric generation industry will face new requirements to address air emissions, climate change, combustion byproducts and water use. In general, future laws and regulations are expected to require the addition of emission controls or other environmental quality equipment or the imposition of certain restrictions on the operations of the Company's facilities. NRG expects that future liability under, or compliance with, environmental requirements 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 2011 through 2015 to meet NRG's environmental commitments will be approximately $721 million (of which $180 million will be financed through draws on the Indian River tax exempt facilities) and are primarily associated with controls on the Company's Big Cajun and Indian River facilities. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with current and proposed federal and state air quality rules and consent orders, as well as installation of Best Technology Available, or BTA, under the proposed 316(b) Rule. NRG continues to explore cost effective compliance alternatives. While this estimate reflects anticipated schedules and controls related to the proposed Mercury and Air Toxics Standards and the 316(b) Rule, 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. However, NRG believes it is positioned to meet more stringent requirements through its planned capital expenditures, existing controls, and the use of Powder River Basin coal.

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.

The U.S. EPA released the final Cross-State Air Pollution Rule, or CSAPR, on July 7, 2011, with additional proposed updates on October 6, 2011. CSAPR will replace CAIR and is designed to bring 27 states into attainment with PM 2.5 and ozone national ambient air quality standards, or NAAQS, reducing SO_2 and NO_x emissions from power plants. Under CSAPR, use of discounted Acid Rain SO_2 and CAIR NO_x allowances will be discontinued and replaced with completely distinct allowance programs. Acid Rain allowances will still be required on a 1:1 basis under the Acid Rain Program. Consequently, in the three months ended September 30, 2011, the Company recorded an impairment charge of $160 million 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.

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.

Pursuant to a consent order dated September 25, 2007, and amended July 21, 2010, between NRG and DNREC regarding the Indian River plant, NRG agreed to limit the emissions of NO_x and SO_2, and to mothball Units 1 and 2. Unit 1 was mothballed as planned on May 1, 2011.

South Central Region

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. Further discussion on this matter can be found in Note 16, Commitments and Contingencies — Louisiana Generating, LLC, to this Form 10-Q.

Note 19 — Condensed Consolidating Financial Information

As of September 30, 2011, the Company had outstanding $1.1 billion of 7.375% Senior Notes due 2017, $1.2 billion of 7.625% Senior Notes due 2018, $700 million of 8.50% Senior Notes due 2019, $800 million of 7.625% Senior Notes due 2019, $1.1 billion of 8.25% Senior Notes due 2020 and $1.2 billion of 7.875% Senior Notes due 2021. These notes are guaranteed by certain of NRG's current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of September 30, 2011:

Arthur Kill Power LLC	NRG Artesian Energy LLC	NRG Services Corporation
Astoria Gas Turbine Power LLC	NRG Arthur Kill Operations Inc.	NRG Simply Smart Solutions LLC
Cabrillo Power I LLC	NRG Astoria Gas Turbine Operations Inc.	NRG South Central Affiliate Services Inc.
Cabrillo Power II LLC	NRG Bayou Cove LLC	NRG South Central Generating LLC
Carbon Management Solutions LLC	NRG Cabrillo Power Operations Inc.	NRG South Central Operations Inc.
Clean Edge Energy LLC	NRG California Peaker Operations LLC	NRG South Texas LP
Conemaugh Power LLC	NRG Cedar Bayou Development Company, LLC	NRG Texas LLC
Connecticut Jet Power LLC	NRG Connecticut Affiliate Services Inc.	NRG Texas C&I Supply LLC
Cottonwood Development LLC	NRG Construction LLC	NRG Texas Holding Inc.
Cottonwood Energy Company LP	NRG Development Company Inc.	NRG Texas Power LLC
Cottonwood Generating Partners I LLC	NRG Devon Operations Inc.	NRG West Coast LLC
Cottonwood Generating Partners II LLC	NRG Dunkirk Operations, Inc.	NRG Western Affiliate Services Inc.
Cottonwood Generating Partners III LLC	NRG El Segundo Operations Inc.	O'Brien Cogeneration, Inc. II
Cottonwood Technology Partners LP	NRG Energy Labor Services LLC	ONSITE Energy, Inc.
Devon Power LLC	NRG Energy Services Group LLC	Oswego Harbor Power LLC
Dunkirk Power LLC	NRG Energy Services LLC	Pennywise Power LLC
Eastern Sierra Energy Company	NRG Generation Holdings Inc.	RE Retail Receivables LLC
El Segundo Power LLC	NRG Huntley Operations Inc.	Reliant Energy Northeast LLC
El Segundo Power II, LLC	NRG Ilion Limited Partnership	Reliant Energy Power Supply LLC
Elbow Creek Wind Project LLC	NRG Ilion LP LLC	Reliant Energy Retail Holdings LLC
Energy Protection Insurance Company	NRG International LLC	Reliant Energy Retail Services LLC
GCP Funding Company, LLC	NRG Maintenance Services LLC	Reliant Energy Texas Retail LLC
Green Mountain Energy Company	NRG Mextrans Inc.	RERH Holdings, LLC
Huntley Power LLC	NRG MidAtlantic Affiliate Services Inc.	Saguaro Power LLC
Indian River Operations Inc.	NRG Middletown Operations Inc.	Somerset Operations Inc.
Indian River Power LLC	NRG Montville Operations Inc.	Somerset Power LLC
Keystone Power LLC	NRG New Jersey Energy Sales LLC	Texas Genco Financing Corp.
Langford Wind Power, LLC	NRG New Roads Holdings LLC	Texas Genco GP, LLC
Louisiana Generating LLC	NRG North Central Operations Inc.	Texas Genco Holdings, Inc.
Meriden Gas Turbines LLC	NRG Northeast Affiliate Services Inc.	Texas Genco LP, LLC
Middletown Power LLC	NRG Norwalk Harbor Operations Inc.	Texas Genco Operating Services LLC

Montville Power LLC	NRG Operating Services, Inc.	Texas Genco Services, LP
NEO Corporation	NRG Oswego Harbor Power Operations Inc.	Vienna Operations Inc.
NEO Freehold-Gen LLC	NRG PacGen Inc.	Vienna Power LLC
NEO Power Services Inc.	NRG Power Marketing LLC	WCP (Generation) Holdings LLC
New Genco GP, LLC	NRG Retail LLC	West Coast Power LLC
Norwalk Power LLC	NRG Rockford Acquisition LLC	
NRG Affiliate Services Inc.	NRG Saguaro Operations Inc.	

The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries. 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, 2011

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
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 Income/(Expense)					
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.

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
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 emission 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 Income/(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 BALANCE SHEETS
September 30, 2011

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 16	$ 108	$ 1,003	$ —	$ 1,127
Funds deposited by counterparties	259	—	—	—	259
Restricted cash	57	322	62	—	441
Accounts receivable, net	995	47	—	—	1,042
Inventory	311	9	—	—	320
Derivative instruments	2,588	—	—	—	2,588
Cash collateral paid in support of energy risk management activities	316	—	—	—	316
Prepayments and other current assets	116	34	1,303	(1,208)	245
Total current assets	4,658	520	2,368	(1,208)	6,338
Net property, plant and equipment	10,545	2,254	61	(17)	12,843
Other Assets					
Investment in subsidiaries	220	481	12,978	(13,679)	—
Equity investments in affiliates	37	539	—	—	576
Notes receivable – affiliate and capital leases, less current portion	—	327	311	(311)	327
Goodwill	1,859	—	—	—	1,859
Intangible assets, net	1,284	84	231	(38)	1,561
Nuclear decommissioning trust fund	399	—	—	—	399
Derivative instruments	533	—	—	—	533
Other non-current assets	51	61	213	(1)	324
Total other assets	4,383	1,492	13,733	(14,029)	5,579
Total Assets	$ 19,586	$ 4,266	$ 16,162	$ (15,254)	$ 24,760
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 1,150	$ 65	$ 16	$ (1,150)	$ 81
Accounts payable	(6)	326	654	—	974
Derivative instruments	2,086	3	—	—	2,089
Deferred income taxes	504	(51)	(388)	—	65
Cash collateral received in support of energy risk management activities	259	—	—	—	259
Accrued expenses and other current liabilities	339	30	216	(58)	527
Total current liabilities	4,332	373	498	(1,208)	3,995
Other Liabilities					
Long-term debt and capital leases	242	1,620	7,657	(311)	9,208
Nuclear decommissioning reserve	331	—	—	—	331
Nuclear decommissioning trust liability	237	—	—	—	237
Deferred income taxes	1,441	272	(125)	—	1,588

Derivative instruments	326	52	30	—	408
Out-of-market commodity contracts	216	6	—	(31)	191
Other non-current liabilities	493	45	84	—	622
Total non-current liabilities	3,286	1,995	7,646	(342)	12,585
Total liabilities	7,618	2,368	8,144	(1,550)	16,580
3.625% Preferred Stock	—	—	248	—	248
Stockholders' Equity	11,968	1,898	7,770	(13,704)	7,932
Total Liabilities and Stockholders' Equity	$ 19,586	$ 4,266	$ 16,162	$ (15,254)	$ 24,760

(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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 185	$ 23	$ 306	$ (208)	$ 306
Adjustments to reconcile net income to net cash provided/(used) by operating activities:					
Distributions and equity in earnings 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
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	742	7	(222)
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 businesses, 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
Purchases of emission allowances	(27)	—	—	—	(27)
Proceeds from sale of emission allowances	6	—	—	—	6
Investments in nuclear decommissioning trust fund securities	(314)	—	—	—	(314)
Proceeds from sales of nuclear decommissioning trust fund securities	294	—	—	—	294
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)
Payments of intercompany dividends	(65)	(1,304)	—	1,369	—
Payment for treasury stock	—	—	(378)	—	(378)
Net payments to settle 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 facility	—		(1,300)	—	(1,300)
Proceeds from issuance of common stock	—	—	2	—	2
Payment of debt issuance 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.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended September 30, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 2,589	$ 101	$—	$ (5)	$ 2,685
Operating Costs and Expenses					
Cost of operations	1,775	65	—	(5)	1,835
Depreciation and amortization	198	9	3	—	210
Selling, general and administrative	99	5	68	—	172
Development costs	—	2	12	—	14
Total operating costs and expenses	2,072	81	83	(5)	2,231
Operating Income/(Loss)	517	20	(83)	—	454
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	8	—	365	(373)	—
Equity in earnings of unconsolidated affiliates	4	12	—	—	16
Other income, net	1	6	4	—	11
Loss on debt extinguishment	—	—	(1)	—	(1)
Interest expense	1	(14)	(155)	—	(168)
Total other income/(expense)	14	4	213	(373)	(142)
Income Before Income Taxes	531	24	130	(373)	312
Income tax expense/(benefit)	178	4	(93)	—	89
Net Income attributable to NRG Energy, Inc.	$ 353	$ 20	$223	$ (373)	$ 223

(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, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 6,782	$ 270	$—	$ (19)	$ 7,033
Operating Costs and Expenses					
Cost of operations	4,631	184	7	(19)	4,803
Depreciation and amortization	590	23	7	—	620
Selling, general and administrative	238	10	193	—	441
Development costs	—	8	28	—	36
Total operating costs and expenses	5,459	225	235	(19)	5,900
Gain on sale of assets	—	—	23	—	23
Operating Income/(Loss)	1,323	45	(212)	—	1,156
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	30	—	891	(921)	—
Equity in earnings of unconsolidated affiliates	5	36	—	—	41
Other income, net	4	23	7	—	34
Loss on debt extinguishment	—	(1)	(1)	—	(2)
Interest expense	(10)	(36)	(421)	—	(467)
Total other income/(expense)	29	22	476	(921)	(394)
Income Before Income Taxes	1,352	67	264	(921)	762
Income tax expense/(benefit)	479	20	(228)	—	271
Net Income	873	47	492	(921)	491
Less: Net loss attributable to noncontrolling interest	(1)	—	—	—	(1)
Net Income attributable to NRG Energy, Inc.	$ 874	$ 47	$492	$ (921)	$ 492

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 168	$ 111	$ 2,672	$ —	$ 2,951
Funds deposited by counterparties	408	—	—	—	408
Restricted cash	2	6	—	—	8
Accounts receivable-trade, net	693	38	3	—	734
Inventory	445	8	—	—	453
Derivative instruments	1,964	—	—	—	1,964
Cash collateral paid in support of energy risk management activities	321	2	—	—	323
Prepayments and other current assets	112	60	1,313	(1,189)	296
Total current assets	4,113	225	3,988	(1,189)	7,137
Net Property, Plant and Equipment	10,816	1,515	186	—	12,517
Other Assets					
Investment in subsidiaries	811	248	22,046	(23,105)	—
Equity investments in affiliates	47	489	—	—	536
Notes receivable – affiliate and capital leases, less current portion	6,507	380	2,130	(8,633)	384
Goodwill	1,868	—	—	—	1,868
Intangible assets, net	1,716	58	33	(31)	1,776
Nuclear decommissioning trust fund	412	—	—	—	412
Derivative instruments	758	—	—	—	758
Restricted cash supporting funded letter of credit facility	—	1,300	—	—	1,300
Other non-current assets	42	22	144	—	208
Total other assets	12,161	2,497	24,353	(31,769)	7,242
Total Assets	$ 27,090	$ 4,237	$ 28,527	$ (32,958)	$ 26,896
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 1,150	$ 223	$ 240	$ (1,150)	$ 463
Accounts payable	(2,665)	229	3,219	—	783
Derivative instruments	1,665	3	17	—	1,685
Deferred income taxes	515	(51)	(356)	—	108
Cash collateral received in support of energy risk management activities	408	—	—	—	408
Accrued expenses and other current liabilities	399	34	379	(39)	773
Total current liabilities	1,472	438	3,499	(1,189)	4,220
Other Liabilities					
Long-term debt and capital leases	1,857	991	14,533	(8,633)	8,748
Funded letter of credit	—	—	1,300	—	1,300
Nuclear decommissioning reserve	317	—	—	—	317

Nuclear decommissioning trust liability	272	—	—	—	272
Deferred income taxes	1,464	279	246	—	1,989
Derivative instruments	294	34	37	—	365
Out-of-market commodity contracts	248	6	—	(31)	223
Other non-current liabilities	504	29	609	—	1,142
Total non-current liabilities	4,956	1,339	16,725	(8,664)	14,356
Total liabilities	6,428	1,777	20,224	(9,853)	18,576
3.625% Preferred Stock	—	—	248	—	248
Stockholders' Equity	20,662	2,460	8,055	(23,105)	8,072
Total Liabilities and Stockholders' Equity	$ 27,090	$ 4,237	$ 28,527	$ (32,958)	$ 26,896

(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, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 873	$ 47	$ 492	$ (921)	$ 491
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	12	(17)	(854)	840	(19)
Depreciation and amortization	590	23	7	—	620
Provision for bad debts	46	—	—	—	46
Amortization of nuclear fuel	30	—	—	—	30
Amortization of financing costs and debt discount/premiums	—	5	18	—	23
Amortization of intangibles and out-of market commodity contracts	(17)	—	—	—	(17)
Changes in deferred income taxes and liability for uncertain tax benefits	480	3	(211)	—	272
Changes in nuclear decommissioning trust liability	26	—	—	—	26
Changes in derivative instruments	(48)	—	—	—	(48)
Changes in collateral deposits supporting energy risk management activities	(116)	—	—	—	(116)
Cash (used)/provided by changes in other working capital	(551)	(82)	466	—	(167)
Net Cash Provided/(Used) by Operating Activities	1,325	(21)	(82)	(81)	1,141
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(1,261)	—	(212)	1,473	—
Acquisition of Business	—	(142)	—	—	(142)
Investment in subsidiaries	—	1,724	(1,724)	—	—
Capital expenditures	(223)	(224)	(43)	—	(490)
Increase in restricted cash, net	1	(18)	—	—	(17)
Decrease in notes receivable	—	28	—	—	28
Purchases of emission allowances	(56)	—	—	—	(56)
Proceeds from sale of emission allowances	14	—	—	—	14
Investments in nuclear decommissioning trust fund securities	(245)	—	—	—	(245)
Proceeds from sales of nuclear decommissioning trust fund securities	219	—	—	—	219
Proceeds from renewable energy grants	84	18	—	—	102
Proceeds from sale of assets	1	—	29	—	30
Other	—	(16)	3	—	(13)

Net Cash (Used)/Provided by Investing Activities	(1,466)	1,370	(1,947)	1,473	(570)
Cash Flows from Financing Activities					
Proceeds from intercompany loans	126	86	1,261	(1,473)	—
Payment of intercompany dividends	(44)	(37)	—	81	—
Payment of dividends to preferred stockholders	—	—	(7)	—	(7)
Payments for treasury stock	—	—	(180)	—	(180)
Installment proceeds from sale of non-controlling interest in subsidiary	—	50	—	—	50
Net receipt from acquired derivatives that include financing elements	58	—	—	—	58
Proceeds from issuance of long-term debt	7	145	1,100	—	1,252
Proceeds from issuance of term loan for funded letter of credit facility	—	—	1,300	—	1,300
Increase of restricted cash supporting funded letter of credit	—	(1,301)	—	—	(1,301)
Proceeds from issuance of common stock	—	—	2	—	2
Payment of debt issuance costs	(1)	(8)	(61)	—	(70)
Payments for short and long-term debt	—	(282)	(247)	—	(529)
Net Cash Provided/(Used) by Financing Activities	146	(1,347)	3,168	(1,392)	575
Effect of exchange rate changes on cash and cash equivalents	—	(3)	—	—	(3)
Net Increase/(Decrease) in Cash and Cash Equivalents	5	(1)	1,139	—	1,143
Cash and Cash Equivalents at Beginning of Period	20	120	2,164	—	2,304
Cash and Cash Equivalents at End of Period	$ 25	$ 119	$ 3,303	$ —	$ 3,447

(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, 2011, and 2010. Also refer to NRG's Annual Report on Form 10-K for the year ended December 31, 2010, or 2010 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.

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 regulatory and environmental 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 with a significant presence in major competitive power markets in the United States. NRG is engaged in: the ownership, development, construction and operation of power generation facilities; the transacting in and trading of fuel and transportation services; the trading of energy, capacity and related products in the United States and select international markets; and the supply of electricity, energy services, and cleaner energy products to retail electricity customers in deregulated markets through its retail businesses, Reliant Energy, Green Mountain Energy, and Energy Plus.

The following table summarizes NRG's global generation portfolio by operating segment, which consists of 46 fossil fuel plants and 13 renewable facilities:

	Fossil Fuel, Nuclear, and Renewable (In MW)							
Generation Type	Texas	Northeast	South Central	West	Thermal	Total Domestic	Internat-ional	Total Global
Natural gas	4,930	1,300	2,630	2,130	100	11,090	—	11,090
Coal	4,190	1,600	1,495	—	15	7,300	1,005	8,305
Oil	—	4,015	—	—	—	4,015		4,015
Nuclear	1,175	—	—	—	—	1,175	—	1,175
Wind	450	—	—	—	—	450	—	450
Solar	—	—	—	70	—	70	—	70
Total generation capacity	10,745	6,915	4,125	2,200	115	24,100	1,005	25,105
Under Construction								
Natural gas	—	—	—	550	5	555	—	555
Solar [(a)]	—	—	—	935	—	935	—	935
Total under construction	—	—	—	1,485	5	1,490	—	1,490

(a) Includes partner interests of 196 MWs

In addition, the Company's thermal assets provide steam and chilled water capacity of approximately 1,140 megawatts thermal equivalent, or MWt, through its district energy business.

NRG's domestic generation facilities consist of intermittent, baseload, intermediate and peaking power generation facilities. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company's generation revenues. In addition, NRG's generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

NRG's retail businesses arrange for the transmission and delivery of electricity to customers, bill customers, collect payments for electricity sold and maintain call centers to provide customer service. Based on metered locations, as of September 30, 2011, NRG's retail businesses combined to serve approximately 2.1 million residential, small business, commercial and industrial customers.

Furthermore, NRG is focused on the development and investment in energy-related new businesses and new technologies where the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company. These investments include low or no GHG emitting energy generating sources, such as wind, solar thermal, solar photovoltaic, biomass, gasification, the retrofit of post-combustion carbon capture technologies, and fueling infrastructure for electric vehicle ecosystems.

NRG's Business Strategy

NRG's business strategy is intended to maximize shareholder 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 dual strategy is designed to perfect the Company's core business of competitive power generation and establish the Company as a leading provider of sustainable energy solutions that promote national energy security, while utilizing the Company's retail business to complement and advance both initiatives.

The Company's core business is focused on: (i) excellence in safety and operating performance of its existing operating assets, (ii) serving the energy needs of end-use residential, commercial and industrial customers in the Company's core markets, (iii) optimal hedging of baseload generation and retail load operations, while retaining optionality on the Company's gas fleet, (iv) repowering of power generation assets at existing sites and reducing environmental impacts, (v) pursuing selective acquisitions, joint ventures, divestitures and investments, and (vi) 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.

In addition, the Company believes that it is well-positioned to capture the opportunities arising out of a long-term societal trend towards sustainability as a result of technological developments and new product offerings in “green” energy. The Company's initiatives in this area of future growth are focused on: (i) renewables, with a concentration in solar and wind generation and development; (ii) fast start, high efficiency gas-fired capacity in the Company's core regions; (iii) electric vehicle ecosystems; and (iv) smart grid services. The Company's advances in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in the Company's 2010 Form 10-K and this Form 10-Q.

Environmental Matters

Environmental Regulatory Landscape

A number of regulations that could significantly impact the power generation industry are in development or under review by the U.S. EPA or state environmental agencies as of September 30, 2011, including MACT, NAAQS revisions, coal combustion byproducts, and once-through cooling. While most of these regulations have been under consideration for some time, they are expected to gain clarity in 2011 and 2012. The timing and stringency of these regulations will provide a framework for the retrofit of existing fossil plants and deployment of new, cleaner technologies in the next decade. The Company has included capital to meet anticipated Mercury and Air Toxics Standards, and the installation of BTA under the 316(b) Rule in the current estimated environmental capital expenditures. The Company cannot predict the impact of changes in these proposed rules nor future regulations and could face additional investments over time. However, NRG believes it is positioned to meet more stringent requirements through its planned capital expenditures, existing controls, and the use of Powder River Basin coal.

The U.S. EPA released CSAPR on July 7, 2011, with additional proposed updates on October 6, 2011. CSAPR will replace CAIR and is designed to bring 27 states into attainment with PM 2.5 and ozone NAAQS, reducing SO_2 and NO_x emissions from power plants. Proposed implementation will be through cap and trade programs starting in 2012 for Group 1 SO_2, Group 2 SO_2, Annual NO_x, and Ozone Season NO_x. In 2014, the SO_2 cap would be further reduced in Group 1 states. Under CSAPR, use of discounted Acid Rain SO_2 and CAIR NO_x allowances will be discontinued and replaced with completely distinct allowance programs. Acid Rain allowances will still be required on a 1:1 basis under the Acid Rain Program. NRG owns or has minority interests in plants in six states that are covered by the rule.

State	Group 1 SO_2	Group 2 SO_2	Annual NO_x	Ozone NO_x
IL	X		X	X

LA				X
MD	X		X	X
NY	X		X	X
PA	X		X	X
TX		X	X	X

The final rule differed from the proposed rule in that Texas was added into the Group 2 SO_2 and Annual NO_x programs, Delaware and Connecticut are no longer under the rule and Louisiana is limited to ozone season NO_x. In general, with the exception of Pennsylvania Annual and Ozone Season NO_x, these states saw tightening of the state budget between the proposed and final rules. On October 6, 2011, the U.S. EPA released an update which proposed additional increases to ten state budgets including Louisiana, New York, and Texas where NRG has operations and delayed implementation of the assurance provisions until 2014. These changes, when final, would result in additional allowances to NRG. NRG's integrated compliance strategy includes enhancing the performance of existing controls, fuel adjustments, and allowance trading. No material capital investment is expected. Several companies and states have filed legal challenges to the rule.
In the third quarter 2011, the Company recorded an impairment charge of $160 million 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.

On March 16, 2011, the U.S. EPA released the proposed Mercury and Air Toxics Standards to control emissions of hazardous air pollutants. NRG's existing and currently planned environmental capital expenditures are consistent with reductions required per the proposed rule.

In July 2004, the U.S. EPA published rules governing cooling water intake structures at existing power facilities commonly referred to as the 316(b) Rule. As a result of a decision by the U.S. Court of Appeals for the Second Circuit, the U.S. EPA suspended the rule in July 2007 while preparing a revised version. On March 28, 2011, the U.S. EPA released the proposed 316(b) Rule. States such as California and New York moved ahead with their own more stringent requirements for once-through cooled units, which are expected to satisfy the requirements of the proposed 316(b) Rule. On July 20, 2011, the New York State Department of Environmental Conservation, or NYDEC, announced the State's final policy on cooling water intake structures, confirming the Company's planned capital expenditure for cooling water intakes in that state. NRG expects to comply with these requirements with a mix of intake and operational modifications.

The California Air Resources Board adopted the state's GHG cap and trade program under AB 32 on October 20, 2011. The program starts in 2013.

Regulatory Matters

As operators of power plants and participants in wholesale energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include the U.S. Commodity Futures Trading Commission, or CFTC, FERC, NRC, and PUCT as well as other public utility commissions in certain states where NRG's generating or thermal assets are located. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO markets in which it participates. Certain of the retail entities are competitive Retail Electric Providers, or REPs, and as such are subject to the rules and regulations of the PUCT governing REPs, as well as other states where NRG is licensed to sell at retail. NRG must also comply with the mandatory reliability requirements imposed by the North American Electric Reliability Corporation, or NERC, and the regional reliability councils in the regions where the Company operates. The operations of, and wholesale electric sales from, NRG's Texas region 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.

California — On March 17, 2011, FERC issued an order on CAISO's proposal to replace its interim backstop Capacity Procurement Mechanism, or CPM, with a permanent version. The proposed CPM addresses capacity payments for generating units not contracted to fulfill California's Resource Adequacy requirements, but nevertheless needed for reliability. FERC accepted CAISO's proposal effective April 1, 2011, subject to refund and convened a technical conference to expeditiously explore issues related to the pricing of the CPM. Market participants are discussing resolution of these matters and have requested that FERC defer further action until the settlement agreement is finalized.

On September 8, 2011, the San Diego, CA area experienced a large blackout. All of the Company's generating units located within SDG&E's service territory were forced offline as a result of the blackout, but were able to resume operations as the transmission system was restored. Initial indications are that the Company's generating facilities in the area performed in compliance with all regulatory requirements both before and after the blackout during system restoration. The Company has received and is responding to several inquiries from regulators regarding the blackout.

New England — On April 13, 2011, FERC issued an order addressing proposed amendments submitted by ISO-NE to its Forward Capacity Market, or FCM, design, as well as two pending complaints. Among other market revisions, FERC's order extends the price floor for “at least” the fifth (2014/2015) and sixth (2015/2016) Forward Capacity Auctions in order to address the effect of historical out-of-market capacity. On August 22, 2011, ISO-NE made a compliance filing requesting permission to eliminate the price floor for the seventh (2016/2017) Forward Capacity Auction. Requests for rehearing have been submitted by numerous parties and compliance filings are pending and being contested.

New York — On November 30, 2010, the NYISO filed at FERC its proposed installed capacity demand curves for 2011/2012, 2012/2013, and 2013/2014. The demand curves are a critical determinant of capacity market prices. The Company and other market participants protested the NYISO's filing, and on January 28, 2011, FERC found in favor of generators on a number of issues principally related to determining the cost of new entry and the resulting adjustments to the demand curves should positively affect capacity clearing prices. On May 19, 2011, FERC granted rehearing to remove property taxes from the cost of new entry of new in-city generation, denied other requests for rehearing, and directed the NYISO to make a series of compliance filings to implement the new rate. A coalition of New York in-city generators, including the Company, is seeking rehearing of the May 19, 2011, order. On September 15, 2011, FERC issued an order accepting the NYISO's compliance filing, and directing the NYISO to implement the new rate.

In addition, on June 3, 2011, as amended on June 15, 2011, the same coalition of New York in-city generators filed a complaint with FERC seeking additional transparency into: whether (i) the NYISO was correctly evaluating if new entrants into the capacity markets should be subject to mitigation and, if so, (ii) the NYISO was appropriately setting the level of any mitigation. On June 29, 2011, the NYISO released its July spot capacity auction clearing prices for New York City, which significantly decreased over June clearing prices. Clearing prices for the third quarter 2011 were comparable to the July clearing prices. The apparent cause of this decrease was a decision by the NYISO to allow a new entrant to bid into the July spot capacity auction, either without mitigation or without proper mitigation. Additionally, another new entrant has since indicated that it also received a mitigation exemption from NYISO and that it intends to begin participating in the NYISO capacity market starting with the May 2012 capability period. The addition of this second new entrant may further affect capacity clearing prices in New York. On July 10, 2011, in response to the July spot auction capacity clearing prices, two generators filed a second complaint alleging that the NYISO had improperly exempted both new entrants from mitigation, and requested that FERC immediately direct the NYISO to apply its offer-floor market mitigation rules to both new entrants, to resettle the July capacity spot auction, and other relief. Certain of NRG's subsidiaries filed a motion to intervene at FERC in support of applying offer-floor mitigation to the new entrants. On August 31, 2011, FERC issued an order on the second complaint directing the NYISO to provide additional information, on a confidential basis, regarding its mitigation decisions, and requiring additional comments, which were filed on September 23, 2011. Both complaints are pending before FERC.

PJM — On April 12, 2011, FERC issued an order addressing a complaint filed by PJM Power Providers Group seeking to require PJM to address the potential adverse impacts of out-of-market generation on the PJM capacity market, as well as PJM's subsequent submission seeking revisions to the capacity market design, in particular the Minimum Offer Price Rule, or MOPR. In its order, FERC generally strengthened the MOPR and the protections against market price distortion from out-of-market generation. Requests for rehearing have been submitted by numerous parties and compliance filings are pending and being contested. FERC convened a technical conference on July 28, 2011, to further explore issues associated with self-supply and out-of-market generation. The outcome of this proceeding could affect the Company's ability to meet its obligations under New Jersey's Long-Term Capacity Agreement Pilot Program.

South Central — On April 25, 2011, Entergy Corporation, or Entergy, announced that it will pursue joining the Midwest Independent System Operator regional transmission organization, or MISO, with a current target date for joining of

December 2013. Entergy's proposal is subject to approval from the regulatory commissions of the states of Arkansas, Louisiana, Mississippi, and Texas, as well as the City of New Orleans. The Company's South Central region is dependent upon Entergy's transmission system to conduct its business, and thus would necessarily move with Entergy into MISO. This development is not expected to materially impact the Company's ability to serve its customers in the region, and we are continuing to analyze the impact of the possible changes in transmission access and market design.

Texas — On February 2, 2011, ERCOT experienced unusually cold temperatures that resulted in a power emergency, rotating blackouts, and a new all-time winter peak of 56,334 MW (on February 10, 2011, ERCOT again set a new winter peak of 57,315 MW). Several regulators are reviewing the circumstances surrounding the cold snap, and have issued requests for information to market participants, including NRG. During the load shed event, the Company satisfied its load responsibilities and wholesale obligations, and complied with ERCOT's instructions. On September 15, 2011, FERC and NERC issued the results of its joint investigation into the events of February, making operational recommendations, but finding no wrong-doing. The ERCOT IMM also issued a report that determined that there was no market manipulation.

Nuclear Regulatory Commission, or NRC, Task Force Report — On July 12, 2011, the NRC Near-Term Task Force, or the Task Force, issued its report, which reviewed nuclear processes and regulations in light of the accident at the Fukushima Daiichi Nuclear Power Station in Japan. The Task Force concluded that U.S. nuclear plants are operating safely and did not identify changes to the existing nuclear licensing process nor recommend fundamental changes to spent nuclear fuel storage. The Task Force report made recommendations in three key areas: the NRC's regulatory framework, specific plant design requirements, and emergency preparedness and actions. STPNOC expects the report to be the first step in a longer-term review that the NRC will conduct, along with seeking broad stakeholder input. STPNOC continues to apply lessons learned and work with regulators and industry organizations on appropriate assessments and actions. Until further actions are taken by the NRC, the Company cannot predict the impact of the recommendations in the NRC Task Force report, and could face additional investments at STP Units 1 & 2.

Changes in Accounting Standards

None.

Consolidated Results of Operations

The following table provides selected financial information for the Company:

	Three months ended September 30,			Nine months ended September 30,		
(In millions except otherwise noted)	2011	2010	Change %	2011	2010	Change %
Operating Revenues						
Energy revenue [(a)]	$465	$812	(43)%	$1,592	$2,191	(27)%
Capacity revenue [(a)]	196	215	(9)	564	628	(10)
Retail revenue	1,882	1,593	18	4,526	4,179	8
Mark-to-market for economic hedging activities	81	(2)	N/A	149	(65)	329
Contract amortization	(18)	(23)	22	(109)	(137)	20
Thermal revenue	36	39	(8)	109	105	4
Other revenues [(b)]	32	51	(37)	116	132	(12)
Total operating revenues	2,674	2,685	—	6,947	7,033	(1)
Operating Costs and Expenses						
Generation cost of sales [(a)]	836	711	18	1,968	1,649	19
Retail cost of sales [(a)]	871	772	13	2,163	2,204	(2)
Mark-to-market for economic hedging activities	40	62	(35)	(68)	23	(396)
Contract and emissions credit amortization [(c)]	16	3	433	37	8	363
Thermal cost of sales	17	18	(6)	49	48	2
Other cost of operations	273	269	1	836	871	(4)
Total cost of operations	2,053	1,835	12	4,985	4,803	4
Depreciation and amortization	238	210	13	665	620	7
Impairment charge on emission allowances	160	—	N/A	160	—	N/A
Selling, general and administrative	169	172	(2)	479	441	9
Development costs	11	14	(21)	32	36	(11)
Total operating costs and expenses	2,631	2,231	18	6,321	5,900	7
Gain on sale of assets	—	—	N/A	—	23	(100)
Operating Income	43	454	(91)	626	1,156	(46)
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	16	16	—	26	41	(37)
Impairment charge on investment	(3)	—	N/A	(495)	—	N/A
Other income, net	5	11	(55)	13	34	(62)
Loss on debt extinguishment	(32)	(1)	N/A	(175)	(2)	N/A
Interest expense	(164)	(168)	(2)	(504)	(467)	8
Total other expense	(178)	(142)	25	(1,135)	(394)	188
(Loss)/Income before income tax expense	(135)	312	(143)	(509)	762	(167)
Income tax (benefit)/expense	(80)	89	(190)	(815)	271	(401)
Net (Loss)/Income	(55)	223	(125)	306	491	(38)
Less: Net loss attributable to noncontrolling interest	—	—	—	—	(1)	(100)
Net (Loss)/Income Attributable to NRG Energy, Inc.	$(55)	$223	(125)	$306	$492	(38)
Business Metrics						
Average natural gas price — Henry Hub ($/MMBtu)	4.20	4.38	(4)%	4.21	4.59	(8)%

(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

Management’s discussion of the results of operations for the three months ended September 30, 2011, and 2010

(Loss)/Income before income tax expense — The pre-tax loss of $135 million for the three months ended September 30, 2011, compared to pre-tax income of $312 million for the three months ended September 30, 2010, primarily reflects:

- a $322 million decrease in gross margin, which includes $146 million primarily resulting from the unprecedented August 2011 heat wave in Texas
- a $160 million impairment charge on emissions allowances, and
- a $32 million loss on the extinguishment of the Senior Credit Facility.

Net income — The decrease in net income of $278 million primarily reflects the drivers discussed above offset by the tax benefit for the three months ended September 30, 2011, of $80 million, compared with income tax expense of $89 million in the comparable period.

Wholesale Power Generation gross margin

The following is a discussion of gross margin for NRG's wholesale power generation regions, adjusted to eliminate intersegment activity, primarily with Reliant Energy and Green Mountain Energy.

	Three months ended September 30, 2011							
(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Total Wholesale Power Generation	Eliminations	Consolidated Total
Energy revenue	$ 725	$ 207	$ 205	$ 23	$ 13	$ 1,173	$ (708)	$ 465
Capacity revenue	9	79	61	33	18	200	(4)	196
Thermal revenue					36	36		36
Other revenue	24	1	6	(2)	9	38	(6)	32
Generation revenue	758	287	272	54	76	1,447	$ (718)	$ 729
Generation cost of sales	(428)	(176)	(197)	(9)	(26)	(836)	—	
Thermal cost of sales	—	—	—	—	(17)	(17)	—	
Generation cost of sales	(428)	(176)	(197)	(9)	(43)	(853)		
Generation gross margin	$ 330	$ 111	$ 75	$ 45	$ 33	$ 594		
Business Metrics								
MWh sold (in thousands)	14,656	3,191	5,749	158				
MWh generated (in thousands)	14,217	2,611	4,488	158				
Average on-peak market power prices ($/MWh)	$ 108.89	$ 59.05	$ 40.07	$ 40.95				

Three months ended September 30, 2010

(In millions except otherwise noted)	Texas	Northeast	South Central	West	Other	Total Wholesale Power Generation	Eliminations	Consolidated Total
Energy revenue	$855	$267	$115	$15	$11	$ 1,263	$ (451)	$ 812
Capacity revenue	7	107	61	28	17	220	(5)	215
Thermal revenue	—	—	—	—	39	39	—	39
Other revenue	37	21	3	—	1	62	(11)	51
Generation revenue	899	395	179	43	68	1,584	$ (467)	$ 1,117
Generation cost of sales	(364)	(204)	(114)	(5)	(24)	(711)		
Thermal cost of sales	—	—	—	—	(18)	(18)		
Generation cost of sales	(364)	(204)	(114)	(5)	(42)	(729)		
Generation gross margin	$535	$191	$65	$38	$26	$ 855		

Business Metrics						
MWh sold (in thousands)	13,646	3,776	3,221	3,458	1,980	100
MWh generated (in thousands)	12,995	3,443	2,366	3,048	1,688	100
Average on-peak market power prices ($/MWh)	$48.15	$68.32		$45.58		$39.54

Three months ended September 30,

Weather Metrics	Texas	Northeast	South Central	West
2011				
CDDs [(a)]	1,877	585	1,134	606
HDDs [(a)]	—	86	44	52
2010				
CDDs	1,620	632	1,280	548
HDDs	3	98	19	77
30 year average				
CDDs	1,485	430	997	506
HDDs	—	159	33	108

(a) 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.

Generation gross margin — decreased by $261 million, including intercompany sales, during the three months ended September 30, 2011, compared to the same period in 2010, due to:

Decrease in Texas region	$ (205)
Decrease in Northeast region	(80)
Increase in South Central region	10
Increase in West region	7
Other	7

	$(261)

The decrease in gross margin in the Texas region was driven by:	
Lower energy revenue due to a 27% decrease in realized prices, which reflects lower hedged prices in 2011	$(150)
Losses incurred due to hedging and trading optimization activities, and the impact of unplanned outages at gas plants as ERCOT power prices spiked in August 2011	(90)
Favorable gross margin impact from a 5% increase in coal generation driven by higher economic dispatch and fewer unplanned outages	17
Lower purchased energy costs due to fewer unplanned outages at baseload plants	15
Favorable gross margin impact from a 37% increase in natural gas generation driven by warmer weather compared to 2010	10
Other	(7)
	$(205)

The decrease in gross margin in the Northeast region was driven by:	
Lower gross margin from coal plants due to a 20% decrease in realized energy prices	$(20)
Lower gross margin from coal plants due to a 29% decrease in generation as units were less economic as compared to the prior year	(18)
Lower gross margin from oil and gas plants due to an 11% decrease in realized energy prices and a 71% decrease in generation offset by related fuel costs	(5)
Lower capacity revenue due to 30% lower prices and 5% lower volumes partially offset by favorable hedges for New York	(20)
Lower capacity revenue due to significantly lower LFRM prices and volumes in New England	(8)
Other	(9)
	$(80)

The increase in gross margin in the South Central region was driven by:	
Impact of a decrease in average realized merchant prices	$(123)
Higher gross margin from merchant energy due to an increase in MWh sold, offset in part by higher costs of sales, primarily related to the addition of the Cottonwood facility and capacity from summer tolling agreements	126
Higher contract revenue from new contracts with two regional municipalities	11
Coal and other costs of energy increased due to a 1% increase in generation and an increase in prices driven by higher transportation costs	(4)
	$10

The increase in gross margin in the West region was driven by:	
Higher merchant revenue due to a 58% increase in generation related to the addition of a new solar facility as well as warmer weather as compared to the prior year quarter	$8
Higher capacity revenue due to additional sales at El Segundo and a price increase on the Cabrillo I tolling agreement	5
Higher natural gas costs related to the increase in merchant revenue due to warmer weather than in the prior year quarter	(4)
Other	(2)
	$7

Retail gross margin

The Company's retail gross margin, which reflects retail operating revenues less retail cost of sales, include the results of NRG's Reliant Energy business segment, as well as the results of Green Mountain Energy which is included in NRG's Corporate business segment.

	Three months ended September 30, 2011			
(In millions)	Reliant Energy	Green Mountain [a]	Eliminations	Consolidated Total
Retail operating revenues	$1,654	$230	$(2)	$1,882
Retail cost of sales	1,401	186	(716)	871

(a) Green Mountain Energy was acquired in November 2010.

	Three months ended September 30, 2010		
(In millions)	Reliant Energy	Eliminations	Consolidated Total
Retail operating revenues	$1,593	$—	$1,593
Retail cost of sales	1,239	(467)	772

Reliant Energy

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

Selected Income Statement Data

	Three months ended September 30,	
(In millions except otherwise noted)	2011	2010
Operating Revenues		
Mass revenues	$1,035	$997
Commercial and Industrial revenues	541	546
Supply management revenues	78	50
Retail operating revenues [a]	1,654	1,593
Retail cost of sales [b]	1,401	1,239
Retail gross margin	$253	$354
Business Metrics		
Electricity sales volume — GWh		
Mass	8,389	7,547
Commercial and Industrial [a]	7,231	7,179
Average retail customers count (in thousands, metered locations)		
Mass	1,482	1,473
Commercial and Industrial [a]	63	63
Retail customers count (in thousands, metered locations)		
Mass	1,493	1,468
Commercial and Industrial [a]	63	62

Weather Metrics		
CDDs [(c)]	2,050	1,820
HDDs [(c)]	—	—

(a) Includes customers of the Texas General Land Office for which the Company provides services.
(b) Includes intercompany purchases from the Texas region of $627 million and $467 million, respectively.
(c) The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Reliant Energy serves its customer base.

- Retail gross margin — Reliant Energy's gross margin decreased $101 million for the three months ended September 30, 2011, compared to the same period in 2010, driven by:

Unfavorable gross margin impact of an unprecedented heat wave in Texas. Higher supply costs for incremental weather volume resulted in negative margins	$(56)
Favorable volume impact on gross margin due to a 1% increase in customer counts and higher average usage driven by a change in customer mix	25
Decrease in retail margins of 17% due to lower pricing on acquisitions and renewals consistent with competitive offers	(55)
Estimated favorable impact in 2010 as compared to 2011 from the termination of out-of-market supply contracts in conjunction with 2009 CSRA unwind	(15)
	$(101)

- Trends — Competition and lower unit margins on acquisitions and renewals could drive lower revenues and gross margin in the future. Mass customer counts increased by 16,000 since June 30, 2011, continuing the trend in 2011 of a net customer count increase each quarter. Warmer than normal weather in both periods resulted in higher customer usage of 15% in 2011 and 4% in 2010 when compared to ten-year normal weather.

Green Mountain Energy

The following is a discussion of retail gross margin for Green Mountain Energy for the three months ended September 30, 2011:

Retail operating revenues	$230
Retail cost of sales [(a)]	186
Retail gross margin	$44

(a) Includes intercompany purchases of $89 million

- Retail gross margin — Green Mountain Energy's gross margin of $44 million for the three months ended September 30, 2011, reflects increased customer usage due to warmer than normal weather, as compared to the ten-year average. During certain periods within the quarter, the unprecedented heat wave in Texas led to abnormally high power prices in ERCOT, which resulted in increased supply costs for the incremental customer usage. Revenues were generated 64% and 36% from residential and commercial customers, respectively. Total metered customer counts were approximately 400,000 and increased approximately 4% or 14,000 from June 30, 2011.

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that did not qualify for cash flow hedge accounting and ineffectiveness on cash flow hedges. Total net mark-to-market results increased by $105 million during the three months ended September 30, 2011, compared to the same period in 2010.

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

	Three months ended September 30, 2011								
	Reliant Energy	Texas	Northeast	South Central	West	Thermal	Corporate [a]	Elimination [b]	Total
	(In millions)								
Mark-to-market results in operating revenues									
Reversal of previously recognized unrealized losses/(gains) 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									