UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended: September 30, 2006

Commission File Number: 001-15891

NRG Energy, Inc.

(Exact name of Registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer (as defined in Rule 12 b-2 of the Exchange Act).

Large accelerated filer ☑ **Accelerated filer** ☐ **Non-accelerated filer** ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ **No** ☑

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15 (d) of the Securities and Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.

Yes ☑ **No** ☐

As of November 2, 2006, there were 126,442,942 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 includes forward-looking statements within the meaning of Section 27A of the 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 which 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 Risks Related to NRG Energy, Inc. in Item 1A of NRG Energy, Inc.’s 2005 Annual Report on Form 10-K and the following:

- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- 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 Energy, Inc. may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of NRG Energy, Inc.’s risk management policies and procedures, and the ability of NRG Energy, Inc.’s counterparties to satisfy their financial commitments;
- Counterparties’ collateral demands and other factors affecting NRG Energy, Inc.’s liquidity position and financial condition;
- NRG Energy, Inc.’s ability to operate its businesses efficiently, manage capital expenditures and costs tightly (including general and administrative expenses), and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;
- NRG Energy, Inc.’s potential inability 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;
- Price mitigation strategies and other market structures employed by independent system operators, or ISO, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate NRG Energy, Inc’s generation units for all of its costs;
- NRG Energy, Inc.’s ability to borrow additional funds and access capital markets, as well as NRG Energy, Inc’s substantial indebtedness and the possibility that NRG Energy, Inc. may incur additional indebtedness going forward;
- Operating and financial restrictions placed on NRG Energy, Inc. contained in the indentures governing NRG Energy, Inc.’s 7.25% and 7.375% unsecured senior notes due 2014 and 2016, respectively, in NRG Energy, Inc.’s senior secured credit facility and in debt and other agreements of certain of NRG Energy, Inc. subsidiaries and project affiliates generally;
- Significant operating and financial restrictions which may be placed on NRG Energy, Inc. as a result of the new financing transaction described in this Form 10-Q and instruments governing its existing indebtedness; and
- NRG Energy, Inc’s ability to implement its recently-announced strategy of developing and building new power generation facilities, including new nuclear units and integrated gasification combined cycle, or IGCC, units.

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 Energy, Inc.’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:

Acquisition	February 2, 2006 acquisition of Texas Genco LLC
Acquisition Agreement	Acquisition Agreement dated September 30, 2005 underlying the February 2, 2006 acquisition of Texas Genco LLC, now referred to as NRG Texas
APB 18	Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*
BTA	Best Technology Available
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
Capital Allocation Program	Share repurchase program as described in Note 8 to the Condensed Consolidated Financial Statements
CDWR	California Department of Water Resources
CL&P	Connecticut Light & Power
DNREC	Delaware Department of Natural Resources and Environmental Control
EFOR	Equivalent Forced Outage Rates — considers the equivalent impact that forced de-ratings have in addition to full forced outages
EITF 02-3	Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
FASB	Financial Accountings Standards Board
FERC	Federal Energy Regulatory Commission
Fresh Start	Reporting requirements as defined by SOP 90-7
Hedge Reset	Net settlement of existing hedges and reestablishment of new hedge positions
IGCC	Integrated Gasification Combined Cycle
ISO	Independent System Operator, also referred to as regional transmission organizations, or RTO
ISO-NE	ISO New England, Inc.
LIBOR	London Inter-Bank Offered Rate
MDE	Maryland Department of the Environment
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NiMo	Niagara Mohawk Power Corporation
NOx	Nitrogen oxides
NOL	Net operating loss
NOV	Notice of Violation
NQSO	Non-qualified stock option
NYISO	New York Independent System Operator
NYSDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
Phase II 316(b) Rule	A section of the Clean Water Act regulating cooling water intake structures
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
PMI	Power Marketing Inc.
PPA	Power Purchase Agreement
PRB Coal	Coal produced in the northeastern Wyoming and southeastern Montana, which has low sulfur content
PUCT	Public Utility Commission of Texas
RMR	Reliability must-run
SEC	Securities and Exchange Commission
Sellers	Former holders of Texas Genco LLC shares
SERC	South East Electric Reliability Commission
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS 71	SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*
SFAS 109	SFAS No. 109, *Accounting for Income Taxes*
SFAS 123 (R)	SFAS No. 123 (revised 2004), *Share-Based Payment*
SFAS 133	SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*
SFAS 141	SFAS No. 141, *Business Combinations*
SFAS 142	SFAS No. 142, *Goodwill and Other Intangible Assets*
SFAS 143	SFAS No. 143, *Accounting for Asset Retirement Obligations*

GLOSSARY OF TERMS CONTINUED

SFAS 143	SFAS No. 143, *Accounting for Asset Retirement Obligations*
SFAS 144	SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*
SFAS 150	SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*
SO_2	Sulfur dioxide
SOP 90-7	Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*
STP	South Texas Project — A nuclear generating facility located in Bay City, Texas in which NRG has a 44% ownership interest
NRG Texas	Formerly Texas Genco LLC, now a subsidiary of NRG Energy, Inc. following the Acquisition
US	United States of America
USEPA	United States Environmental Protection Agency
US GAAP	Generally Accepted Accounting Principles in the U.S.
WCP	West Coast Power (Generation) Holdings, Inc.

PART I — FINANCIAL INFORMATION

Item 1 — Condensed Consolidated Financial Statements and Notes

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

(In millions, except for per share amounts)	Three months ended September 30 2006	Three months ended September 30 2005	Nine months ended September 30 2006	Nine months ended September 30 2005
Operating Revenues				
Revenues from majority-owned operations	$ 2,000	$ 687	$ 4,479	$ 1,723
Operating Costs and Expenses				
Cost of majority-owned operations	1,055	604	2,478	1,378
Depreciation and amortization	148	41	443	121
General, administrative and development	79	42	220	136
Impairment charges	—	6	—	6
Corporate relocation charges	—	2	—	6
Total operating costs and expenses	1,282	695	3,141	1,647
Operating Income/(Loss)	718	(8)	1,338	76
Other Income (Expense)				
Equity in earnings of unconsolidated affiliates	17	29	46	82
Write downs and gains/(losses) on sales of equity method investments	(3)	4	8	16
Other income, net	30	10	118	41
Refinancing expense	—	(19)	(178)	(54)
Interest expense	(154)	(43)	(420)	(141)
Total other expense	(110)	(19)	(426)	(56)
Income/(Loss) From Continuing Operations Before Income Taxes	608	(27)	912	20
Income tax expense	235	10	324	24
Income/(Loss) From Continuing Operations	373	(37)	588	(4)
Income from discontinued operations, net of income tax expense	49	10	63	24
Net Income/(Loss)	422	(27)	651	20
Dividends for Preferred Shares	14	4	37	12
Income/(Loss) Available for Common Stockholders	$ 408	$ (31)	$ 614	$ 8
Weighted Average Number of Common Shares Outstanding — Basic	136	84	130	86
Income/(Loss) From Continuing Operations per Weighted Average Common Share — Basic	$ 2.64	$ (0.51)	$ 4.22	$ (0.21)
Income From Discontinued Operations per Weighted Average Common Share — Basic	0.36	0.12	0.48	0.28
Net Income/(Loss) per Weighted Average Common Share — Basic	$ 3.00	$ (0.39)	$ 4.70	$ 0.07
Weighted Average Number of Common Shares Outstanding — Diluted	159	84	151	86
Income/(Loss) From Continuing Operations per Weighted Average Common Share — Diluted	$ 2.34	$ (0.51)	$ 3.85	$ (0.21)
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.31	0.12	0.41	0.28
Net Income/(Loss) per Weighted Average Common Share — Diluted	$ 2.65	$ (0.39)	$ 4.26	$ 0.07

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except shares and par value)	September 30, 2006 (unaudited)	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,388	$ 493
Restricted cash	74	49
Accounts receivable, less allowance for doubtful accounts of $3 and $2	433	249
Inventory	397	240
Deferred income taxes	59	—
Derivative instruments valuation	961	387
Collateral on deposits in support of energy risk management activities	132	438
Prepayments and other current assets	214	187
Current assets – held-for-sale	—	43
Current assets — discontinued operations	13	110
Total current assets	3,671	2,196
Property, plant and equipment, net of accumulated depreciation of $814 and $332	11,686	2,609
Other Assets		
Equity investments in affiliates	319	602
Notes receivable, less current portion	468	457
Goodwill	1,547	—
Intangible assets, net of accumulated amortization of $213 and $79	1,001	257
Intangible assets held-for-sale	53	—
Nuclear decommissioning trust fund	331	—
Derivative instruments valuation	360	18
Funded letter of credit	—	350
Deferred income taxes	27	26
Other non-current assets	244	124
Non-current assets – discontinued operations	14	827
Total other assets	4,364	2,661
Total Assets	$ 19,721	$ 7,466
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 123	$ 95
Accounts payable	278	241
Derivative instruments valuation	901	679
Accrued expenses and other current liabilities	485	172
Current liabilities — discontinued operations	8	170
Total current liabilities	1,795	1,357
Other Liabilities		
Long-term debt and capital leases	7,826	2,410
Nuclear decommissioning reserve	278	—
Nuclear decommissioning trust liability	319	—
Deferred income taxes	362	128
Derivative instruments valuation	369	56
Out-of-market contracts	2,128	298
Other non-current liabilities	386	170
Non-current liabilities — discontinued operations	5	569
Total non-current liabilities	11,673	3,631
Total Liabilities	13,468	4,988
Minority Interest	1	1
3.625% Convertible perpetual preferred stock (at liquidation value, net of issuance costs)	247	246
Commitments and Contingencies		
Stockholders' Equity		
Preferred stock (at liquidation value, net of issuance costs)	892	406
Common Stock; $.01 par value; 500,000,000 shares authorized; 137,030,642 and 80,701,888 outstanding	1	1
Additional paid-in capital	4,458	2,431
Retained earnings	782	261
Less treasury stock, at cost — 6,113,000 and 19,346,788 shares	(297)	(663)
Accumulated other comprehensive income/(loss)	169	(205)
Total stockholders' equity	6,005	2,231
Total Liabilities and Stockholders' Equity	$ 19,721	$ 7,466

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 2006	2005
Cash Flows from Operating Activities		
Net income	$ 651	$ 20
Adjustments to reconcile net income to net cash provided/(used) by operating activities		
Distributions in excess/(less than) equity in earnings of unconsolidated affiliates	(27)	1
Depreciation and amortization of nuclear fuel	490	145
Amortization of financing costs and debt discount	24	8
Amortization of intangibles and out-of-market contracts	(393)	16
Amortization of unearned equity compensation	13	8
Write-off of deferred financing costs and debt premium	47	(7)
Write down and (gains) on sale of equity method investments	(8)	(16)
Asset impairment	—	6
Changes in deferred income taxes	309	(54)
Nuclear decommissioning trust liability	9	—
Minority interest	—	1
Loss on sale of equipment	3	—
Changes in derivatives	(301)	252
Gain on legal settlement	(67)	(14)
Gain on sale of discontinued operations	(71)	(11)
Gain on sale of emission allowances	(68)	—
Changes in collateral deposits supporting energy risk management activities	349	(598)
Cash provided by changes in other working capital, net of acquisition and disposition affects	88	129
Net Cash Provided/(Used) by Operating Activities	1,048	(114)
Cash Flows from Investing Activities		
Acquisition of Texas Genco LLC, net of cash acquired	(4,304)	—
Acquisition of WCP and Padoma, net of cash acquired	(32)	—
Capital expenditures	(159)	(46)
Decrease/(Increase) in restricted cash , net	(24)	18
Decrease in notes receivable	22	100
Purchases of emission allowances	(76)	—
Proceeds from sale of emission allowances	97	—
Investments in nuclear decommissioning trust fund securities	(158)	—
Proceeds from sales of nuclear decommissioning trust fund securities	149	—
Proceeds from sale of equipment	1	—
Proceeds from sale of investments	86	70
Proceeds from sale of discontinued operations	239	36
Return of capital from equity method investments and projects	—	1
Net Cash Provided/(Used) by Investing Activities	(4,159)	179
Cash Flows from Financing Activities		
Payment of dividends to preferred stockholders	(37)	(12)
Payment for treasury stock	(297)	(251)
Payment of minority interest obligations	—	(4)
Borrowing under revolving credit facility, net	—	80
Funded letter of credit	350	—
Proceeds from issuance of common stock, net of issuance costs	986	—
Proceeds from issuance of preferred shares, net of issuance costs	486	246
Proceeds from issuance of long-term debt, net	7,373	249
Payment of deferred debt issuance costs	(174)	(2)
Payments for short and long-term debt	(4,697)	(979)
Net Cash Provided/(Used) by Financing Activities	3,990	(673)
Change in Cash from Discontinued Operations	14	17
Effect of Exchange Rate Changes on Cash and Cash Equivalents	2	(1)
Net Increase in Cash and Cash Equivalents	895	592
Cash and Cash Equivalents at Beginning of Period	493	1,069
Cash and Cash Equivalents at End of Period	$ 1,388	$ 477

See notes to condensed consolidated financial statements.

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

Note 1 — Basis of Presentation

NRG Energy, Inc., "NRG", or the "Company", is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the marketing and trading of energy, capacity and related products in the United States.

The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission'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 accounting policies NRG follows are set forth in Note 2, *Summary of Significant Accounting Policies,* to the Company's financial statements in its Annual Report on Form 10-K for the fiscal year ended December 31, 2005. The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K for the fiscal year ended December 31, 2005. Interim results are not necessarily indicative of results for a full fiscal year.

In the opinion of management, the accompanying unaudited interim condensed consolidated financial statements contain all material adjustments (consisting of normal, recurring accruals) necessary to fairly present NRG's consolidated financial position as of September 30, 2006, the results of NRG's operations for the three months and nine months ended September 30, 2006 and 2005, and NRG's cash flows for the nine months ended September 30, 2006 and 2005. Certain prior-year amounts have been reclassified for comparative purposes.

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.

Emission Allowances

NRG actively manages its SO_2 and NO_X emission allowances, as well as fuels, and accounts for this asset optimization activity related to emission allowances and other fuel commodities under EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. As such, revenues and costs for these activities are reflected on a net basis in the consolidated statement of operations. Emission allowances allocated for trading are considered to be intangible assets held-for-sale and are valued at the lower of their weighted average cost or fair value. In accordance with their classification as intangible assets, purchases and sales of emissions allowances are classified as an investing activity with the corresponding gains and/or losses on the sales recorded as an adjustment to operating activity in the consolidated statement of cash flows.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. NRG accounts for goodwill and other intangibles under the provisions of SFAS 142, *Goodwill and Other Intangible Assets,* and consequently NRG does not amortize goodwill. SFAS 142 requires us to evaluate goodwill and other intangibles not subject to amortization for impairment at least annually or more often if events and circumstances such as adverse changes in the business climate, indicate there may be impairment. Goodwill is impaired if the carrying value of the business exceeds its fair value. Annually, NRG estimates the fair value of the businesses the Company has acquired using estimated future cash flows or other methods to assess fair value. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. SFAS 142 also requires the amortization of intangible assets with finite lives.

New Accounting Pronouncements

NRG adopted SFAS 123(R) and Staff Accounting Bulletin 107, or SAB 107, on January 1, 2006 under a modified version of prospective application, or the modified prospective method. Under the modified prospective method, NRG applied the provisions of SFAS 123(R) to new awards of stock-based compensation and to awards modified, repurchased, or cancelled after the required effective date. SFAS 123(R) requires that NRG apply a forfeiture rate to existing awards and to calculate the retroactive impact of such application. If material, NRG must recognize in income the cumulative effect of this as a change in accounting principle as of the required effective date. Upon adoption of SFAS 123(R) on January 1, 2006, NRG applied a forfeiture rate to the Company's existing awards and recognized in income approximately $1.1 million, or $0.8 million, net of tax, as a reduction to compensation expense for the nine months ended September 30, 2006. This amount did not materially affect the Company's consolidated financial position, results of operations or statement of cash flows for the nine months ended September 30, 2006.

On January 1, 2006, NRG adopted EITF Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*, or EITF 04-6. EITF 04-6 provides that costs incurred to remove overburden and waste material to access coal seams, or stripping costs , during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005. MIBRA GmbH, or MIBRAG, in which NRG holds a 50% equity investment, has mining operations which were negatively affected by this pronouncement. MIBRAG had capitalized costs totaling approximately $185 million (€157 million), representing the stripping costs incurred during production as of December 31, 2005. As a result of the Adoption of EITF 04-6, such costs are no longer allowed to be capitalized and in accordance with the new pronouncement, were written off to retained earnings. The adoption of EITF 04-6 did not have a material impact on NRG's consolidated results of operations, but did have a material impact on NRG's consolidated financial position. Upon adoption of EITF 04-6 on January 1, 2006, NRG's investment in MIBRAG was reduced by 50% of the above mentioned asset, approximately $93 million after-tax, with an offsetting charge to retained earnings.

On January 1, 2006, NRG adopted EITF Issue No. 05-5, *Accounting for Early Retirement or Post-employment Programs with Specific Features (such as terms specified in Altersteilzeit Early Retirement Arrangements)*, or EITF 05-5. EITF 05-5 provides guidance on the accounting for early retirement or post-employment programs with specific features, and specifically the terms of Altersteilzeit early retirement arrangements. The Altersteilzeit, or ATZ, arrangement is a voluntary early retirement program in Germany designed to create an incentive for employees, within a certain age group, to transition from employment into retirement before their legal retirement age. If certain criteria are met by the employer, the German government provides to the employer a subsidy for bonuses paid to the employee and the additional contributions paid by the employer into the German government pension scheme under an ATZ arrangement for a maximum of six years. The Task Force reached a consensus that the employer should recognize the government subsidy when it meets the necessary criteria and is entitled to the subsidy. The Task Force also reached a consensus that payments made by the employer relative to the bonus feature and the additional contributions into the German government pension scheme, or the additional compensation, should be accounted for as a post-employment benefit under SFAS No. 112, *Employers' Accounting for Post-employment Benefits*, which prescribes that an entity should recognize the additional compensation over the period from the point at which the employee signs the ATZ contract until the end of the active service period. Upon adoption of EITF 05-5 on January 1, 2006, NRG recognized additional equity in earnings of unconsolidated affiliates of approximately $2.1 million, after-tax, from the Company's MIBRAG interest. This amount reflects the cumulative effect of the adoption of EITF 05-5, and did not materially affect NRG's consolidated financial position, results of operations or statement of cash flows for the period ending September 30, 2006.

During the first quarter 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments — an amendment of FASB Statements Nos. 133 and 140*, or SFAS 155. This statement allows for fair value measurement of certain financial instruments, and eliminates certain exemptions from fair value measurement found within SFAS 133. The fair value election would not be available for hybrid instruments with embedded derivative features that are not required to be bifurcated, such as those that are clearly and closely related to the host instrument, or hybrid instruments with an embedded derivative that is eligible for one of FAS 133's scope exceptions. This statement is effective for all financial instruments acquired, issued, or subject to a re-measurement, or new basis, event occurring after the beginning of the first fiscal year that begins after September 15, 2006. NRG does not expect this guidance to materially affect the Company's consolidated financial position, results of operations or statement of cash flows.

In July 2006, the FASB issued FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*, or FIN 48. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements tax positions taken or expected to be taken on a tax return, including a decision as to whether to file or not to file in a particular jurisdiction. FIN 48 is effective for fiscal years beginning after December 15, 2006. Changes in net assets as a result of the adoption of FIN 48, if any, are to be accounted for as an adjustment to retained earnings. NRG is currently assessing the impact of FIN 48 on its consolidated financial position.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* or SFAS 157. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. NRG is currently assessing the impact of SFAS 157 on its consolidated financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106 and 132 (R), or SFAS 158.* This statement requires an employer that sponsors one or more single-employer defined benefit plans to recognize the funded status of a benefit plan in its statement of financial position with an offset to other comprehensive income, and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. This statement is effective for financial statements of issuers of publicly traded equity securities for the end of the first fiscal year ending after December 15, 2006. NRG does not expect this guidance to materially affect the Company's consolidated financial position.

Note 2 — Comprehensive Income/(Loss)

(In millions)	Three months ended September 30 2006	Three months ended September 30 2005	Nine months ended September 30 2006	Nine months ended September 30 2005
Net Income/(Loss)	$ 422	$ (27)	$ 651	$ 20
Changes in pension liability, net of tax	7	—	7	—
Unrealized gain/(loss) from derivative activity, net of tax	28	(296)	332	(382)
Foreign currency translation adjustment	(2)	—	35	(50)
Other comprehensive income/(loss), net of tax	$ 33	$ (296)	$ 374	$ (432)
Comprehensive income/(loss)	$ 455	$ (323)	$ 1,025	$ (412)

Accumulated other comprehensive income/(loss) for the nine months ended September 30, 2006 was as follows:

(In millions) As of September 30	2006
Accumulated other comprehensive loss as of December 31, 2005	$ (205)
Changes in pension liability, net of tax	7
Unrealized gain from derivative activity, net of tax	332
Foreign currency translation adjustments	35
Accumulated other comprehensive income as of September 30, 2006	$ 169

Note 3 — Business Acquisitions and Dispositions

Acquisition of Texas Genco LLC and Related Financing

On February 2, 2006, NRG acquired Texas Genco LLC pursuant to an Acquisition Agreement dated September 30, 2005. As such, the results of Texas Genco LLC have been included in NRG's consolidated financial statements since February 2, 2006. The purchase price of approximately $6.2 billion consisted of approximately $4.4 billion in cash, the issuance of approximately 35.4 million shares of NRG's common stock valued at approximately $1.7 billion and acquisition costs of approximately $0.1 billion. The value of NRG's common stock issued to the Sellers was based on NRG's average stock price immediately before and after the closing date of February 2, 2006. The acquisition also included the assumption of approximately $2.7 billion of Texas Genco LLC debt. Texas Genco LLC is now a wholly-owned subsidiary of NRG, and is being managed and accounted for as a separate business segment referred to as NRG Texas.

The acquisition of Texas Genco LLC and related financing activities were funded at closing with a combination of (i) cash proceeds received upon the issuance and sale in a public offering of 20,855,057 shares of NRG's common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $1.2 billion aggregate principal amount of 7.25% Senior Notes due 2014 and $2.4 billion aggregate principal amount of 7.375% Senior Notes due 2016; (iii) cash proceeds received upon the issuance and sale in a public offering of 2,000,000 shares of mandatory convertible preferred stock at a price of $250 per share; (iv) funds borrowed under a new senior secured credit facility consisting of a $3.6 billion term loan facility, a $1.0 billion revolving credit facility and a $1.0 billion synthetic letter of credit facility; and (v) cash on hand.

Like the rest of NRG, NRG Texas is a wholesale power generator whose principal business is selling electric wholesale power produced by power plants to wholesale purchasers such as retail electric providers, power trading organizations and other power generation companies. NRG Texas is the second-largest generation company in the ERCOT market and the largest owner of power plants in the Houston area. As of September 30, 2006, NRG Texas operated 52 generating units at nine power generation plants, including an undivided 44% interest in two nuclear generation units at STP. The aggregate net generation capacity at NRG Texas is approximately 10,800 MW, which includes approximately 5,300 MW of low marginal cost solid fuel and nuclear powered baseload plants.

The acquisition of Texas Genco LLC was accounted for using the purchase method of accounting and, accordingly, the purchase price was allocated to the assets acquired and liabilities assumed based on the estimated fair value of such assets and liabilities as of February 2, 2006. The excess of the purchase price over the fair value of the net tangible and identified intangible assets acquired was recorded as goodwill. The allocation of the purchase price may be adjusted if additional information on known contingencies existing at the date of acquisition becomes available within one year after the acquisition, and longer for certain income tax items. Changes in the allocation between the assessed goodwill and plant or other intangibles would result in a change in non-cash amortization expense.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of the acquisition.

(In millions)	As of February 2, 2006
Assets	
Current and non-current assets	$ 832
Coal inventory	33
In-market contracts	
Power contracts	39
Water contracts	64
Coal contracts	100
Nuclear fuel contracts	48
SO_2 emission allowances	530
NOx emission allowances	320
Property, plant and equipment	9,318
Deferred tax asset	1,560
Goodwill	1,555
Total assets acquired	14,399
Liabilities	
Current and non-current liabilities	937
Pension and post-retirement liability	213
Out-of-market contracts:	
Coal	150
Gas swaps	472
Power contracts	2,100
Deferred tax liability	1,560
Long term debt	2,735
Total liabilities assumed	8,167
Net assets acquired	$ 6,232

NRG is still in the process of finalizing the value of the tax basis of the assets and liabilities acquired which may affect the deferred tax balances with any changes to the tax basis values affecting the final balance of goodwill. NRG is also in the process of reviewing the estimated remaining useful lives for NRG Texas's fixed assets, and when finalized, this may affect the amount of depreciation expense NRG will recognize.

The following table summarizes the change in the value of goodwill during the six month period ended September 30, 2006:

(In millions)	
Goodwill balance at March 31, 2006	$ 2,748
Increase in fixed assets per valuation	(888)
Net decrease in intangibles and other contracts per valuation	319
Adjustment to deferred tax assets and liabilities	(624)
Impact to goodwill due to changes in valuation	(1,193)
Goodwill balance at September 30, 2006	$ 1,555

The changes in the fair value for fixed assets, identifiable intangibles and deferred taxes are due to several factors, including the following:

- Adjustments to the forecasted projected price of electricity, coal and emission allowances;
- The tax basis of the assets and liabilities acquired are more accurate, although still subject to revision; and
- More precise information with respect to identifiable tangible and intangibles assets.

Currently, NRG has valued goodwill at approximately $1.6 billion, with the appraisal of Property, Plant and Equipment increasing its fair value, compared to Texas Genco LLC's historical cost, by approximately $5.8 billion. If the remaining goodwill balance is indicative of a further increase in value of depreciable property plant and equipment, depreciation expense for the three months and nine months ended September 30, 2006 would increase by approximately $20 million and $55 million, respectively, reducing income from continuing operations before tax for the three and nine month period ended September 30, 2006 to approximately $588 million and $857 million, respectively.

Acquisition of Remaining 50% interest in WCP

On December 27, 2005, NRG entered into purchase and sale agreements for projects co-owned with Dynegy, Inc, or Dynegy, with these agreements consummated March 31, 2006. Under the agreements NRG acquired Dynegy's 50% ownership interest in WCP (Generation) Holdings, Inc., or WCP, for $205 million and NRG became the sole owner of WCP's 1,808 MW of generation capacity in Southern California. In addition, NRG sold to Dynegy its 50% ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. NRG sold Rocky Road for a sale price of $45 million, thus paying Dynegy a net purchase price of $160 million at closing. Prior to the purchase, NRG had an existing investment in WCP accounted for as an unconsolidated equity method investment, or Original Investment.

The acquisition of the remaining 50% interest in WCP, or New Investment, was accounted for as a step acquisition since the Original Investment was transacted in a prior period. As a result, the book value of the Original Investment and the purchase price of the New Investment were determined and allocated separately. The value of the Original Investment was based on its book value of approximately $159 million at the date of the New Investment.

The value of the New Investment was allocated based on the estimated fair value of assets acquired and liabilities assumed as of March 31, 2006. The preliminary purchase price allocation reflected an excess of fair value of the net assets acquired over the purchase price of the New Investment, which resulted in negative goodwill of approximately $63 million. The negative goodwill was subsequently allocated as a reduction to the fair value of WCP's fixed assets. Once the WCP asset appraisals are final, the purchase price allocation may change from the amounts included herein based on the results of appraisal, changes in forecasted prices and an analysis of the income tax effect on the acquisition.

The following summarizes the preliminary purchase price and allocation impact of the WCP acquisition as of March 31, 2006:

		New Investment			
(In millions)	**Original Investment**	**Fair Value before Negative Goodwill Allocation**	**Allocation of Negative Goodwill**	**Fair Value after Negative Goodwill Allocation**	**Preliminary Purchase Price Allocation**
Current assets	$ 148	$ 152	$ —	$ 152	$ 300
Property, plant and equipment	24	127	(57)	70	94
Intangible assets	2	14	(6)	8	10
Other non-current assets	—	8	—	8	8
Current liabilities	(12)	(12)	—	(12)	(24)
Non-current liabilities	(3)	(21)	—	(21)	(24)
Negative goodwill	—	(63)	63	—	—
Total Equity	$ 159	$ 205	$ —	$ 205	$ 364

Supplemental Pro Forma Information

The following unaudited pro forma information represents the results of operations as if NRG, NRG Texas and WCP had combined at the beginning of the respective reporting periods. The unaudited pro forma information is not indicative of what the combined company's result of operations would have been had the companies been combined prior to the respective reporting periods or of future results of the combined operations.

	Three months ended September 30	Nine months ended September 30	
(In millions)	**2005**	**2006**	**2005**
Operating revenues	$ 1,625	$ 4,738	$ 3,942
Net income	175	325	363
Earnings per share — Basic	1.43	2.14	2.88
Earnings per share — Diluted	1.31	1.85	2.65
Weighted average number of shares outstanding — Basic	118.9	134.4	121.3
Weighted average number of shares outstanding — Diluted	129.4	155.4	131.8

The pro forma net income for the nine months ended September 30, 2006 reflects the following nonrecurring expenses incurred by Texas Genco LLC before February 2, 2006:

(In millions)	
Equity compensation costs incurred due to immediate vesting of equity compensation awards under change of control provisions	$ 271
Professional fees and other acquisition-related costs	61
Total	$ 332

Other Business Events

Resource Recovery – On August 31, 2006, NRG signed an agreement to sell its Newport and Elk River Resource Recovery facilities, its Becker Ash Disposal facility, and its ownership interest in NRG Processing Solutions LLC, to Resource Recovery Technologies, LLC for total proceeds of approximately $26 million, subject to customary purchase price adjustments. The transaction is expected to close in the fourth quarter 2006, and is subject to customary approvals by the Minnesota Pollution Control Agency and other contractual partners.

Flinders — On August 30, 2006, NRG announced the completion of the sale of its 100% owned Flinders power station and related assets or Flinders, located near Port Augusta, Australia, which consists of two coal-fueled plants – Northern and Playford totaling 760 gross MW, to Babcock & Brown Power Pty, a subsidiary of Babcock & Brown, a global investment and advisory firm. Proceeds from the sale were approximately $242 million (AU$317 million). The sale resulted in the elimination of approximately of approximately $370 million (AU$485 million) of consolidated liabilities including approximately $183 million (AU$240 million) of non-recourse debt obligations and approximately $92 million (AU$121 million) in non-current liabilities related to the obligations for the purchase of electricity and the supply of fuel to the Osborne power station that were guaranteed by NRG. NRG recognized an after-tax gain of approximately $61 million from the sale, which is included in the other international segment results.

Padoma — On July 14, 2006, NRG announced the completion of the acquisition of privately-held Padoma Wind Power, LLC, or Padoma, a wind farm developer, whose principals have developed, financed, built and operated wind farms in the U.S. and Europe. Padoma will maintain its headquarters in La Jolla, California and will operate as a subsidiary of NRG. The initial purchase price of $7 million was completely allocated to goodwill and is included as part of NRG's non-generation segment's assets.

Gladstone — On June 8, 2006, NRG announced the sale of the Company's 37.5% equity interest in the Gladstone power station, or Gladstone, and its associated 100% owned NRG Gladstone Operating Services to Transfield Services, an Australia-based provider of operations, maintenance, ownership and asset management services for a purchase price of approximately $178 million (AU$239 million) subject to customary purchase price adjustments, plus assumption of NRG's share of Gladstone's unconsolidated debt and cash of approximately $58 million (AU$ 77 million) and approximately $26 million (AU$35 million), respectively. After-tax cash proceeds are expected to be in excess of $175 million (AU$ 234 million). The sale is pending until NRG satisfies certain conditions, particularly the securing of certain consents and waivers from the other owners of the project, or agrees to complete the sale on alternative terms. NRG is seeking to close the transaction in 2007.

Audrain — On March 29, 2006, NRG completed the sale of Audrain generating station, a gas-fired peaking facility in Vandalia, Missouri, to AmerenUE, a subsidiary of Ameren Corporation. The proceeds from the sale were $115 million, plus AmerenUE's assumption of $240 million of non-recourse capital lease obligations and assignment of a $240 million note receivable. NRG recorded a pre-tax gain of $15 million.

As discussed in Note 4 below, the activities of Resource Recovery, Flinders and Audrain have been classified as discontinued operations.

Note 4 — Discontinued Operations

NRG has classified certain business operations, and gains/losses recognized on sale, as discontinued operations for businesses that were sold or have met the required criteria for such classification. The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued.

SFAS 144, requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, NRG's management considered cash flow analysis and offers related to the assets and businesses. This amount is included in income/loss from discontinued operations, net of income taxes in the accompanying condensed consolidated statements of operations. In accordance with SFAS 144, assets held for sale will not be depreciated commencing with their classification as such.

The assets and liabilities reported in the balance sheet as of December 31, 2005 as discontinued operations represent disposed operations of entities discussed in Note 3. For the three and nine months ended September 30, 2006 the after-tax gains recognized on the sale of discontinued operations were approximately $61 million and $71 million, respectively, and approximately $11 million was recognized for the three and nine months ended September 30, 2005.

For the three and nine months ended September 30, 2006, discontinued operations consisted of activity related to Resource Recovery, Flinders and Audrain. For the three and nine months ended September 30, 2005, discontinued operations consisted of activity related to Resource Recovery, Flinders, Audrain, NRG McClain, Northbrook New York, LLC, and Northbrook Energy, LLC.

Summarized results of operations of discontinued operations are as follows:

(In millions)	Three months ended September 30 2006		Three months ended September 30 2005		Nine months ended September 30 2006		Nine months ended September 30 2005	
Operating revenues	$	39	$	79	$	184	$	228
Pre-tax income/(loss) from operations of discontinued operations		(13)		(1)		(9)		11
Income from discontinued operations, net of income taxes		49		10		63		24

Note 5 — Write Downs and Gains/(Losses) on Sales of Equity Method Investments

Write downs and gains/(losses) on sales of equity method investments recorded in the condensed consolidated statement of operations include the following:

(In millions)	Three months ended September 30 2006		Three months ended September 30 2005		Nine months ended September 30 2006		Nine months ended September 30 2005	
Latin American funds, or SLAP	$	—	$	—	$	3	$	—
James River		(3)		—		(6)		—
Cadillac		—		—		11		—
Enfield		—		—		—		12
Kendall		—		4		—		4
Total write downs and gains/(loss) on sales of equity method investments	$	(3)	$	4	$	8	$	16

SLAP — On June 30, 2006, NRG, through its wholly-owned entities NRG Caymans-C and NRG Caymans-P completed the sale of its remaining interests in various Latin American power funds to a subsidiary of Australia Post. Total proceeds received were approximately $23 million and a pre-tax gain of approximately $3 million was recognized in the second quarter 2006.

James River — On May 15, 2006, NRG completed the sale of Capistrano Cogeneration Company, a subsidiary of NRG which owned a 50% interest in James River, to Cogentrix. The proceeds from the sale were approximately $8 million. As a result of the sale, NRG recorded a pre-tax loss of approximately $6 million.

Cadillac — On January 1, 2006, NRG sold its 49.5% of its 50% interest in a 38MW biomass fuel generation facility located in Cadillac, Michigan, along with its right to receive Production Tax Credits, or PTCs, through 2009 to Lakes Renewable LLC. In consideration, NRG received an up-front payment of $0.3 million, approximately $4 million in a note receivable and a promissory note equal to the value of its share in future PTCs earned through 2009. The sale was contingent upon the receipt of a favorable private letter ruling from the Internal Revenue Service, or IRS, and accordingly, all consideration was held in escrow. On April 13, 2006, NRG sold its remaining 0.5% share in Cadillac along with its interest in the notes receivable and promissory note to Delta Power for approximately $11 million, resulting in a pre-tax gain of approximately $11 million.

Note 6 — Investments Accounted for by the Equity Method

As of December 31, 2005, NRG had a 50% interest in both MIBRAG and WCP, which were considered significant as defined by applicable SEC regulations. As discussed in Note 3, NRG acquired the remaining 50% interest in WCP on March 31, 2006 and, as such, WCP is no longer accounted for under the equity method of accounting. As of September 30, 2006, the only equity method investment which was considered significant was NRG's 50% interest in MIBRAG.

MIBRAG Summarized Financial Information

For the three and nine months ended September 30, 2006, NRG recorded equity earnings for MIBRAG of $9.3 million and $23.5 million, respectively compared to the three and nine months ended September 30, 2005 equity earnings from MIBRAG of $8.9 million and $16.8 million, respectively.

The following table summarizes the results of operations for MIBRAG, including interests owned by NRG and other parties for the periods shown below:

Results of Operations (in millions)	Three months ended September 30 2006		Three months ended September 30 2005		Nine months ended September 30 2006		Nine months ended September 30 2005	
Operating revenues	$	126	$	114	$	340	$	318
Operating income		22		24		61		50
Net income		18		18		47		34

As discussed in Note 1, NRG adopted EITF 04-6 as of January 1, 2006, which negatively affected NRG's equity investment in MIBRAG. As of December 31, 2005, MIBRAG had an asset valued at approximately $185 million (€157 million), representing stripping costs incurred during mining operations, net of depreciation. Per the guidance of EITF 04-6, the value of such stripping cost is to be eliminated with an offsetting charge to retained earnings. As such, NRG's investment in MIBRAG has been reduced by 50% of the above mentioned asset, approximately $93 million after-tax, with an offsetting charge to retained earnings.

Note 7 — Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, or SFAS 133, requires NRG to recognize all derivative instruments on the balance sheet as either assets or liabilities and to measure them at fair value each reporting period. If certain conditions are met, NRG may be able to designate certain derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives in OCI and subsequently recognize in earnings when the hedged item impacts income. The ineffective portion of a cash flow hedge is immediately recognized in income.

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivative and the hedged item are recorded in current earnings, thus the ineffective portion of a hedging derivative instrument's change in fair value is captured and is immediately recognized into earnings.

For derivatives that are not designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Under the guidelines established per SFAS 133, certain derivative instruments may qualify for the normal purchase and sale exception and are therefore exempt from fair value accounting treatment. SFAS 133 applies to NRG's energy-related commodity contracts, interest rate swaps and foreign exchange contracts.

As the Company engages principally in the trading and marketing of its generation assets, most of NRG's commercial activities qualify for hedge accounting under the requirements of SFAS 133. In order to so qualify, the physical generation and sale of electricity should be highly probable at inception of the trade and throughout the period it is held, as is the case with the Company's baseload plants. For this reason, trades in support of NRG's peaking units will generally not qualify for hedge accounting treatment with any changes in fair value likely to be reflected on a mark-to-market basis in the statement of operations. The majority of trades in support of NRG's baseload units normally qualify for hedge accounting treatment with any change in fair value reflected in the balance sheets as part of OCI.

Derivative Impact to Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS 133 on NRG's OCI balance attributable to hedged derivatives for the three months ended September 30, 2006, net of tax:

(In millions)	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at June 30, 2006	$ 29	$ 79	$ 108
Realized from OCI during the period:			
— Due to realization of previously deferred amounts	—	1	1
Mark-to-market of hedge contracts	92	(65)	27
Accumulated OCI balance at September 30, 2006	$ 121	$ 15	$ 136
Gains expected to be realized from OCI during the next 12 months	$ 26	$ —	$ 26

The following table summarizes the effects of SFAS 133 on NRG's OCI balance attributable to hedged derivatives for the nine months ended September 30, 2006, net of tax:

(In millions)	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at December 31, 2005	$ (204)	$ 8	$ (196)
Realized from OCI during the period:			
— Due to realization of previously deferred amounts	11	(2)	9
Mark-to-market of hedge contracts	314	9	323
Accumulated OCI balance at September 30, 2006	$ 121	$ 15	$ 136

The following table summarizes the effects of SFAS 133 on NRG's OCI balance attributable to hedged derivatives for the three months ended September 30, 2005, net of tax:

(In millions)	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at June 30, 2005	$ (77)	$ (2)	$ (79)
Realized from OCI during the period:			
— Due to realization of previously deferred amounts	55	(2)	53
Mark-to-market of hedge contracts	(359)	10	(349)
Accumulated OCI balance at September 30, 2005	$ (381)	$ 6	$ (375)

The following table summarizes the effects of SFAS 133 on NRG's OCI balance attributable to hedged derivatives for the nine months ended September 30, 2005, net of tax:

(In millions)	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at December 31, 2004	$ 5	$ 2	$ 7
Realized from OCI during the period:			
— Due to realization of previously deferred amounts	53	(1)	52
Mark-to-market of hedge contracts	(439)	5	(434)
Accumulated OCI balance at September 30, 2005	$ (381)	$ 6	$ (375)

Losses of $1 million and $9 million were reclassified from OCI to current period earnings for the three and nine months ended September 30, 2006, respectively, compared to losses of $53 million and $52 million for the three and nine months ended September 30, 2005, respectively, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items were recorded. In addition, for the three and nine months ended September 30, 2006, NRG recorded gains in OCI of approximately $27 million and $323 million, respectively, compared to losses of $349 million and $434 million for the three and nine months ended September 30, 2005, respectively, related to changes in the fair values of derivatives accounted for as cash flow hedges. The balance in OCI relating to SFAS 133 as of September 30, 2006 was an unrecognized gain of approximately $136 million. Over the next 12 months, the Company expects that $26 million of net gains recorded in OCI as of September 30, 2006, will be recognized in earnings.

Derivative Impact to the Statement of Operations

The following table summarizes the pre-tax effects of non-hedge derivatives and derivative activities that do not qualify as hedges on NRG's statement of operations for the three months ended September 30, 2006:

(In millions)	Energy Commodities	Interest Rate	Total
Revenue from majority-owned subsidiaries	$ 183	$ —	$ 183
Equity in earnings of unconsolidated subsidiaries	—	—	—
Cost of operations	—	—	—
Interest Expense	—	—	—
Total statement of operations impact before tax	$ 183	$ —	$ 183

The following table summarizes the pre-tax effects of non-hedge derivatives and derivative activities that do not qualify as hedges on NRG's statement of operations for the nine months ended September 30, 2006:

(In millions)	Energy Commodities	Interest Rate	Total
Revenue from majority-owned subsidiaries	$ 300	$ —	$ 300
Equity in earnings of unconsolidated subsidiaries	—	—	—
Cost of operations	—	—	—
Interest expense	—	3	3
Total statement of operations impact before tax	$ 300	$ (3)	$ 297

With the reclassification of Flinders as a discontinued operation in the second quarter 2006, previously designated cash flow hedges were no longer effective beyond the expected date of the sale and thus the deferred gain previously recorded in OCI of approximately $11 million was recognized as a derivative gain and was included in income from discontinued operations.

The following table summarizes the pre-tax effects of non-hedge derivatives and derivative activities that do not qualify as hedges on NRG's statement of operations for the three months ended September 30, 2005:

(In millions)	Energy Commodities	Interest Rate	Total
Revenue from majority-owned subsidiaries	$ (166)	$ —	$ (166)
Equity in earnings of unconsolidated subsidiaries	—	—	—
Cost of operations	6	—	6
Interest expense	—	—	—
Total statement of operations impact before tax	$ (172)	$ —	$ (172)

The following table summarizes the pre-tax effects of non-hedge derivatives and derivative activities that do not qualify as hedges on NRG's statement of operations for the nine months ended September 30, 2005:

(In millions)	Energy Commodities	Interest Rate	Total
Revenue from majority-owned subsidiaries	$ (252)	$ —	$ (252)
Equity in earnings of unconsolidated subsidiaries	12	—	12
Cost of operations	5	—	5
Interest expense	—	—	—
Total statement of operations impact before tax	$ (245)	$ —	$ (245)

Energy-Related Commodities

As part of NRG's risk management activities, NRG manages its commodity price risk associated with the Company's competitive supply activities and the price risk associated with power sales from NRG's electric generation facilities. In doing so, the Company may enter into a variety of derivative and non-derivative instruments, including the following:

- Forward contracts, which commit NRG to purchase or sell energy commodities in the future.
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.
- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual (notional) quantity.
- Option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- Fixing the price for a portion of anticipated future electricity sales through the use of various derivative instruments including gas swaps at a level that provides an acceptable return on the Company's electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of NRG's power plants.
- Fixing the price of a portion of anticipated energy purchases to supply NRG's load-serving customers.

Ineffectiveness — Ineffectiveness will result from a difference in the relative price movements between a financial instrument and the underlying physical pricing point. If this difference is large enough, it may cause an entity to discontinue the use of hedge accounting. For the three and nine months ended September 30, 2006, NRG's pre-tax earnings were affected by unrealized gains of approximately $78 million and $122 million, respectively, due to the ineffectiveness associated with financial forward contracted electric and gas sales.

Discontinued Hedge Accounting — During the third quarter 2006, due to a relatively mild summer season and expected lower power generation for the remainder of 2006, NRG discontinued cash flow hedge accounting for certain contracts related to commodity price risk previously accounted for as cash flow hedges. These contracts were originally entered into as hedges of forecasted sales by baseload plants. The decision not to deliver against these contracts was driven by the decline in natural gas and associated power prices making it uneconomical to dispatch the units into the marketplace. As a result, approximately $5 million of previously deferred revenue in OCI was recognized in earnings for the three and nine months ended September 30, 2006.

At September 30, 2006, NRG had hedge and non-hedge energy-related commodity contracts extending through December 31, 2026.

Interest Rates

NRG is exposed to changes in interest rates through the Company's issuance of variable rate and fixed rate debt. In order to manage its interest rate risk, NRG enters into interest-rate swap agreements. In January 2006, in anticipation of the New Senior Credit Facility, NRG entered into a series of forward starting interest rate swaps intended to hedge the variability in cash flows associated with this debt issuance. These transactions were designated as cash flow hedges with any gains/losses deferred on the balance sheet in OCI. In February 2006, with the completion of the sale of the Senior Notes, the Company designated a fixed-to-floating interest rate swap as a hedge of fair value changes in the Senior Notes. This interest rate swap was previously designated as a hedge of NRG's 8% Second Priority Notes which were effectively replaced by the Senior Notes. For the three months ended September 30, 2006, NRG did not recognize any ineffectiveness associated with this hedging relationship. For the nine months ended September 30, 2006, NRG recognized $3 million in ineffectiveness associated with this hedging relationship. NRG does not foresee any ineffectiveness of this hedging relationship in the future.

As of September 30, 2006, all of NRG's interest rate swap arrangements had been designated as either cash flow or fair value hedges. At September 30, 2006, NRG had interest rate derivative instruments extending through June 2019.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, NRG may hedge, or protect those cash flows using available foreign currency hedging instruments. On August 15, 2006, NRG entered into a forward foreign exchange contract to sell AU$300 million in exchange for $229 million and designated it as a fair value hedge. Due to changes in the exchange rate, NRG recognized a loss as of September 30, 2006 of approximately $5 million on its cash balance, with an offsetting gain from derivative income on the related contract. The contract settled on October 16, 2006.

Note 8 — Long-Term Debt

Cash Tender Offer and Consent Solicitation

On December 15, 2005, NRG commenced a cash tender offer and consent solicitation for any and all outstanding $1.1 billion aggregate principal amount of the Company's 8% Second Priority Notes. On that date, NRG also commenced a cash tender offer and consent solicitation for any and all outstanding $1.1 billion aggregate principal amount of Texas Genco LLC and Texas Genco Financing Corp.'s 6.875% senior notes due 2014, or the Texas Genco Notes. The offers to purchase the 8% Second Priority Notes and the Texas Genco Notes were part of NRG's previously announced financing plan in connection with the acquisition of Texas Genco LLC. As of February 2, 2006, NRG had received valid tenders from holders in aggregate principal amount of the 8% Second Priority Notes, representing approximately 99.96% of the outstanding 8% Second Priority Notes, and had received valid tenders from holders of the $1.1 billion in aggregate principal amount of the Texas Genco Notes, representing 100% of the outstanding Texas Genco Notes. The purchase price for the 8% Second Priority Notes of approximately $1.2 billion was paid by NRG on February 2, 2006 and included $0.1 billion prepayment penalty which was recorded in debt refinancing expense in NRG's consolidated income statement. The purchase price for the Texas Genco Notes of approximately $1.2 billion was paid by NRG on February 3, 2006 and included $0.1 billion prepayment penalty which was recorded as an acquisition cost for the acquisition of NRG Texas.

New Senior Credit Facility

On January 31, 2006, NRG used proceeds from the issuance of common stock and cash on hand to repay the $446 million outstanding principal balance of NRG's senior secured term loan facility, along with accrued but unpaid interest of approximately $2 million, and terminated the facility. On February 2, 2006, NRG used proceeds from the new debt financing to pay accrued but unpaid fees on the Company's revolving credit facility and funded letter of credit, and terminated those facilities as well.

On February 2, 2006, NRG entered into a new senior secured credit facility, or the New Senior Credit Facility, with a syndicate of financial institutions, including Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley & Co., Inc., as collateral agent, and Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc. as joint lead book-runners, joint lead arrangers and co-documentation agents providing for up to an aggregate amount of $5.575 billion. The New Senior Credit Facility consisted of a $3.575 billion senior first priority secured term loan facility, or the Term Loan Facility, a $1.0 billion senior first priority secured revolving credit facility, or the Revolving Credit Facility, and a $1.0 billion senior first priority secured synthetic letter of credit facility, or the Letter of Credit Facility. The New Senior Credit Facility replaced NRG's then existing senior secured credit facility. The Term Loan Facility matures on February 1, 2013 and will amortize in 27 consecutive equal quarterly installments of 0.25% of the original principal amount of the Term Loan Facility, beginning June 30, 2006, with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011. The Letter of Credit Facility will mature on February 1, 2013 and no amortization will be required in respect thereof. As of September 30, 2006, NRG had approximately $3.557 billion outstanding under the Company's Term Loan Facility. As of September 30, 2006, NRG had issued $858 million under the Company's Letter of Credit Facility and $157 million in letters of credit under the Company's Revolving Credit Facility.

The New Senior Credit Facility is guaranteed by substantially all of NRG's existing and future direct and indirect subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries and certain other subsidiaries. The capital stock of substantially all of NRG's subsidiaries, with certain exceptions for unrestricted subsidiaries, foreign subsidiaries and project subsidiaries has been pledged for the benefit of the New Senior Credit Facility lenders.

The New Senior Credit Facility is also secured by first-priority perfected security interests in substantially all of the property and assets owned or acquired by NRG and its subsidiaries, other than certain limited exceptions. These exceptions include assets of certain unrestricted subsidiaries, equity interests in certain of NRG's project affiliates that have non-recourse debt financing, and voting equity interests in excess of 66% of the total outstanding voting equity interest of certain of NRG's foreign subsidiaries.

The New Senior Credit Facility contains customary covenants, which among other things require NRG to meet certain financial tests, including minimum interest coverage ratio and a maximum leverage ratio on a consolidated basis, and limit NRG's ability to:

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments, loans and advances; and
- pay dividends and/or other payments of subsidiaries.

NRG has the option to prepay the New Senior Credit Facility in whole or in part at any time.

Interest Rate Swaps — In anticipation of the New Senior Credit Facility, in January 2006, NRG entered into a series of forward-setting interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives quarterly the equivalent of a floating interest payment based on a 3-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps is $2.15 billion.

The notional amounts and maturities of each tranche of these swaps are as follows:

Period of swap	Notional Value	Maturity
1 — year	$120 million	March 31, 2007
2 — year	$140 million	March 31, 2008
3 — year	$150 million	March 31, 2009
4 — year	$190 million	March 31, 2010
5 — year	$1.55 billion	March 31, 2011

Senior Notes

On February 2, 2006, NRG completed the sale of (i) $1.2 billion aggregate principal amount of 7.25% senior notes due 2014, or 7.25% Senior Notes, and (ii) $2.4 billion aggregate principal amount of 7.375% senior notes due 2016, or 7.375% Senior Notes, collectively referred to as the Senior Notes. The Senior Notes were issued under an Indenture, dated February 2, 2006, or the Indenture, between NRG and Law Debenture Trust Company of New York, as trustee, or the Trustee, as supplemented by a First Supplemental Indenture, dated February 2, 2006, between NRG, the Guarantors named therein and the Trustee, relating to the 7.25% Senior Notes, and as supplemented by a Second Supplemental Indenture, dated February 2, 2006, between NRG, the Guarantors named therein and the Trustee, relating to the 7.375% Senior Notes. On March 14, 2006, NRG executed a Third Supplemental Indenture and a Fourth Supplemental Indenture, whereby the recently acquired NRG Texas subsidiaries were added as Guarantors. On April 28, 2006, NRG executed a Fifth Supplemental Indenture and a Sixth Supplemental Indenture, whereby the recently acquired WCP subsidiaries were added as Guarantors. The Indentures and the form of notes provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG.

Interest is payable on the Senior Notes on February 1 and August 1 of each year beginning on August 1, 2006 until their maturity dates — February 1, 2014 for the 7.25% Senior Notes and February 1, 2016 for the 7.375% Senior Notes. As of September 30, 2006, NRG had $3.6 billion in principal outstanding under the Company's Senior Notes.

At any time prior to February 1, 2009, NRG may redeem up to 35% of the aggregate principal amount of the series of Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.25% of the principal amount, in the case of the 7.25% Senior Notes, and 107.375% of the principal amount, in the case of the 7.375% Senior Notes. In addition, NRG may redeem the 7.25% Senior Notes and 7.375% Senior Notes at the redemption prices expressed as a percentage of the principal amount redeemed set forth below, plus accrued and unpaid interest on the notes redeemed.

Prior to February 1, 2010 for the 7.25% Senior Notes, or the First Applicable 7.25% Redemption Date, NRG may redeem all or a portion of the 7.25% Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued interest. The premium is the greater of (i) 1% of the principal amount of the note, or (ii) the excess of the principal amount of the note over the following: the present value of 103.625% of the note, plus interest payments due on the note from the date of redemption through the First Applicable 7.25% Redemption Date, discounted at a treasury rate plus 0.50%.

The following table sets forth the premium upon redemption for the 7.25% Senior Notes.

Redemption Period	Premium as defined above
Prior to February 1, 2010	
February 1, 2010 to February 1, 2011	103.625%
February 1, 2011 to February 1, 2012	101.813%
February 1, 2012 and thereafter	100.000%

Prior to February 1, 2011 for the 7.375% Senior Notes, or the First Applicable 7.375% Redemption Date, NRG may redeem all or a portion of the 7.375% Notes at a price equal to 100% of the principal amount plus a premium and accrued interest. The premium is the greater of (i) 1% of the principal amount of the note, or (ii) the excess of the principal amount of the note over the following: the present value of 103.688% of the note, plus interest payments due on the note from the date of redemption through the First Applicable 7.375% Redemption Date, discounted at a Treasury rate plus 0.50%.

The following table sets forth the premium upon redemption for the 7.375% Senior Notes.

Redemption Period	Premium as defined above
Prior to February 1, 2011	
February 1, 2011 to February 1, 2012	103.688%
February 1, 2012 to February 1, 2013	102.458%
February 1, 2013 to February 1, 2014	101.229%
February 1, 2014 and thereafter	100.000%

The Indentures provide for customary events of default which include, among others, nonpayment of principal or interest; breach of other agreements in the Indentures; defaults in failure to pay certain other indebtedness; the rendering of judgments to pay certain amounts of money against NRG and its subsidiaries; the failure of certain guarantees to be enforceable; and certain events of bankruptcy or insolvency. Generally, if an event of default occurs, the Trustee or the Holders of at least 25% in principal amount of the then outstanding series of Senior Notes may declare all of the Senior Notes of such series to be due and payable immediately.

The terms of the Indentures, among other things, limit NRG's ability and certain of its subsidiaries' ability to:

- pay dividends or other payments of subsidiaries;
- incur additional debt; and
- engage in sale and leaseback transactions.

Debt of Discontinued Operations

As discussed in Note 3, on August 30, 2006, NRG announced the completion of the sale of Flinders to Babcock and Brown of Australia. The sale resulted in the elimination of approximately $183 million (AU$240 million) of non-recourse debt.

On March 29, 2006, NRG completed the sale of the Audrain Generating Station to AmerenUE, a subsidiary of Ameren Corporation. Included in the purchase was Ameren's assumption of $240 million of non-recourse capital lease obligations and the assignment of a $240 million note receivable.

NRG Promissory Note

On June 5, 2006, NRG, repaid the principal and interest at maturity on its outstanding $10 million note payable to Xcel Energy.

Debt Related to Capital Allocation Program

During the third quarter 2006, NRG initiated a plan, known as the Capital Allocation Program, to repurchase approximately $750 million of its common stock. Phase I was a $500 million stock repurchase program, which was completed on October 13, 2006. Phase II, as originally announced, was to be an additional $250 million common stock buyback anticipated to commence during the first quarter 2007. NRG has upsized Phase II to $500 million and has accelerated the start to the fourth quarter 2006 and is expected to be completed by the end of the second quarter 2007.

As part of Phase I, the Company formed two wholly-owned unrestricted subsidiaries, NRG Common Stock Finance I, LLC and NRG Common Stock Finance II, LLC, during the third quarter 2006 to repurchase shares of NRG's common stock in the public markets or in privately negotiated transactions. These subsidiaries were funded with a combination of approximately $166 million in cash from NRG and a mix of notes and preferred interests issued to Credit Suisse of approximately $334 million for a total of $500 million. Both the notes and the preferred interests are non-recourse debt to NRG or any of its restricted subsidiaries, with the notes collateralized by the NRG common stock purchased by the subsidiaries. In addition, the assets of these two subsidiaries are not available to the creditors of NRG and its other subsidiaries.

Notes — As of September 30, 2006, total notes issued and outstanding by these two wholly-owned unrestricted subsidiaries were approximately $147 million to Credit Suisse. NRG issued a total of $250 million in notes in Phase I of the Capital Allocation Program that will mature in two tranches: $137.5 million in October 2008 plus accrued interest at an annual rate of 5.45%, and the balance of $112.5 million in October 2009 plus accrued interest at an annual rate of 6.11%.

Preferred Interests — These two wholly-owned unrestricted subsidiaries expect to issue approximately $84 million in preferred interests in connection with Phase I of the Capital Allocation Program. As of September 30, 2006, total preferred interests issued and outstanding was approximately $50 million to Credit Suisse. These preferred interests are classified as a liability per SFAS No. 150, because they embody a fixed unconditional obligation that these two unrestricted subsidiaries must settle. The preferred interests also mature in two tranches: $53 million in October 2008 plus accrued interest at an annual rate of 12.65%, and $31 million in October 2009 plus accrued interest at an annual rate of 13.23%.

Note 9 — Changes in Capital Structure

As of September 30, 2006, NRG had 10,000,000 authorized preferred shares, 2,670,000 of which have been issued and were outstanding. The outstanding preferred shares are comprised of: 420,000 of 4% Preferred Stock, 250,000 of 3.625% Preferred Stock and 2,000,000 of 5.75% Preferred Stock.

Treasury Stock Purchased through Capital Allocation Program

During the third quarter 2006, NRG purchased 6,113,000 of its common stock at a volume-weighted average price of $48.61 per share for a total amount of approximately $297 million through its Capital Allocation Program. At maturity, should NRG's stock price exceed a compound annual growth rate of 20%, beyond a volume-weight average share price determined at the time of repurchase, or the Reference Price, NRG will pay to Credit Suisse the market value of NRG's stock price over the Reference Price in either cash or stock. This difference will be recorded as an increase to the cost of the treasury shares repurchased.

On October 13, 2006, NRG completed the first phase of the Capital Allocation Program, resulting in the repurchase of 10,587,700 of its common stock for approximately $500 million.

5.75% Preferred Stock

On February 2, 2006, NRG completed the issuance of 2,000,000 shares of 5.75% mandatory convertible preferred stock, or the 5.75% Preferred Stock, for net proceeds of $486 million, reflecting an offering price of $250 per share and the deduction of offering expenses and discounts of approximately $14 million. Dividends on the 5.75% Preferred Stock are $14.375 per share per year, and are due and payable on a quarterly basis beginning on March 15, 2006. The 5.75% Preferred Stock will automatically convert into common stock on March 16, 2009, or the Conversion Date, at a rate that is dependent upon the applicable market value of NRG's common stock.

The following table illustrates the conversion rate per share of the 5.75% Preferred Stock:

Applicable Market Value on Conversion Date	Conversion Rate
equal to or greater than $60.45	4.1356
less than $60.45 but greater than $48.75	4.1356 to 5.1282
less than or equal to $48.75	5.1282

Stock issued to the Sellers pursuant to the Acquisition Agreement

On February 2, 2006, pursuant to the Acquisition Agreement, NRG issued 35,406,292 shares of common stock to the Sellers. Of this amount, 19,346,788 shares were issued from treasury and 16,059,504 were newly issued shares. See Note 3 for a further discussion. On August 1, 2006, the lock-up period on the 35,406,292 shares was lifted pursuant to the Investor Rights Agreement between the Sellers and NRG.

Common Stock issued to the public

On January 31, 2006, NRG completed the issuance of 20,855,057 shares of NRG's common stock, for net proceeds of $986 million, reflecting an offering price of $48.75 per share after the deduction of offering expenses and discounts of approximately $31 million.

Second Lien Structure

Before the Acquisition, Texas Genco LLC's capital structure permitted the grant of second priority liens on its assets as security for its obligations under certain long-term power sales agreements and related hedges. The New Senior Credit Facility and the Indentures, which became effective as of February 2, 2006, allow these arrangements to remain in place. In addition, the new debt instruments also permit NRG to grant second priority liens on NRG's other assets in the United States in order to secure obligations under power sales agreements and related hedges, with certain limitations. NRG uses the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under long-term power sales agreements and related hedges. As of September 30, 2006, the net discounted exposure on the hedges that were subject to the second lien structure was approximately $897 million.

Note 10 — Equity Compensation

Incentive Compensation Plans

In December 2004, the FASB issued SFAS No. 123(R) *Share-Based Payment,* a revision to SFAS 123, or SFAS 123(R), which requires NRG to modify the recognition of expense for stock-based compensation in the statement of income. NRG adopted the requirements of SFAS 123(R) effective January 1, 2006 using the modified prospective method. The provisions of SFAS 123(R) did not result in a significant change in NRG's compensation expense because the Company previously recognized compensation expense in the statements of income under SFAS 123. In accordance with SFAS 123(R), NRG estimated a forfeiture rate for each of the Company's awards based on the number of instruments expected to vest rather than recording the actual forfeitures as they occur. The elimination of unearned compensation and amounts previously recognized in income related to the application of the new forfeiture rate to outstanding instruments as of January 1, 2006 were immaterial to NRG's consolidated results of operations.

Long-Term Incentive Plan, or LTIP

As of September 30, 2006, a total of 8,000,000 shares of NRG common stock were authorized for issuance under the LTIP, subject to adjustments in the event of a reorganization, recapitalization, stock split, reverse stock split, stock dividend, and combination of shares, merger or similar change in NRG's structure or outstanding shares of common stock. It is NRG's policy to issue treasury shares upon exercise of a LTIP award. If there are no treasury shares available, unissued shares of common stock will be issued. There were 4,300,489 shares of common stock remaining available for grants under NRG's LTIP as of September 30, 2006.

Non-Qualified Stock Options, or NQSO's

NQSO's granted under the LTIP have a three-year graded vesting schedule beginning on the grant date and become exercisable at the end of this requisite service period. As provided for by SFAS 123(R), for share options with graded vesting issued after January 1, 2006, NRG recognizes compensation costs on a straight-line basis over the requisite service period for the entire award. The maximum contractual term is ten years for approximately 600,000 of NRG's outstanding NQSO's, and six years for the remaining 1.1 million NQSO's. The aggregate intrinsic value for stock options outstanding as of September 30, 2006 and 2005 was approximately $57 million and $19 million, respectively. The aggregate intrinsic value for stock options exercisable as of September 30, 2006 and 2005 was approximately $15 million and $6 million, respectively. The weighted average remaining contractual term for stock options outstanding as of September 30, 2006 and 2005 was approximately six and seven years, respectively. The weighted average remaining contractual term for stock options exercisable as of September 30, 2006 and 2005 was approximately seven and eight years, respectively. Cash received from the exercise of NQSO's and the intrinsic value of exercised NQSO's for the nine months ended September 30, 2006 was $1.1 million and $1.3 million, respectively.

The fair value of stock option grants is estimated on the date of grant using the Black-Scholes option-pricing model. The following table shows the change in the outstanding NQSO balance for the nine months ended September 30, 2005 and 2006:

(In whole, except weighted average data)	Shares	Weighted Average Exercise Price	Weighted Average Grant-Date Fair Value Per Share
Outstanding as of December 31, 2004	962,751	$ 23.15	$ 12.15
Granted	134,000	38.80	13.23
Canceled or Expired	—	N/A	N/A
Exercised	—	N/A	N/A
Outstanding at September 30, 2005	1,096,751	25.06	12.29
Exercisable at September 30, 2005	318,248	23.08	12.13
Outstanding as of December 31, 2005	1,095,251	25.04	12.29
Granted	711,785	47.51	14.18
Canceled or Expired	(92,968)	34.64	12.06
Exercised	(49,832)	21.48	9.77
Outstanding at September 30, 2006	1,664,236	34.22	13.18
Exercisable at September 30, 2006	618,327	24.26	12.44

The fair value of NQSO's issued during the nine months ended September 30, 2006 was based on the following assumptions:

Nine Months Ended September 30,	2006
Weighted –average annualized valuation assumptions	
Expected Volatility	27.95% — 29.64%
Weighted Average Volatility	28.37%
Expected Dividends	—
Expected Term (in years)	4 — 6
Risk Free Rate	4.30% — 5.05%
Forfeiture Rate	8%

NRG uses an expected term of four years for NQSO's based on the simple average of the contractual term and vesting term. Volatility is calculated based on a blended average of NRG and NRG's industry peers' historical two-year stock price volatility data. A forfeiture rate of 8% was calculated for NQSO's based on an analysis of NRG's historical forfeitures, employment turnover, and expected future behavior.

***Restricted Stock Units, or RSU*'s**

RSU's granted under the LTIP fully vest three years from the date of issuance. Compensation expense is based on the fair value of the RSU's which is based on the closing price of NRG common stock on the date of grant multiplied by the number of RSU's granted. Such compensation expense, net of forfeitures, is amortized over the requisite service period. In determining NRG's forfeiture rate, two separate forfeiture rates that best represented the employment termination behavior related to issued RSU's were used, 8% for senior management and 25% for all other employees. The forfeiture rates were based on an analysis of NRG's historical forfeitures, employment turnover, and expected future behavior. The aggregate intrinsic values for non-vested RSU's on September 30, 2006 and 2005 were approximately $61 million and $55 million, respectively.

The following table shows the change in the outstanding RSU balance for the nine months ended September 30, 2005 and 2006:

(In whole except weighted average data)	Shares	Weighted Average Grant-Date Fair Value Per Share
Non-vested as of December 31, 2004	880,994	$ 21.59
Granted	473,850	38.70
Canceled	(56,600)	22.78
Exercised	(1,500)	19.90
Non-vested at September 30, 2005	1,296,744	27.80
Non-vested as of December 31, 2005	1,285,944	27.14
Granted	201,093	47.24
Canceled	(118,500)	28.86
Exercised	(20,000)	38.80
Non-vested at September 30, 2006	1,348,537	$ 30.43

Deferred Stock Units, or DSU's

DSU's granted under the LTIP are fully vested at the date of issuance. Compensation expense recorded is the fair value of the DSU based on the closing price of NRG common stock on the date of grant. For DSU's, compensation expense is fully recognized in the period of grant. The aggregate intrinsic values for DSU's outstanding at September 30, 2006 and September 30, 2005 were approximately $6 million and $5 million, respectively. The aggregate intrinsic values for DSU's converted for the nine months ended September 30, 2006 and 2005 was $0.4 million and $0.3 million, respectively. None of the DSU's issued were either canceled or had expired as of September 30, 2006 and 2005.

The following table shows the change in the outstanding DSU balance for the nine months ended September 30, 2005 and 2006:

(In whole, except weighted average data)	Shares	Weighted Average Grant-Date Fair Value Per Share
Outstanding as of December 31, 2004	60,281	$ 20.31
Granted	68,201	37.54
Conversions	(6,298)	28.20
Outstanding at September 30, 2005	122,184	29.21
Outstanding as of December 31, 2005	122,184	29.21
Granted	25,830	49.22
Conversions	(7,594)	38.75
Outstanding at September 30, 2006	140,420	$ 32.38

Performance Units, or PU's

NRG's outstanding PU's will be paid out after vesting if the average closing price of NRG's common stock for the ten trading days prior to the vesting date, or the Measurement Price, is equal to or greater than the Target Price. The payout for each performance unit will be equal to: (i) one share of common stock, if the Measurement Price equals the Target Price; (ii) a pro-rata amount between one and two shares of common stock, if the Measurement Price is greater than the Target Price but less than the Maximum Price and (iii) two shares of common stock, if the Measurement Price is equal to, or greater than, the Maximum Price.

The Target Price, Maximum Price and vesting period for each PU granted are presented in the following table:

Grant Date	Vesting Period	Outstanding Shares	Target Price	Maximum Price
August 1, 2005	3	36,300	$ 54.50	$ 63.75
January 3, 2006	3	84,500	$ 67.37	79.49
February 3, 2006	3	52,632	$ 66.41	77.67
March 1, 2006	3	25,000	$ 61.82	72.29
May 31, 2006	5	4,400	$ 69.90	81.74
May 31, 2006	3	4,400	$ 69.90	81.74
August 1, 2006	3	1,400	$ 68.27	79.83

The following table shows the change in the outstanding PU balance for the nine months ended September 30, 2005 and 2006:

(In whole, except weighted average data)	Outstanding Shares	Weighted Average Grant-Date Fair Value Per Share
Non-vested as of December 31, 2004	—	—
Granted	45,900	$ 29.87
Canceled	—	—
Non-vested at September 30, 2005	45,900	29.87
Non-vested as of December 31, 2005	44,900	$ 29.87
Granted	180,132	35.02
Canceled	(16,400)	32.19
Non-vested at September 30, 2006	208,632	$ 34.13

The fair value of PU's are estimated on the date of grant using a Monte Carlo simulation model. Volatility is calculated based on a blended average of NRG and NRG's industry peers' two-year historical stock price volatility data. The aggregate intrinsic value for PU's outstanding as of September 30, 2005 and 2006 were approximately $2 million and $9 million, respectively.

Significant assumptions used in the fair value model during the period with respect to PU's are summarized below:

Nine months ended September 30,	2006
Weighted –average annualized valuation assumptions	
Expected Volatility	27.95% — 29.64%
Weighted Average Volatility	28.38%
Expected Dividends	—
Expected Term (in years)	3 — 5
Risk Free Rate	4.30% — 5.04%
Forfeiture Rate	8%

Supplemental Information

The following table summarizes total compensation expense recognized in accordance with SFAS 123(R) for the nine months ended September 30, 2006 and 2005 for each of the four types of awards issued under the LTIP including total non-vested compensation cost not yet recognized is also presented as of September 30, 2006:

(In millions, except weighted average data)	Compensation expense		Total non-vested compensation cost not yet recognized	Weighted average life remaining
	Nine months ended September 30		As of September 30	
Award	2006	2005	2006	2006
NQSO's	$ 3	$ 3	$ 9	1.2
DSU's	1	2	—	—
RSU's	7	5	19	1.2
PU's	2	—	5	2.3
Total	$ 13	$ 10	$ 33	

Note 11 — Earnings Per Share

Basic earnings per common share is computed by dividing net 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 earnings per share is computed in a manner consistent with that of basic earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period.

Dilutive effect for equity compensation — The outstanding NQSO's, non-vested RSU's, DSU's and PU's are not considered outstanding for purposes of computing basic earnings per share. However, these instruments are included in the denominator for purposes of computing diluted earnings per share under the treasury stock method or the if-converted method. The dilutive effect of the potential exercise of outstanding NQSO's, non-vested RSU's and PU's are calculated using the treasury stock method. The dilutive effects of the DSU's are included in the denominator for purposes of computing diluted earnings per share under the if-converted method.

Dilutive effect for equity instruments — NRG's outstanding 4% Preferred Stock, 3.625% Preferred Stock and 5.75% Preferred Stock are not considered outstanding for purposes of computing basic earnings per share. However, these instruments are considered for inclusion in the denominator for purposes of computing diluted earnings per share under the if-converted method.

The reconciliation of basic earnings per common share to diluted earnings per share is shown in the table below:

(In millions, except per share data)	Three months ended September 30 2006		Three months ended September 30 2005		Nine months ended September 30 2006		Nine months ended September 30 2005	
Basic earnings per share								
Numerator:								
Income/(Loss) from continuing operations	$	373	$	(37)	$	588	$	(4)
Preferred stock dividends		(14)		(5)		(38)		(14)
Net income/(loss) available to common stockholders from continuing operations		359		(42)		550		(18)
Discontinued operations, net of income tax expense		49		10		63		24
Net income/(loss) available to common stockholders	$	408	$	(32)	$	613	$	6
Denominator:								
Weighted average number of common shares outstanding		136.2		83.5		130.3		85.9
Basic earnings per share:								
Income/(Loss) from continuing operations	$	2.64	$	(0.51)	$	4.22	$	(0.21)
Discontinued operations, net of income tax expense		0.36		0.12		0.48		0.28
Net income/(loss)	$	3.00	$	(0.39)	$	4.70	$	0.07
Diluted earnings per share								
Numerator:								
Net income/(loss) available to common stockholders from continuing operations	$	359	$	(42)	$	550	$	(18)
Add preferred stock dividends for dilutive preferred stock		11		—		32		—
Adjusted income/(loss) from continuing operations		370		(42)		582		(18)
Discontinued operations, net of tax		49		10		63		24
Net income/(loss) available to common stockholders	$	419	$	(32)	$	645	$	6
Denominator:								
Weighted average number of common shares outstanding		136.2		83.5		130.3		85.9
Incremental shares attributable to the issuance of non-vested RSU's (treasury stock method)		0.9		—		0.8		—
Incremental shares attributable to the assumed conversion of DSU's (if-converted method)		0.1		—		0.1		—
Incremental shares attributable to the issuance of non-vested NQSO's (treasury stock method)		0.5		—		0.5		—
Incremental shares attributable to the assumed conversion of convertible preferred stock (if-converted method)		20.8		—		19.6		—
Total dilutive shares		158.5		83.5		151.3		85.9
Diluted earnings per share:								
Income/(Loss) from continuing operations	$	2.34	$	(0.51)	$	3.85	$	(0.21)
Discontinued operations, net of tax		0.31		0.12		0.41		0.28
Net income/(loss)	$	2.65	$	(0.39)	$	4.26	$	0.07

For the three and nine months ended September 30, 2006, options to purchase 40,364 and 620,985, respectively, of shares of common stock were not included in the computation because the effect would have been anti-dilutive.

For the three and nine months ended September 30, 2005, none of NRG's outstanding convertible preferred shares were included in the computation of diluted earnings per share because the effect would have been anti-dilutive.

Note 12 — Segment Reporting

NRG's identified reportable segments are primarily based on geographic areas, both domestic and foreign. On February 2, 2006 NRG acquired Texas Genco LLC now referred to as NRG Texas creating a new segment of operations — Wholesale Power Generation — Texas.

As of December 31, 2005, interest bearing intercompany debt was issued to certain subsidiaries in the Northeast and South Central segments that resulted in increased interest expense. This reduced the segments' net income for the three and nine months ended September 30, 2006, by $15 million and $49 million for the Northeast segment and $7 million and $23 million for the South Central segment, respectively. During the third quarter 2005, such interest expense was immaterial to both segments.

	Three months ended September 30, 2006										
	Wholesale Power Generation							All Other			
(In millions)	Texas	Northeast	South Central	West	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
Operations											
Operating revenues	$ 1,151	$ 501	$ 165	$ 59	$ 6	$ —	$ 45	$ —	$ 38	$ 35	$ 2,000
Depreciation and amortization	104	22	15	—	3	—	1	—	3	—	148
Equity in earnings of unconsolidated affiliates	—	—	—	3	—	5	9	—	—	—	17
Income/(Loss) from continuing operations before income taxes	480	150	24	13	(7)	6	21	(1)	2	(80)	608
Net income/(loss) from continuing operations	445	150	24	13	(6)	5	17	(1)	(1)	(273)	373
Net income/(loss) from discontinued operations, net of income taxes	—	—	—	—	—	(10)	61	(2)	—	—	49
Net income/(loss)	$ 445	$ 150	$ 24	$ 13	$ (6)	$ (5)	$ 78	$ (3)	$ (1)	$ (273)	$ 422
Total assets	$ 12,717	$ 1,583	$ 895	$ 201	$ 222	$ 180	$ 1,058	$ 28	$ 1,591	$ 1,246	$ 19,721

	Three months ended September 30, 2005									
	Wholesale Power Generation						All Other			
(In millions)	Northeast	South Central	West	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
Operations										
Operating revenues	$ 439	$ 175	$ 1	$ 6	$ —	$ 41	$ —	$ 42	$ (17)	$ 687
Depreciation and amortization	19	16	—	2	—	1	—	2	1	41
Equity in earnings of unconsolidated affiliates	—	—	7	7	6	9	—	—	—	29
Income/(Loss) from continuing operations before income taxes	4	(8)	6	(2)	6	22	—	13	(68)	(27)
Net income/(loss) from continuing operations	4	(8)	6	(2)	5	17	(1)	11	(69)	(37)
Net income/(loss) from discontinued operations, net of income taxes	—	—	—	(1)	(1)	—	12	—	—	10
Net income/(loss)	$ 4	$ (8)	$ 6	$ (3)	$ 4	$ 17	$ 11	$ 11	$ (69)	$ (27)

(In millions)	Texas (a)	Northeast	South Central	West (b)	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	Nine months ended September 30, 2006										
	Wholesale Power Generation						All Other				
Operations											
Operating revenues	$ 2,498	$ 1,196	$ 431	$ 108	$ 7	$ —	$ 131	$ —	$ 126	$ (18)	$ 4,479
Depreciation and amortization	309	66	45	1	7	—	2	—	9	4	443
Equity in earnings of unconsolidated affiliates	—	—	—	2	2	17	25	—	—	—	46
Income/(Loss) from continuing operations before income taxes	765	333	53	17	53	17	61	(1)	19	(405)	912
Net income/(loss) from continuing operations	719	333	53	19	53	14	47	(1)	13	(662)	588
Net income/(loss) from discontinued operations, net of income taxes	—	—	—	—	9	(11)	61	4	—	—	63
Net income/(loss)	$ 719	$ 333	$ 53	$ 19	$ 62	$ 3	$ 108	$ 3	$ 13	$ (662)	$ 651

(a) For the period February 2, 2006 to September 30, 2006.

(b) Includes results of WCP for the period April 1, 2006 to September 30, 2006.

(In millions)	Northeast	South Central	West	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	Nine months ended September 30, 2005									
	Wholesale Power Generation					All Other				
Operations										
Operating revenues	$ 1,087	$ 401	$ 1	$ 12	$ —	$ 123	$ —	$ 119	$ (20)	$ 1,723
Depreciation and amortization	56	46	—	5	—	3	—	8	3	121
Equity in earnings of unconsolidated affiliates	—	—	19	10	18	35	—	—	—	82
Income/(Loss) from continuing operations before income taxes	76	(6)	15	(14)	18	91	(2)	21	(179)	20
Net income/(loss) from continuing operations	76	(6)	15	(16)	14	78	(3)	18	(180)	(4)
Net income from discontinued operations, net of income taxes	—	—	—	2	4	—	18	—	—	24
Net income/(loss)	$ 76	$ (6)	$ 15	$ (14)	$ 18	$ 78	$ 15	$ 18	$ (180)	$ 20

Note 13 — Income Taxes

Income tax expense for the three and nine months ended September 30, 2006 was $235 million and $324 million, respectively, compared to income tax expense of $10 million and $24 million, respectively, for the corresponding periods in 2005. The income tax expense for the nine months ended September 30, 2006 included domestic tax expense of $307 million and foreign tax expense of $17 million. The income tax expense for the nine months ended September 30, 2005 included domestic tax expense of $6 million and foreign tax expense of $18 million.

A reconciliation of the U.S. statutory rate to NRG's effective tax rate from continuing operations for the nine months ended September 30, 2006 and 2005 is as follows:

(In millions except rate data)	Nine months ended September 30 2006	2005
Income From Continuing Operations Before Income Taxes	$ 912	$ 20
Tax at 35%	319	7
State taxes	47	(4)
Valuation allowance	2	20
Disputed claims reserve	(29)	—
Foreign operations	(23)	(11)
Permanent differences including subpart F income	8	12
Income Tax Expense	$ 324	$ 24
Effective income tax rate	35.5%	120.0%

The effective income tax rate for the nine months ended September 30, 2006 and 2005 differs from the U.S. statutory rate of 35% due to a current tax benefit, a property basis difference relating to disbursements from the disputed claims reserve, subpart F income and dividends, and earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate.

Deferred tax assets and valuation allowance

Net deferred tax balance — For the nine months ended September 30, 2006, NRG's domestic net deferred tax asset decreased by $476 million resulting in a domestic net deferred tax asset of $280 million. However, due to an assessment of positive and negative evidence, including projected capital gains and available tax planning strategies, NRG believes that it is more likely than not that a benefit will not be realized on $432 million of domestic tax assets, thus a valuation allowance has remained, resulting in a domestic net deferred tax liability of $152 million.

As a result of the reduction in NRG's domestic net deferred tax assets, the Company's domestic valuation allowance was also reduced. In accordance with SOP 90-7, this movement reduced intangibles by $219 million and reduced NRG's tax expense by $8 million for the nine months ended September 30, 2006. As a result of losses incurred at some of NRG's foreign locations, the Company established approximately $10 million of additional foreign valuation allowances. Therefore, as of September 30, 2006, a valuation allowance of $508 million remained against NRG's total domestic and foreign net deferred tax assets.

Acquisition of NRG Texas — On a preliminary basis, NRG established a deferred tax asset of $1.575 billion and $1.560 billion of deferred tax liabilities in purchase accounting as a result of the acquisition of NRG Texas.

NOL carryforwards — As of September 30, 2006, the Company had NOL carryforwards available for federal income tax purposes of $271 million that will expire through 2026, including $15 million of NOL which is eligible for carryback to prior periods.. In addition, NRG has cumulative foreign NOL carryforwards of $270 million that do not have an expiration date.

Note 14 — Benefit Plans and Other Postretirement Benefits, or OPEB

Substantially all employees hired prior to December 5, 2003 were eligible to participate in NRG's defined benefit pension plans. NRG initiated a noncontributory, defined benefit pension plan effective January 1, 2004, with credit for service from December 5, 2003. In addition, NRG provides postretirement health and welfare benefits (health care and death benefits) for certain groups of employees. Generally, these are groups that were acquired in recent years and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements. As of September 30, 2006, NRG had contributed $39 million of the estimated $58 million expected to be contributed to NRG's pension plans in 2006.

As a result of the acquisition of NRG Texas, NRG assumed responsibility for the assets and liabilities of the NRG Texas pension and retiree welfare plans. This pension plan is a noncontributory defined benefit pension plan that provides cash balance benefits based on all years of service to employees who were employed prior to January 1, 2005. In addition, employees who were hired prior to 1999 are also eligible for grandfathered benefits under a final average pay formula. In most cases, the benefits under the grandfathered formula will be frozen by December 31, 2008.

The NRG Texas employees are also covered under an unfunded postretirement health and welfare plan. Each year, employees receive a fixed credit of $750 to their account plus interest. Certain grandfathered employees will receive additional credits through 2008. At retirement, the employees may use their accounts to purchase retiree medical and dental benefits from NRG. NRG's costs are limited to the amounts earned in the employee's account; all other costs are paid by the participant. The net periodic pension cost relating to the NRG Texas defined benefit plan for the three and nine months ended September 30, 2006 was $3 million and $8 million, respectively and $1 million for the nine months ended September 30, 2006 for its other postretirement benefits plans. The net periodic expense related to NRG Texas's other postretirement benefit plans for the three months ended September 30, 2006 was immaterial. These amounts are included in the tables below.

Components of Net Periodic Benefit Cost

The components of net pension and postretirement benefit costs were as follows:

	Defined Benefit Pension Plans			
	Three months ended September 30		Nine months ended September 30	
(In millions)	**2006**	**2005**	**2006**	**2005**
Service cost benefits earned	$ 4	$ 2	$ 13	$ 8
Interest cost on benefit obligation	4	1	12	3
Expected return on plan assets	(2)	—	(5)	—
Net periodic benefit cost	$ 6	$ 3	$ 20	$ 11

	Other Postretirement Benefits Plans			
	Three months ended September 30		Nine months ended September 30	
(In millions)	**2006**	**2005**	**2006**	**2005**
Service cost benefits earned	$ 1	$ —	$ 2	$ 1
Interest cost on benefit obligation	1	1	3	2
Net periodic benefit cost	$ 2	$ 1	$ 5	$ 3

Note 15 — Commitments and Contingencies

Lease Commitments

With the acquisition of Texas Genco LLC, NRG's operating lease commitments increased significantly. This increase was primarily due to the anticipated commencement of leases for 2,695 railcars over the next two years. As of September 30, 2006, approximately 810 of the railcars had been delivered and were under lease for future commitments of approximately $91 million, all relating to NRG Texas.

Coal, Gas and Transportation Commitments

As a result of the acquisition of Texas Genco LLC, NRG's coal, lignite, and gas purchase and transportation commitments have increased significantly. Future minimum payments under these agreements relating to NRG Texas for the following years are as follows:

Year	**(In millions)**
October 1, 2006 — December 31, 2006	$ 185
2007	730
2008	715
2009	719
2010	440
Thereafter	2,152
Total	$ 4,941

Legal Issues

Set forth below is a description of the Company's material legal proceedings. Pursuant to the requirements of SFAS 5, *Accounting for 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 is reasonably estimable. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments could occur, there can be no certainty that NRG may not ultimately incur charges in excess of presently recorded reserves. A future adverse ruling or unfavorable development could result in future charges which could have a materially adverse effect on NRG's consolidated financial position, results of operations or cash flows.

With respect to a number of the items listed below, management has determined that a loss is not probable or the amount of the loss is not reasonably estimable, or both. In some cases, management is not able to predict with any degree of substantial certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed each of these 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. Management's judgment may, as a result of facts arising prior to resolution of these matters or other factors prove inaccurate and investors should be aware that such judgment is made subject to the uncertainty of litigation.

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.

NRG believes that it has valid defenses to the legal proceedings and investigations described below and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified below, the Company is unable to predict the outcome of these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company's consolidated financial position, results of operations or cash flows. NRG also has indemnity rights for some of these proceedings to reimburse NRG for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

California Electricity and Related Litigation

NRG, WCP, WCP's four operating subsidiaries, Dynegy, Inc. and numerous other unrelated parties are the subject of numerous lawsuits that arose based on events that occurred in the California power market in 2000 and 2001. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market gaming activities. Certain of these lawsuits originally commenced in 2000 and 2001, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Southern District of California. In December 2002, the district court found that federal jurisdiction was absent and remanded the cases back to state court. On June 22, 2002, the case was again removed to Federal Court and plaintiffs filed a motion to remand which was granted. Defendants appealed to the U.S. Court of Appeals for the Ninth Circuit and it stayed the remand order pending its decision. On December 8, 2004, the Ninth Circuit affirmed the district court in most respects, and on March 3, 2005, the Ninth Circuit denied a motion for rehearing. On May 5, 2005, the case was remanded to California state court, and under a scheduling order, defendants filed their objections to the pleadings. On July 22, 2005, based upon the filed rate doctrine and federal preemption, the court dismissed NRG Energy, Inc. without prejudice, leaving only subsidiaries of WCP remaining in the case. On October 3, 2005, the court sustained defendants' demurrer dismissing the case against all remaining defendants. On December 2, 2005, the plaintiffs filed their notice of appeal from the dismissal with the California State Court of Appeals, Fourth District. Briefs were filed by the plaintiffs on June 16, 2006, and by the defendants on August 30, 2006. Other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers that name WCP and/or subsidiaries of WCP, in addition to numerous other defendants. These complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California's antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several of these proceedings.

On June 28, 2006, Dynegy executed a term sheet agreeing in principle to settle the class action claims in the natural gas anti-trust cases consolidated and pending in state court in San Diego, California. WCP and some of its subsidiaries are named defendants and Dynegy's settlement would include full releases for these entities. The settlement resolves claims by core and non-core California consumers of natural gas for damages arising from or relating to allegations of misreporting of natural gas transactions or wash trading. The settlement was finalized in September 2006 and preliminarily approved by the court. It however excludes similar cases filed by individual plaintiffs which Dynegy continues to defend. Neither WCP and its subsidiaries nor NRG paid any defense costs or settlement funds as Dynegy owed and provided a complete defense and indemnification.

On September 26, 2006, the plaintiffs in *Jerry Egger, et all versus Dynegy Inc., et al,* Case No. 809822, Superior Court of California (filed May 1, 2003) filed a voluntary notice of dismissal. Neither WCP and its subsidiaries nor NRG paid any defense costs as Dynegy owed and provided a complete defense and indemnification.

In August 2006, Dynegy entered into an agreement to settle class action claims by California natural gas resellers and cogenerators. These claims are pending in Nevada federal district court in *"In Re Western States Wholesale Natural Gas Antitrust Litigation"*. WCP and its subsidiaries are named defendants and Dynegy's settlement would include full releases for these entities. The settlement is expected to be submitted to the court for approval by the end of 2006. Neither WCP, it subsidiaries, nor NRG paid any defense costs or settlement funds as Dynegy owed and provided a complete defense and indemnification.

In cases relating to natural gas, Dynegy is defending WCP and/or its subsidiaries pursuant to an indemnification agreement and will be the responsible party for any loss. In cases relating to electricity, Dynegy's counsel is representing it and WCP and/or its subsidiaries with each party responsible for half of the costs and each party responsible for half of any loss.

On May 17, 2006, the U.S. Bankruptcy Court for the Southern District of New York granted NRG's motion to disallow all pre-bankruptcy claims filed against NRG related to the California energy crisis in 2000 and 2001.

On August 2, 2006, the U.S. Court of Appeals for the Ninth Circuit in the case of *Public Utilities Commission of the State of California v. FERC, No. 01-71051* upheld in part and reversed in part several FERC orders and remanded the case back to FERC for further proceedings consistent with the decision. The case arose on a petition for review of a series of FERC orders wherein California sought certain refunds for prices paid for power by consumers and businesses. NRG does not believe it will be impacted by this decision.

FERC Proceedings

There are proceedings in which WCP and WCP subsidiaries are parties, which either are pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the CAISO, CDWR, and the State of California. The CDWR claim involves a February 2002 complaint filed by the State of California demanding that FERC abrogate the CDWR contract between the State and subsidiaries of WCP and seeks refunds associated with revenues collected from CDWR by WCP. In 2003, FERC rejected this demand and subsequently denied rehearing. The case was appealed to the U.S. Court of Appeals for the Ninth Circuit where all briefs were filed and oral argument was held December 8, 2004. Dynegy is indemnified by WCP and WCP is responsible for any loss associated with this CDWR litigation unless any such loss is deemed to have resulted from Dynegy's gross negligence or willful misconduct, in which case any such loss would be shared by the parties equally.

Connecticut Congestion Charges

On November 28, 2001, CL&P sought recovery in the U.S. District Court for Connecticut for amounts it claimed were owed for congestion charges under the October 29, 1999 Standard Offer Services Contract. CL&P withheld approximately $30 million from amounts owed to PMI under contract and PMI counterclaimed. CL&P's motion for summary judgment, which PMI opposed, remains pending. NRG cannot estimate at this time the overall exposure for congestion charges for the term of the contract prior to the implementation of standard market design, which occurred on March 1, 2003; however, the full amount withheld by CL&P has been reserved as a reduction to outstanding accounts receivable.

New York Public Interest Research Group

On October 24, 2005, the U.S. Court of Appeals for the Second Circuit issued its opinion in *New York Public Interest Research Group or NYPIRG v. Stephen L. Johnson; Administrator; U.S. Environmental Protection Agency.* In 2000, the NYSDEC issued a NOV to the prior owner of the Huntley and Dunkirk stations. After an unsuccessful administrative challenge to the stations' Title V air quality permits by NYPIRG, it appealed on October 31, 2003. The Second Circuit held that, during the Title V permitting process for the two stations, the 2000 NOV should have been sufficient for the NYSDEC to have made a finding that the stations were out of compliance. Accordingly, the court stated that the EPA should have objected to the Title V permits on that basis and the permits should have included compliance schedules. All petitions for rehearing before the court were denied. On June 3, 2005, the consent decree among NYSDEC, Niagara Mohawk Power Corporation, or NiMo, and NRG was entered in federal court, settling the substantive issues discussed by the Second Circuit in its decision. NYSDEC is now in the process of incorporating the consent decree obligations into the Huntley and Dunkirk Title V permits so as to make them permit conditions, an action NRG believes is supported by the Second Circuit's decision.

Station Service Disputes

On October 2, 2000, NiMo commenced an action against NRG in New York state court seeking damages related to NRG's alleged failure to pay retail tariff amounts for utility services at the Dunkirk Plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego Plants. On October 8, 2002, by stipulation and order, this action was stayed pending submission to FERC of some or all of the disputes in the action. In a companion action at FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo's petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. On April 22, 2005, FERC denied NiMo's motion for rehearing. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on June 23, 2006, denied the appeal finding that NYISO's station service program that permits generators to self supply their station power needs by netting consumption against production in a month is lawful. As a result, during the second quarter 2006, NRG reduced by $18 million its reserve related to the matter. On October 23, 2006, the D.C. Circuit denied NiMo's petition for rehearing. NRG believes it is adequately reserved.

On December 14, 1999, NRG acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an order finding that, at times when NRG is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration. In July and August 2006, the parties submitted their respective statements of the case to their appointed arbitrators. The neutral arbitrator has yet to be selected. NRG believes it is adequately reserved.

Itiquira Energetica, S.A.

NRG's Brazilian project company, Itiquira Energetica S.A., or Itiquira, the owner of a 156 MW hydro project in Brazil, is in arbitration with the former Engineering, Procurement and Construction, or EPC, contractor for the project, Inepar Industria e Construcoes, or Inepar. The dispute was commenced in arbitration by Itiquira in September 2002 and pertains to certain matters arising under the EPC contract between the parties. Itiquira sought Real 140 million and asserted that Inepar breached the contract. Inepar sought Real 39 million and alleged that Itiquira breached the contract. On September 2, 2005, the arbitration panel ruled in favor of Itiquira, awarding it Real 139 million and Inepar Real 4.7 million. Due to interest accrued from the commencement of the arbitration to the award date, Itiquira's award was increased to approximately Real 227 million (approximately $97 million as of December 31, 2005). Itiquira has commenced the lengthy process in Brazil to execute on the arbitral award. NRG is unable to predict the outcome of this execution process. On December 21, 2005, Inepar's request for clarifications was denied. Due to the uncertainty of the ongoing collection process, NRG is accounting for receipt of any amounts as a gain contingency.

CFTC Trading Litigation

On July 1, 2004, the Commodities Futures Trading Commission, or CFTC, filed a civil complaint against NRG in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act. In May 2004, the U.S. Bankruptcy Court presiding over NRG's chapter 11 bankruptcy reorganization expunged the CFTC's proof of claim. On March 15, 2005, NRG's motion to dismiss was granted by the federal district court. On May 13, 2005, the CFTC filed a notice of appeal with the U.S. Court of Appeals for the Eighth Circuit. On August 2, 2006, the court reversed the district court's dismissal of the CFTC's action against NRG seeking a permanent injunction against future violations of the Commodities Exchange Act. The case was remanded back to the district court for further proceedings consistent with the decision. On November 17, 2004, a bankruptcy court hearing was held on the CFTC's motion to reinstate its expunged bankruptcy claim, and on NRG's motion to enforce the provisions of the NRG plan of reorganization, thereby precluding the CFTC from continuing its federal court action. The bankruptcy court has yet to schedule a hearing or rule on the CFTC's pending motion to reinstate its expunged claim.

Texas Asbestos Litigation

Several of NRG's plants are the subject of lawsuits, primarily commenced in 2001, against numerous defendants by a large number of individuals who claimed personal injury due to alleged exposure to asbestos while working at plant sites in Texas. These are premise-based claims as distinguished from product-based claims. The overwhelming majority of these claimants are third party contractors or sub-contractors who participated in the construction, renovation, and/or repair of various industrial plants, including power plants. As of September 30, 2006, there were 3,386 pending claims. During the third quarter 2006, there were two claims filed, three claims settled, and 33 claims dismissed or otherwise resolved with no payment. For the nine months ended September 30, 2006, there were three claims filed, seven claims settled, and 222 claims dismissed or otherwise resolved with no payment. While ultimate financial responsibility for uninsured losses relating to asbestos claims has been assumed by NRG, CenterPoint Energy has agreed to continue to indemnify such claims to the extent they are covered by insurance maintained by CenterPoint Energy, subject to reimbursement of the costs of such defense from NRG. To date, costs of settlement and defense have not been material and a portion of the payments in respect of these claims has been offset by insurance recoveries.

Disputed Claims Reserve

As part of NRG's plan of reorganization, NRG funded a disputed claims reserve for the satisfaction of certain general unsecured claims that were disputed claims as of the effective date of the plan. Under the terms of the plan, as such claims are resolved, the claimants are paid from the reserve on the same basis as if they had been paid out in the bankruptcy. To the extent the aggregate amount required to be paid on the disputed claims exceeds the amount remaining in the funded claims reserve, NRG will be obligated to provide additional cash and common stock to satisfy the claims. Any excess funds in the disputed claims reserve will be reallocated to the creditor pool for the pro rata benefit of all allowed claims. The contributed common stock and cash in the reserves is held by an escrow agent to complete the distribution and settlement process. Since NRG has surrendered control over the common stock and cash provided to the disputed claims reserve, NRG recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from the balance sheet. Similarly, NRG removed the obligations relevant to the claims from the balance sheet when the common stock was issued and cash contributed.

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company's Chapter 11 plan totaling $25 million in cash and 2,541,000 shares of common stock. As of October 11, 2006, the reserve held approximately $10 million in cash and approximately 692,000 shares of common stock. NRG believes the cash and stock together represent sufficient funds to satisfy all remaining disputed claims.

Bourbonnais Agreements

On January 31, 2006, NRG finalized a stipulation and settlement agreement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001. The stipulation fixes the amount and provides for the allowance of the equipment manufacturer's proof of claim previously filed during NRG's bankruptcy proceeding. The settlement agreement provides for a $6 million payment by NRG to the equipment manufacturer, and the release of all claims NRG Bourbonnais and NRG have for the return of payments made under the 1999 and 2001 turbine purchase agreements. Under the settlement agreement, NRG received certain equipment valued at $55 million as well as a one-year option to purchase new-build equipment for a fixed price. During the first quarter 2006, NRG recorded approximately $67 million of other income associated with the settlement due to reversal of accounts payable totaling $35 million resulting from the discharge of the previously recorded liability, and an adjustment to write up the value of the equipment received to its fair value, resulting in income of approximately $32 million.

Note 16 — Regulatory Matters

With the exception of NRG's thermal and chilled water business and decommissioning responsibilities related to STP, NRG's operations are not regulated operations subject to SFAS 71 and NRG does not record assets and liabilities that result from the regulated ratemaking processes. NRG does operate, however, in a highly regulated industry and the Company is subject to regulation by various federal and state agencies. As such NRG is affected by regulatory developments at both the federal and state level and in the regions in which NRG operates.

Texas Region

As a result of the Acquisition, NRG has become the beneficiary of decommissioning trusts that have been established to provide funding for decontamination and decommissioning of STP in which NRG owns a 44% interest. CenterPoint Energy Houston Electric, LLC, or CenterPoint, and American Electric Power, or AEP, collect, through rates or other authorized charges to their electric utility customers, amounts designated for funding NRG's portion of the decommissioning of the facility. In the event funds from the trusts are inadequate to fund NRG's ownership portion of the actual decommissioning costs, CenterPoint and AEP or their successors will be required to collect through rates or other authorized charges to customers as contemplated by the Texas Utility Code all additional amounts required to fund NRG's obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trust, the excess will be refunded to the ratepayers of CenterPoint, AEP, or their successors. The fair value of the trust assets are reflected as a non-current asset with an associated long-term liability to reflect the future obligation to fund the decommissioning of the facility from the trust assets or to refund or collect additional amounts from the ratepayers of CenterPoint, AEP or their successors.

In addition to the nuclear decommissioning trusts, NRG has recorded asset retirement obligations and liabilities in accordance with SFAS 143. The assets and liabilities were recorded on the respective acquisition dates based on the estimated future costs of decontamination and decommissioning of NRG's 44% interest in STP. The asset is being amortized over the remaining licensing period for STP and is reflected as a component of property, plant and equipment. The Asset Retirement Obligation, or ARO, accretion is being recognized with the associated liability.

As of September 30, 2006, the trust assets had a market value of $331 million. The unamortized portion of the retirement obligation asset was $266 million. The decommission liability was $319 million, and the reserve to fund the decommissioning from the trust assets and payments to or from ratepayers was $278 million. In accordance with SFAS 71, and due to the fact that NRG does not have any economic exposure for these decommissioning responsibilities, changes in the related assets and liabilities are not reflected in the statement of operations. As such, the total carrying value of all assets and all liabilities associated with the decommissioning and the trusts will always be equal.

Northeast Region

New England — On March 7, 2006, a broad group of New England market participants filed a proposed settlement that provides for interim capacity transition payments for all generators in New England for the period starting December 1, 2006 through May 31, 2010, and the establishment of a Forward Capacity Market, or FCM, commencing May 31, 2010. The FCM to be established by the settlement will operate on an annual descending clock forward capacity auction, by which ISO-NE will obtain the installed capacity requirement of New England, which is normally three years in advance. For the Company's Connecticut units subject to RMR Agreements, any transition payment will be credited against the monthly availability payment for those units, resulting in no additional revenues for those units. NRG's other New England generation units are expected to be eligible for the transition payments. On June 16, 2006, FERC issued an order accepting the proposed settlement.

FERC accepted revised RMR agreements for the Devon, Middleton and Montville stations on February 1, 2006, establishing them effective January 1, 2006, and providing for the continued operation of the stations as RMR facilities. The Devon RMR Agreement will terminate ninety days after the commencement of the Locational Forward Reserve Market, or LFRM, but no earlier than January 1, 2007. On May 12, 2006, FERC accepted ISO-NE's Ancillary Service Market Phase II package that includes the LFRM, granting the requested effective date of October 1, 2006, and thus triggering the termination of the Devon RMR Agreement effective January 1, 2007. On October 5, 2006, FERC accepted proposed revisions to the Devon RMR Agreement clarifying that, should the Devon units participate in the LFRM; the units will have to comply with the requirements of that market. Unless terminated earlier, the Middletown and Montville RMR agreements are expected to terminate upon the commencement of the FCM.

On February 15, 2006, NRG reported to FERC and to ISO-NE that for two days in January 2006, after unit 12 at the Devon station had been removed from service for needed maintenance, it was erroneously reported to ISO-NE as available. NRG further reported that when ISO-NE dispatched the Devon units on January 25, 2006, and unit 12 was unable to respond, inaccurate information was provided to ISO-NE. On March 28, 2006, NRG was advised by FERC that it had commenced a preliminary, non-public, informal investigation into the January 25, 2006, ISO-NE dispatch. That same day, FERC also issued to NRG a data request. On April 24, 2006, NRG submitted to FERC an initial response to the data request and made additional submissions during the second and third quarters of 2006. On June 21, 2006, and on October 5, 2006, NRG received supplemental data requests from FERC to which NRG has responded. NRG continues to investigate the matter and is cooperating with FERC and ISO-NE. The outcome of this investigation cannot be predicted at this time.

On October 11, 2006, FERC denied the complaint filed on September 12, 2005 by Richard Blumenthal, Attorney General for the State of Connecticut against ISO-NE that sought to amend the ISO-NE's market rules to require all electric generation facilities not currently operating under an RMR agreement in Connecticut to be placed under cost-of-service rates.

New York — A dispute is ongoing with respect to high prices for spinning reserves, or SR, and non-spinning reserves, or NSR, in the NYISO-administered markets during the period from January 29, 2000 to March 27, 2000. Certain entities have argued that the NYISO acted unreasonably in declining to invoke Temporary Extraordinary Operating Procedures, or TEP, to recalculate prices and that the markets should be resettled for various reasons. In a series of orders, FERC declined to grant the requested relief. On appeal, the U.S. Court of Appeals for the D.C. Circuit, remanded the case back to FERC to further explain its decision not to utilize TEP to remedy certain of these market issues. On March 4, 2005, FERC issued an order reaffirming that (i) the NYISO acted reasonably in not invoking TEP, (ii) NYISO did not violate its tariff, and (iii) refunds should not be granted; this order was reaffirmed on rehearing on November 17, 2005. These orders have subsequently been appealed to the D.C. Circuit which has already issued a briefing order. Resettlement of the market, while viewed as unlikely could have a material financial impact.

On April 19, 2006, a settlement was reached with respect to high prices in the NYISO energy market on May 8 and 9, 2000. At issue were material amounts paid to NRG for power delivered on those dates. As a result of the settlement, NRG will retain the amounts paid to it in 2005 and received additional non-material amounts. The settlement was filed with FERC on May 25, 2006 and on July 12, 2006, FERC issued an order accepting the proposed settlement.

On March 15, 2006, NRG received the results from NYISO Market Monitoring Unit's review of NRG's Astoria plant's 2004 Generating Availability Data System reporting. This audit may result in the resettlement of NRG's capacity revenues from the Astoria facility due to a redetermination of the amount of available capacity. NRG is currently in settlement discussions with the NYISO, and has established a reserve.

West Region

On October 11, 2006, the Nevada Public Utilities Commission, or NPUC, dismissed the Petition for Declaratory Order filed on August 18, 2006, by Nevada Power Company, or NPC, regarding its contract with Saguaro Power, which owns a cogeneration facility in Henderson, Nevada. The Saguaro facility is a Qualifying Facility and sells energy and capacity to NPC pursuant to a long-term contract in accordance with the Public Utility Regulatory Policy Act of 1978. In the petition, NPC sought, among other things, to modify certain provisions of the contract, or in the alternative, terminate the contract which would have harmed the materially affected project financially.

Note 17 — Environmental Matters

The construction and operation of power projects are subject to stringent environmental, safety protection and land use laws and regulation in the U.S. If such laws and regulations become more stringent, or new laws, interpretations or compliance policies apply and NRG's facilities are not exempt from coverage, the Company could be required to make extensive modifications to further reduce potential environmental impacts. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on the Company's operations.

Environmental Capital Expenditures

NRG has estimated that approximately $1.3 billion of environmental capital expenditures will be incurred during the period 2007 through 2012 in order to keep NRG's facilities in compliance with environmental laws, primarily related to installation of particulate, SO_2, NO_X, and mercury controls to comply with CAIR and Clean Air Mercury rules, as well as installation of BTA under the Phase II 316(b) Rule. NRG updates its expected environmental retrofit plan and associated estimates for environmental capital expenditures annually. These plans, including installed equipment and timing as well as cost can be expected to change over time, in some cases materially.

Other Environmental Matters

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws impose strict joint and several liabilities. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial.

Northeast Region

Remedial obligations at the Arthur Kill generating station have been established in discussions between NRG and the NYSDEC and are estimated to be approximately $2 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be also approximately $2 million. NRG may be required to remediate historical coal tar contamination and record a deed restriction on the Astoria property if significant contamination is to remain in place. NRG will implement a remedial action plan over the next eight years to address historical ash contamination at other facilities in the Northeast region. The total estimated cost at these facilities is not expected to exceed $2 million.

As a result of a small 2001 underground fuel line leak at the Company's Vienna Generating Station, NRG submitted a plan for remediation to the Maryland Department of the Environment, or MDE. The MDE has not formally responded. The remediation in connection with this matter is not expected to materially impact NRG's financial results.

In January 2006, NRG 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 a historic captive landfill. NRG is working with the DNREC, through the Voluntary Clean-up Program, to investigate the site. The Company is unable to predict the financial impact at this time.

South Central Region

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request under Section 114 of the CAA from USEPA seeking information primarily related to physical changes made at Big Cajun II and subsequently received a notice of violation, or NOV, based on alleged NSR violations. NRG submitted multiple responses commencing on February 27, 2004 through October 20, 2004. On May 9, 2006, these entities received from the Department of Justice, or DOJ, a notice of deficiency related to their responses to which NRG responded on May 22, 2006. A document review was conducted at Louisiana Generating, LLC's offices by the DOJ during the week of August 14, 2006. Following the review, Louisiana Generating, LLC has forwarded requested copies of certain documents to the DOJ.

West Region

The Asset Purchase Agreements under which NRG acquired the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that Southern California Edison, or SCE, and San Diego Gas & Electric, or SDG&E, as sellers retain liability, and indemnify NRG for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. Having identified existing contamination, SDG&E has agreed to address contamination and is undertaking corrective action at the Encina and San Diego plant sites.

NRG remediated contamination from a 2002 oil leak at the El Segundo Generating Station. Contaminated soils beneath the foundation were left in place, with approval from the Los Angeles Regional Water Quality Control Board, for removal when the building is demolished.

As part of decommissioning the 32nd Street Naval Station combustion turbine facility in San Diego, investigation and remediation of contaminated soils in inaccessible areas may be required in the future. Although NRG is unable to predict the exact financial impact at this time, NRG believes the cost to remediate will not be material.

Note 18 — Guarantees

NRG and its subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of the Company's business activities. Examples of these contracts include asset purchase and sale agreements, commodity sale and purchase agreements, joint venture agreements, operations and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. In many cases, NRG's maximum potential liability cannot be estimated, since some of the underlying agreements contain no limits on potential liability.

Below are the descriptions of material guarantees and should be read in conjunction with the complete descriptions under Note 29 *Guarantees and Other Contingent Liabilities* in NRG's Form 10-K for the fiscal year ended December 31, 2005.

On August 30, 2006, with the completion of the sale of Flinders, NRG guaranteed the payment and performance of the Flinders subsidiaries' obligations under the sale and purchase agreement. Maximum liability of NRG is limited to the sale price of AU$317 million. In addition, with the completion of the sale, existing guarantees and indemnities of NRG related to Flinders were released.

With the acquisition of Texas Genco LLC, NRG assumed several guarantee obligations relating to Texas Genco LLC's entities. Under these guarantees, NRG has guaranteed the payment obligations of NRG Texas LP, formerly known as Texas Genco II LP, under commercial agreements to various parties. Maximum obligations under these guarantees as of September 30, 2006 were approximately $35 million.

On June 1, 2006, NRG, through its wholly-owned entities NRG Caymans C and NRG Caymans P entered into an agreement to sell its investments in Latin America Power entities to a subsidiary of Australia Post. The agreement includes an indemnity from the companies relating to costs incurred by the buyer for breach of representations, warranties or covenants contained in the sale agreement. Liability for these companies is capped at approximately $23 million. No claim for a breach of representations or warranties can be brought after March 31, 2007.

On March 31, 2006, NRG purchased the remaining 50% interest in WCP from Dynegy. In conjunction with the purchase, NRG agreed to indemnify Dynegy, subject to certain caps and limitations, for breach of representations, warranties, covenants, and losses incurred under the CDWR litigation and certain California electricity-related litigation. For further information about the litigation, see Note 15.

On March 28, 2006, NRG executed a guarantee to the benefit of AmerenUE, the purchaser of NRG's Audrain generating assets. Pursuant to this agreement, NRG guaranteed the payment and performance of the Company and its subsidiaries' obligations pursuant to the sale agreement. This guarantee extends to certain claims made within five years of the sale and the Company's maximum exposure under this guarantee is $10 million. In addition to this guarantee, NRG received a $2.75 million payment from the project lenders in consideration for retaining certain pre-closing tax liabilities related to the Audrain project. This payment was recorded within other non-current liabilities on NRG's consolidated balance sheet. In consideration for this payment, NRG agreed to indemnify the project lenders, subject to a $10 million cap for liabilities related to the pre-closing taxes applicable to the Audrain project.

In 2006, NRG executed a guarantee to the benefit each of two counterparties under the railcar lease described in Note 15. These guarantees cover payment and performance obligations of the Company's wholly-owned subsidiary, NRG Texas LP, under the relevant lease documents. NRG does not believe that it will be required to perform under this indemnity.

For the nine months ended September 30, 2006, NRG had net increases to its guarantee obligations under other commercial arrangements of approximately $463 million. These pertain to payment obligations of NRG Power Marketing Inc., or PMI.

Because many of the guarantees and indemnities NRG issues to third parties do not limit the amount or duration of the Company's obligations to perform under them, there exists a risk that NRG may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit NRG's liability exposure, NRG may not be able to estimate what the Company's liability would be until a claim is made for payment or performance, due to the contingent nature of these contracts.

Note 19 — Subsequent Event

On November 3, 2006, NRG announced its intention to enter into a series of transactions that includes (i) the reset of existing out-of-the-money hedges for years 2006 through 2010 to market, (ii) substantial new baseload hedges for the years 2010 and 2011 and, possibly, later years, (iii) the issuance of $1.1 billion of new high yield notes, and (iv) amendments to NRG's Senior Credit Facility, including the increase of the synthetic letter of credit facility by $500 million.

Resetting of Existing Hedges, or Hedge Reset — NRG has entered into amendments of certain existing hedge agreements for the years 2006 through 2010, including hedge agreements with J.Aron & Company. These hedges were gas swaps and power contracts that were acquired as part of the acquisition of Texas Genco LLC, which closed on February 2, 2006. These hedges were entered into by Texas Genco at a time when power and natural gas prices were lower than they are today, and as a result, the hedges obligate NRG to sell power or natural gas at prices significantly below current market prices. Under the amended agreements, NRG has reset the pricing of these hedges to reflect current market prices, and has agreed to pay cash to the hedge counterparties in amounts that reflect a negotiated present value of the difference between the original prices in the hedges and the amended prices. The total amount to be paid to the counterparties is expected to be approximately $1.35 billion.

The Hedge Reset will provide the flexibility through NRG's second lien structure to expand its hedges on baseload generation for an extended period, and will improve the Company's cash flows and credit profile which will contribute to the Company's ability to amend its existing senior credit facility.

New Hedges — NRG has entered into, and will continue to enter into, new forward natural gas swaps contracts for the years 2010 and 2011, in order to hedge future power prices with respect to NRG's baseload power generation facilities in those years. As appropriate market opportunities arise, NRG will extend the hedging program to later years. As a result of these transactions, NRG will be significantly more hedged with respect to its baseload power generation through 2011. NRG's obligations under the New Hedges and Hedge Reset are or will be secured by second liens on substantially all of the assets of NRG and its subsidiaries, pursuant to NRG's existing second lien structure.

Issuance of New High Yield Notes — NRG plans to finance the payments required in order to reset the existing hedges with cash on hand and with proceeds from the issuance of $1.1 billion of new high yield notes.

Amendment of Senior Credit Facility — NRG plans to amend its existing Senior Credit Facility to accomplish, among other things, the following objectives:

- to permit the incurrence of the new debt represented by the new high yield notes;
- to increase the amount of the synthetic letter of credit facility by $500 million, from $1.0 billion to $1.5 billion;
- to increase the Available Amount, and effect a corresponding increase in NRG's restricted payments capacity, by $250 million; and
- to provide additional flexibility to NRG with respect to certain covenants governing or restricting the use of excess cash flow, new investments, new indebtedness and permitted liens.

The amendments to the existing hedges, the issuance of the new high yield notes, and the amendments to the Senior Credit Facility are expected to close by November 21, 2006. NRG has entered into bridge agreements with Merrill Lynch & Co. to assure that it has adequate financing to fund the amounts owed to the hedge counterparties, and Merrill Lynch & Co. has issued a commitment to NRG to refinance its Senior Secured Credit Facility if the desired amendments to the existing facilities cannot be procured.

Impact to Results of Operations — NRG will account for the Hedge Reset as a net settlement of its current hedge positions and a subsequent reestablishment of new hedge positions. The impact of the net settlement will be recorded as a decrease to NRG's consolidated revenues with an offsetting increase in revenues from a reduction in the associated derivative liability and the associated out-of-market power contract balance established upon the Acquisition of NRG Texas.

Note 20 — Condensed Consolidating Financial Information

As of September 30, 2006, the Company had $1.2 billion of 7.25% Senior Notes and $2.4 billion of 7.375% Senior Notes outstanding. These notes are guaranteed by certain of NRG's current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries. Each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of September 30, 2006.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Cabrillo Power I LLC
Cabrillo Power II LLC
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power LLC
El Segundo Power II LLC
GCP Funding Company, LLC
Hanover Energy Company
Huntley Power LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Long Beach Generation LLC
Louisiana Generating LLC
Middletown Power LLC
Montville Power LLC
NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
New Genco GP, LLC
New Genco LP, LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Generation Holdings, Inc.
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Texas LP
NRG Texas LLC
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mid Atlantic Affiliate Services Inc.
NRG Mesquite LLC
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services, LLC
Texas Genco Services, LP
Vienna Operations Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

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, 2006
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
Operating Revenues					
Revenues from majority-owned operations	$ 1,903	$ 96	$ 1	$ —	$ 2,000
Operating Costs and Expenses					
Cost of majority-owned operations	995	63	(3)	—	1,055
Depreciation and amortization	141	6	1	—	148
General, administrative and development	26	4	49	—	79
Total operating costs and expenses	1,162	73	47	—	1,282
Operating Income/(Loss)	741	23	(46)	—	718
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	94	—	480	(574)	—
Equity in earnings of unconsolidated affiliates	2	15	—	—	17
Write downs and losses on sales of equity method investments	(2)	(1)	—	—	(3)
Other income, net	(12)	17	36	(11)	30
Interest expense	(33)	(22)	(110)	11	(154)
Total other income/(expense)	49	9	406	(574)	(110)
Income/(Loss) From Continuing Operations Before Income Taxes	790	32	360	(574)	608
Income tax expense/(benefit)	289	10	(64)	—	235
Income From Continuing Operations	501	22	424	(574)	373
Income/(losses) from discontinued operations, net of income tax expense (benefit)	—	51	(2)	—	49
Net Income	$ 501	$ 73	$ 422	$ (574)	$ 422

(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, 2006
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
Operating Revenues					
Revenues from majority-owned operations	$ 4,218	$ 261	$ —	$ —	$ 4,479
Operating Costs and Expenses					
Cost of majority-owned operations	2,298	178	2	—	2,478
Depreciation and amortization	420	19	4	—	443
General, administrative and development	73	11	136	—	220
Total operating costs and expenses	2,791	208	142	—	3,141
Operating Income/(Loss)	1,427	53	(142)	—	1,338
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	130	—	911	(1,041)	—
Equity in earnings of unconsolidated affiliates	3	43	—	—	46
Write downs and gains/(losses) on sales of equity method investments	(5)	13	—	—	8
Other income, net	14	93	26	(15)	118
Refinancing expense	—	—	(178)	—	(178)
Interest expense	(170)	(47)	(218)	15	(420)
Total other income/(expense)	(28)	102	541	(1,041)	(426)
Income/(Loss) From Continuing Operations Before Income Taxes	1,399	155	399	(1,041)	912
Income tax expense/(benefit)	530	44	(250)	—	324
Income From Continuing Operations	869	111	649	(1,041)	588
Income from discontinued operations, net of income tax expense	—	61	2	—	63
Net Income	$ 869	$ 172	$ 651	$ (1,041)	$ 651

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

NRG Energy, Inc. and Subsidiaries
Condensed Consolidating Balance Sheet
September 30, 2006
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy Inc.	Eliminations(a)	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 36	$ 388	$ 964	$ —	$ 1,388
Restricted cash	1	73	—	—	74
Accounts receivable-trade, net	398	37	(2)	—	433
Inventory	385	12	—	—	397
Deferred income taxes	183	(20)	(104)	—	59
Derivative instruments valuation	956	5	—	—	961
Collateral on deposit in support of energy risk management activities	132	—	—	—	132
Prepayments and other current assets	89	38	737	(650)	214
Current assets — discontinued operations	—	2	11	—	13
Total current assets	2,180	535	1,606	(650)	3,671
Net property, plant and equipment	11,264	406	16	—	11,686
Other Assets					
Investment in subsidiaries	712	—	9,451	(10,163)	—
Equity investments in affiliates	32	287	—	—	319
Notes receivable, less current portion	998	468	4,460	(5,458)	468
Goodwill	1,547	—	—	—	1,547
Intangible assets, net	994	7	—	—	1,001
Intangible assets held-for-sale	53	—	—	—	53
Nuclear decommissioning trust fund	331	—	—	—	331
Derivative instruments valuation	346	—	14	—	360
Deferred income taxes	—	27	—	—	27
Other non-current assets	24	58	162	—	244
Non-current assets — discontinued operations	—	1	13	—	14
Total other assets	5,037	848	14,100	(15,621)	4,364
Total Assets	$ 18,481	$ 1,789	$ 15,722	$ (16,271)	$ 19,721
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 460	$ 93	$ 38	$ (468)	$ 123
Accounts payable	(988)	263	1,003	—	278
Deferred income taxes	—	—	—	—	—
Derivative instruments valuation	901	—	—	—	901
Accrued expenses and other current liabilities	494	63	110	(182)	485
Current liabilities — discontinued operations	—	3	5	—	8
Total current liabilities	867	422	1,156	(650)	1,795
Other Liabilities					
Long-term debt and capital leases	4,460	752	8,072	(5,458)	7,826
Nuclear decommissioning reserve	278	—	—	—	278
Nuclear decommissioning trust liability	319	—	—	—	319
Deferred income taxes	240	(79)	201	—	362
Derivative instruments valuation	342	6	21	—	369
Out-of-market contracts	2,128	—	—	—	2,128
Other non-current liabilities	346	25	15	—	386
Non-current liabilities — discontinued operations	—	—	5	—	5
Total non-current liabilities	8,113	704	8,314	(5,458)	11,673
Total liabilities	8,980	1,126	9,470	(6,108)	13,468
Minority interest	—	1	—	—	1
3.625% Preferred Stock	—	—	247	—	247
Stockholders' Equity	9,501	662	6,005	(10,163)	6,005
Total Liabilities and Stockholders' Equity	$ 18,481	$ 1,789	$ 15,722	$ (16,271)	$ 19,721

(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, 2006
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 869	$ 172	$ 651	$ (1,041)	$ 651
Adjustments to reconcile net income to net cash provided/(used) by operating activities					
Distributions in excess of (less than) equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(133)	(24)	(911)	1,041	(27)
Depreciation and amortization of nuclear fuel	453	30	7	—	490
Amortization of financing costs and debt discounts	—	5	19	—	24
Amortization of intangibles and out-of-market contracts	(390)	(3)	—	—	(393)
Amortization of unearned equity compensation	—	—	13	—	13
Write-off of deferred financing costs and debt premium	—	—	47	—	47
Write down and (gains)/losses of equity method investments	5	(13)	—	—	(8)
Changes in deferred income taxes	430	25	(146)	—	309
Nuclear decommissioning trust liability	9	—	—	—	9
Loss on sale of equipment	3	—	—	—	3
Changes in derivatives	(308)	1	6	—	(301)
Gain on legal settlement	—	(67)	—	—	(67)
Gain on sale of discontinued operations	—	(71)	—	—	(71)
Gain on sale of emission allowances	(68)	—	—	—	(68)
Changes in collateral deposit payments supporting of energy risk management activities	349	—	—	—	349
Cash provided/(used) by changes in working capital, net of acquisition and disposition affects	(494)	129	453	—	88
Net Cash Provided by Operating Activities	725	184	139	—	1,048
Cash Flows from Investing Activities					
Acquisition of Texas Genco LLC, WCP and Padoma, net of cash acquired	—	—	(4,336)	—	(4,336)
Capital expenditures	(140)	(17)	(2)	—	(159)
Decrease/(Increase) in restricted cash, net	2	(26)	—	—	(24)
Decrease/(Increase) in notes receivable	(922)	22	(3,063)	3,985	22
Purchases of emission allowances	(76)	—	—	—	(76)
Proceeds from sale of emission allowances	97	—	—	—	97
Investments in nuclear decommissioning trust fund securities	(158)	—	—	—	(158)
Proceeds from sales of nuclear decommissioning trust fund securities	149	—	—	—	149
Proceeds from sale of equipment	1	—	—	—	1
Proceeds from sale of investments	53	33	—	—	86
Proceeds from sale of discontinued operations	—	239	—	—	239
Net Cash Provided/(Used) by Investing Activities	(994)	251	(7,401)	3,985	(4,159)
Cash Flows from Financing Activities					
Payment of dividends to preferred stockholders	—	—	(37)	—	(37)
Payment for treasury stock	—	(297)	—	—	(297)
Funded letter of credit	—	—	350	—	350
Proceeds from Intercompany loans	3,063	—	922	(3,985)	—
Proceeds from issuance of common stock, net	—	—	986	—	986
Proceeds from issuance of preferred shares, net	—	—	486	—	486
Proceeds from issuance of long-term debt	—	198	7,175	—	7,373
Payment of deferred debt issuance costs	—	—	(174)	—	(174)
Payments of short and long-term debt	(2,751)	(42)	(1,904)	—	(4,697)
Net Cash Provided/(Used) by Financing Activities	312	(141)	7,804	(3,985)	3,990
Change in Cash from Discontinued Operations	—	14	—	—	14
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	2	—	—	2
Net Increase in Cash and Cash Equivalents	43	310	542	—	895
Cash and Cash Equivalents at Beginning of Period	(7)	78	422	—	493
Cash and Cash Equivalents at End of Period	$ 36	$ 388	$ 964	$ —	$ 1,388

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

NRG Energy, Inc. and Subsidiaries
Condensed Consolidating Statements of Operations
For the Three Months Ended September 30, 2005
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
Operating Revenues					
Revenues from majority-owned operations	$ 594	$ 93	$ 1	$ (1)	$ 687
Operating Costs and Expenses					
Cost of majority-owned operations	541	64	—	(1)	604
Depreciation and amortization	33	6	2	—	41
General, administrative and development	7	7	28	—	42
Impairment charges	6	—	—	—	6
Corporate relocation charges	—	—	2	—	2
Total operating costs and expenses	587	77	32	(1)	695
Operating Income/(Loss)	7	16	(31)	—	(8)
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	20	—	42	(62)	—
Equity in earnings of unconsolidated affiliates	14	15	—	—	29
Write downs and gains/(losses) on sales of equity method investments	—	4	—	—	4
Other income, net	2	12	1	(5)	10
Refinancing expense	—	—	(19)	—	(19)
Interest expense	—	(15)	(33)	5	(43)
Total other income/(expense)	36	16	(9)	(62)	(19)
Income/(Loss) From Continuing Operations Before Income Taxes	43	32	(40)	(62)	(27)
Income tax expense/(benefit)	11	12	(13)	—	10
Income/(Loss) From Continuing Operations	32	20	(27)	(62)	(37)
Income/(losses) from discontinued operations, net of income taxes	11	(1)	—	—	10
Net Income/(Loss)	$ 43	$ 19	$ (27)	$ (62)	$ (27)

(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, 2005
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
Operating Revenues					
Revenues from majority-owned operations	$ 1,475	$ 253	$ (1)	$ (4)	$ 1,723
Operating Costs and Expenses					
Cost of majority-owned operations	1,204	178	—	(4)	1,378
Depreciation and amortization	99	18	4	—	121
General, administrative and development	31	15	90	—	136
Impairment charges	6	—	—	—	6
Corporate relocation charges	—	—	6	—	6
Total operating costs and expenses	1,340	211	100	(4)	1,647
Operating Income/(Loss)	135	42	(101)	—	76
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	88	—	195	(283)	—
Equity in earnings of unconsolidated affiliates	30	52	—	—	82
Write downs and gains/(losses) on sales of equity method investments	—	16	—	—	16
Other income, net	4	46	6	(15)	41
Refinancing expense	—	—	(54)	—	(54)
Interest expense	—	(47)	(109)	15	(141)
Total other income (expense)	122	67	38	(283)	(56)
Income/(Loss) From Continuing Operations Before Income Taxes	257	109	(63)	(283)	20
Income tax expense/(benefit)	80	20	(76)	—	24
Income/(Loss) From Continuing Operations	177	89	13	(283)	(4)
Income from discontinued operations, net of income tax expense	11	6	7	—	24
Net Income	$ 188	$ 95	$ 20	$ (283)	$ 20

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

NRG Energy, Inc. and Subsidiaries
Condensed Consolidating Balance Sheet
December 31, 2005
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ (7)	$ 78	$ 422	$ —	$ 493
Restricted cash	3	46	—	—	49
Accounts receivable-trade, net	214	249	(214)	—	249
Inventory	232	8	—	—	240
Deferred income taxes	6	(1)	(5)	—	—
Derivative instruments valuation	385	(1)	3	—	387
Collateral on deposit in support of energy risk management activities	438	—	—	—	438
Prepayments and other current assets	63	42	550	(468)	187
Current assets held for sale	8	—	35	—	43
Current assets — discontinued operations	—	99	11	—	110
Total current assets	1,342	520	802	(468)	2,196
Net property, plant and equipment	2,176	412	21	—	2,609
Other Assets					
Investment in subsidiaries	787	—	1,774	(2,561)	—
Equity investments in affiliates	243	359	—	—	602
Notes receivable	76	457	1,397	(1,473)	457
Intangible assets, net	238	19	—	—	257
Derivative instruments valuation	18	—	—	—	18
Funded letter of credit	—	—	350	—	350
Deferred income taxes	—	26	—	—	26
Other non-current assets	22	19	83	—	124
Non—current assets — discontinued operations	—	814	13	—	827
Total other assets	1,384	1,694	3,617	(4,034)	2,661
Total Assets	$ 4,902	$ 2,626	$ 4,440	$ (4,502)	$ 7,466
LIABILITIES AND STOCK HOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 459	$ 90	$ 14	$ (468)	$ 95
Accounts payable	158	67	16	—	241
Derivative instruments valuation	678	1	—	—	679
Other bankruptcy settlement	—	3	—	—	3
Accrued expenses and other current liabilities	60	42	67	—	169
Current liabilities — discontinued operations	—	163	7	—	170
Total current liabilities	1,355	366	104	(468)	1,357
Other Liabilities					
Long-term debt and capital leases	1,397	620	1,866	(1,473)	2,410
Deferred income taxes	37	143	(52)	—	128
Derivative instruments valuation	25	11	20	—	56
Out-of-market contracts	298	—	—	—	298
Other non-current liabilities	126	22	22	—	170
Non-current liabilities — discontinued operations	—	568	1	—	569
Total non-current liabilities	1,883	1,364	1,857	(1,473)	3,631
Total liabilities	3,238	1,730	1,961	(1,941)	4,988
Minority interest	—	1	—	—	1
3.625% Preferred Stock	—	—	246	—	246
Stockholders' Equity	1,664	897	2,231	(2,561)	2,231
Total Liabilities and Stockholders' Equity	$ 4,902	$ 2,628	$ 4,438	$ (4,502)	$ 7,466

(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, 2005
(Unaudited)

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (a)	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 188	$ 95	$ 20	$ (283)	$ 20
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distributions in excess of/(less than) equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(54)	(33)	304	(216)	1
Depreciation and amortization	100	38	7	—	145
Amortization of financing costs and debt discounts	—	5	3	—	8
Amortization of intangibles and out-of-market contracts	11	5	—	—	16
Amortization of unearned equity compensation	2	—	6	—	8
Write-off of deferred financing costs and debt premium	—	(9)	2	—	(7)
Write downs and (gains)//losses on sale of equity method investments	—	(16)	—	—	(16)
Asset impairment	6	—	—	—	6
Changes in deferred income taxes	(172)	(4)	122	—	(54)
Minority interest	—	1	—	—	1
Changes in derivatives	245	3	4	—	252
Gain on legal settlement	—	(14)	—	—	(14)
Gain on sale of discontinued operations	—	(11)	—	—	(11)
Changes in collateral deposit payments supporting energy risk management activities	(598)	—	—	—	(598)
Cash provided/(used) by changes in working capital, net of acquisition and disposition affects	315	(402)	216	—	129
Net Cash Provided/(Used) by Operating Activities	43	(342)	684	(499)	(114)
Cash Flows from Investing Activities					
Capital expenditures	(32)	(11)	(3)	—	(46)
Decrease/(increase) in restricted cash, net	1	17	—	—	18
Decrease/(increase) in notes receivable	305	225	(430)	—	100
Proceeds from sale of investments	—	70	—	—	70
Proceeds on sale of discontinued operations	—	36	—	—	36
Return of capital from equity method investments and projects	—	1	—	—	1
Net Cash Provided/(Used) by Investing Activities	274	338	(433)	—	179
Cash Flows from Financing Activities					
Payments of dividends to preferred stockholders	(478)	(21)	(12)	499	(12)
Payment for treasury stock	—	—	(251)	—	(251)
Repayment of minority interest obligations	—	(4)	—	—	(4)
Borrowing under revolving line of credit	—	—	80	—	80
Proceeds from issuance of preferred stock, net	—	—	246	—	246
Proceeds from issuance of long-term debt, net	—	249	—	—	249
Deferred debt issuance costs	—	(2)	—	—	(2)
Payments for short and long-term debt	—	(331)	(648)	—	(979)
Net Cash Used by Financing Activities	(478)	(109)	(585)	499	(673)
Change in Cash from Discontinued Operations	—	17	—	—	17
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(1)	—	—	(1)
Change in Cash and Cash equivalents	(161)	(97)	(334)	—	(592)
Cash and Cash Equivalents at Beginning of Period	156	201	712	—	1,069
Cash and Cash Equivalents at End of Period	$ (5)	$ 104	$ 378	$ —	$ 477

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

Item 2 — Management's Discussion and Analysis of Financial Condition and Results of Operations

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

NRG Energy, Inc., "NRG", or the "Company", is a wholesale power generation company, primarily engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and overseas. NRG has a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. NRG's principal domestic generation assets consist of a diversified mix of natural gas, coal, oil and nuclear facilities, representing approximately 46%, 34%, 15% and 5% of the Company's total domestic generation capacity, respectively. In addition, approximately 15% of the Company's domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option. NRG has also acquired Padoma Wind Power LLC, making it likely that the Company will invest in domestic terrestrial wind projects.

NRG's 2005 Annual Report on Form 10-K includes a detailed discussion of various items impacting its business, results of operations, and financial condition. These include:

- *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 section.*

Critical accounting policies are the accounting policies that are most important to the portrayal of NRG's financial condition and results of operations and require management's most difficult, subjective, or complex judgment. NRG's critical accounting policies include revenue recognition and derivative accounting, income taxes and valuation allowance for deferred taxes, evaluation of assets for impairment and other than temporary decline in value, goodwill and other intangible assets, and contingencies.

This discussion and analysis explains the general financial condition and the results of operations for NRG, including:

- *factors which affect the business;*
- *earnings and costs in the periods presented;*
- *changes in earnings and costs between periods;*
- *sources of earnings;*
- *impact of these factors on NRG's overall financial condition;*
- *expected future expenditures for capital projects; and*
- *expected sources of cash for further operations and capital expenditures.*

As you read this discussion and analysis, refer to the consolidated statements of income which present the results of operations for the three and nine months ended September 30, 2006 and 2005. NRG analyzes and explains the differences between periods in the specific line items of the consolidated statements of income.

NRG has organized the discussion and analysis as follows:

- *changes to the business environment during the period;*
- *significant events that occurred in 2006 that are important to understanding the results of operations;*
- *results of operations beginning with an overview of NRG's consolidated results, followed by a more detailed discussion of those results by major operating segment;*
- *financial condition, addressing liquidity, the sources and uses of cash, capital resources and commitments;*
- *known trends that will affect its results of operation and financial condition in the future.*

Changes in Accounting Standards

See Note 1 to the condensed consolidated financial statements of this Form 10-Q as found in Item 1 for a discussion of recent accounting developments.

Regulatory Matter Developments

Northeast Region

Improvements in the New England market design should favorably impact revenues from operations in the fourth quarter 2006 and beyond. Interim capacity transition payments provided for under the FCM settlement are scheduled to commence December 1, 2006. In addition, the LFRM market for Connecticut cleared at the cap of $14 KW-month for the eight month winter period from October 1, 2006 to May 31, 2007. NRG sold 292 MW in LFRM auction and expects its participation in this market to increase revenues from the region. On November 3, 2006, the New England Power Pool participants committee voted to eliminate Peaking Unit Safe Harbor, or PUSH, bidding and the ISO-NE is expected to make a filing implementing this vote. The elimination of PUSH bidding would primarily impact NRG's Norwalk Harbor plant.

On September 29, 2006, the Management Committee of the NYISO approved a proposal sponsored by Consolidated Edison, or ConEd, to impose additional mitigation on the current owners of its divested generation units in New York City, including NRG with its Arthur Kill and Astoria facilities. The proposed mitigation effectively lowers the bid caps currently set forth in the NYISO tariffs that were specified at the time ConEd divested the units. NRG is contesting the proposal before the NYISO Board of Directors.

NRG expects that the Settlement Agreement filed on September 29, 2006, in the Reliability Pricing Model, or RPM, proceeding will have a positive impact on its operations in the region when it is implemented. The Settlement Agreement proposes to implement RPM, a locational forward capacity market. The Settlement Agreement, which is supported by the majority of the parties in the proceeding, makes a number of changes to the RPM proposal filed by PJM on August 31, 2005, including changes to the demand curve, use of 3-year forward auctions, inclusion of a Fixed Resource Requirement Alternative that allows certain load-serving entities to opt out, and a generator peak-period availability metric. The Settlement Agreement proposes to implement RPM with the annual planning period that begins June 1, 2007, and to commence the RPM forward auctions in April 2007.

West Region

On September 29, 2006, CAISO notified NRG that it wishes to extend the existing RMR agreements for NRG's Cabrillo Power I, LLC and Cabrillo Power II, LLC facilities currently scheduled to expire on December 31, 2006, for another year.

On September 21, 2006, FERC conditionally accepted the CAISO's Market Redesign and Technology Upgrade, or MRTU, proposal which is currently scheduled to go into effect in November 2007. Significant components of the MRTU include locational marginal pricing of energy, a more effective congestion management system, a day-ahead market, and an increase to the existing bid caps. NRG considers these market reforms to be a positive development.

On July 20, 2006, the California Public Utility Commission, or CPUC, issued an order toward establishing a standard Resource Adequacy Capacity Product that follows on its decision to impose local capacity requirements, which takes effect January 1, 2007. On the same date, the CPUC issued its order on long-term resource procurement that requires Southern California Edison, or SCE, to procure at least 1,500 MW over the next couple of years. NRG views these initiatives as positive developments and expects to participate in auctions and Request for Proposals, or RFP's, to supply power to SCE and other load-serving entities affected by the order.

For a further discussion on NRG's regulatory matters, see Note 16 to the Condensed Consolidated Financial Statements of this Form 10-Q. Some of this information is about costs that may be material to NRG's financial results.

Environmental Matter Developments

West Region

On September 27, 2006, Governor Arnold Schwarzenegger signed Assembly Bill 32 – California Global Warming Solutions Act of 2006 and Senate Bill 1368 – Electricity: Emissions of Greenhouse Gases. Assembly Bill 32, or AB 32, requires the state to develop a greenhouse gas, or GHG, reduction program to reduce emissions to 1990 levels by 2020, a reduction of approximately 25%. The reductions will be phased in beginning 2012 pursuant to regulations to be adopted by 2011. The financial impact to NRG will depend on final regulations. Senate Bill 1368, or SB 1368, prohibits utilities from entering into contracts of five years or more for any baseload generation exceeding a 60% capacity factor unless the contracting facility complies with a greenhouse gas performance standard no higher than the rate of GHG emissions for a combined cycle natural gas baseload power plant. NRG's California plants and development projects are unaffected by SB 1368 because they either meet the combined cycle standard or they do not exceed the 60% capacity factor and/or five year contract term thresholds.

Northeast Region

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap-and-trade greenhouse gas program for electric generators, referred to as the Regional Greenhouse Gas Initiative, or

RGGI. The state of Maryland has since announced its intent to join pending an analysis of its impact to the state. In August 2006, the states participating in RGGI released a model rule to be adopted by the states. The program begins in 2009. The model rule addresses program descriptions including, timelines, monitoring, the use of offsets, and allowance trading. Individual states including Connecticut, Delaware and New York in which NRG operates, must promulgate state rules which can be based on the model rule, and in addition, address allowance allocations, treatment of unallocated allowances and leakage. NRG continues to actively participate in state and regional RGGI proceedings.

The USEPA issued rules adding Delaware and New Jersey to the Clean Air Interstate Rule, or CAIR, because emissions from these states contribute to non-attainment of the fine particle pollution National Ambient Air Quality Standards in other states. The USEPA also reconfirmed its position on five contested CAIR issues including striking down the pollution control project, or PCP, exclusion under the NSR regulations.

A number of states in which NRG operates or intends to operate coal plants, including Connecticut, Delaware, Massachusetts and New York, plan to constrain in-state mercury emissions above and beyond the federal Clean Air Mercury Rule, or CAMR. These states are in various stages of finalizing state regulations and a state implementation plan which will cap the state's mercury emissions at the proposed CAMR cap and trade levels. Louisiana and Texas will adopt the EPA cap and trade program. NRG continues to actively track developments to determine its financial impact, if any, on its operations.

In the fourth quarter 2006, the DNREC is expected to promulgate Regulation No. 1146, or Reg 1146, Electric Generating Unit Multi-Pollutant Regulation and Section 111(d) of the State Plan for the Control of Mercury Emissions from Coal-Fired Electric Steam Generating Units. These regulations are expected to govern the control of SO_2, NOx and mercury emissions from electric generating units. NRG's current plans to install controls at its Indian River facility may be affected by the regulation when it is promulgated.

All Other Regions

In February 2006, the USEPA promulgated a regulation that sets New Source Performance Standards, or NSPS, criteria for air pollutants from utility, industrial, commercial, and institutional steam generating units. While the emissions control requirements already in place through USEPA's air permitting and air toxic programs require controls for boilers equivalent to those established by this rule, the final rule substantially tightens the existing NSPS. Units constructed or undergoing major modification after February 28, 2005 are affected.

For a further discussion on NRG's environmental matters see Note 17 to the Condensed Consolidated Financial Statements of this Form 10-Q. Some of this information includes costs that may be material to NRG's financial results.

Consolidated Results of Operations

The following table provides selected financial information for NRG Energy, Inc., for the three and nine months ended September 30, 2006 and 2005:

(In millions except otherwise noted)	Three months ended September 30, 2006	2005	Change %	Nine months ended September 30, 2006	2005	Change %
Operating Revenues						
Energy revenue	$ 1,070	$ 699	53%	$ 2,364	$ 1,385	71%
Capacity revenue	430	141	205	1,125	416	170
Alternative revenue	28	29	(3)	93	90	3
O & M fees	4	5	(20)	13	14	(7)
Risk management activities	156	(255)	NA	265	(291)	NA
Revenue contract amortization	224	4	NA	494	5	NA
Other revenues	88	64	38	125	104	20
Total operating revenues	2,000	687	191	4,479	1,723	160
Operating Costs and Expenses						
Cost of majority-owned operations	1,055	604	75	2,478	1,378	80
Depreciation and amortization	148	41	261	443	121	266
General, administrative and development	79	42	88	220	136	62
Impairment charges	—	6	NA	—	6	NA
Corporate relocation charges	—	2	NA	—	6	NA
Total operating costs and expenses	1,282	695	84	3,141	1,647	91
Operating income	718	(8)	NA	1,338	76	NA
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	17	29	(41)	46	82	(44)
Write downs and gains/(losses) on sales of equity method investments	(3)	4	NA	8	16	(50)
Other income, net	30	10	200	118	41	188
Refinancing expenses	—	(19)	NA	(178)	(54)	(230)
Interest expense	(154)	(43)	(258)	(420)	(141)	(198)
Total other (expenses)	(110)	(19)	(479)	(426)	(56)	(661)
Income/(Loss) from Continuing Operations before income tax expense	608	(27)	NA	912	20	NA
Income tax expense	235	10	NA	324	24	NA
Income/(Loss) from Continuing Operations	373	(37)	NA	588	(4)	NA
Income from discontinued operations, net of income tax expense	49	10	390	63	24	163
Net Income/(Loss)	$ 422	$ (27)	NA	$ 651	$ 20	NA
Business Metrics						
Average natural gas price – Henry Hub (S/MMbtu)	6.12	9.92	(38)%	6.90	7.76	(11)%

NA- Not Applicable

Significant Events Reflected in NRG's Results of Operations during the nine months ended September 30, 2006

Operational

- Total generation increased by 141% primarily due to the addition of NRG Texas to the NRG total portfolio.
- Improved operating performance and new tolling agreements contributed to $81 million of higher operating income from the South Central region.
- A mild winter and weakened power prices lowered generation demand for the Northeast region's peaking and intermediate assets by 57%.
- NRG recorded a gain of $68 million from the sale of excess emission allowances.
- NRG recorded $178 million in refinancing costs and $420 million in interest expense primarily due to new debt facilities associated with the acquisition of NRG Texas.
- Record peak energy demand in each of the market's served by NRG's major business segments ranging with increases of 4% to 11% over previous records.
- Recognized $265 million in gains from risk management activities.

Acquisitions/Dispositions

- On February 2, 2006, NRG acquired Texas Genco LLC. Texas Genco LLC is now a wholly-owned subsidiary of NRG, and is managed and accounted for as a separate business segment referred to as NRG Texas.
- On August 30, 2006, NRG announced the completion of the sale of its 100% owned Flinders power station and related assets. NRG received approximately $242 million in cash and recognized an after-tax gain on the sale of approximately $61 million.
- On March 31, 2006, NRG acquired Dynegy's 50% ownership interest in WCP, and became the sole owner of WCP's 1,808 MW of generation in Southern California. The results of operations of WCP were consolidated as of April 1, 2006, prior to which, NRG's 50% ownership of WCP was recorded as an equity method investment.
- On January 31, 2006, NRG finalized a settlement agreement with an equipment manufacturer related to certain turbine purchase agreements. Upon finalization of the settlement, NRG recorded a total of $67 million of other income, of which $35 million was related to the discharge of accounts payable previously recorded and $32 million was related to the receiving and recording of the equipment at fair value.

For the benefit of the following discussions, the tables below represent the results of NRG excluding the impact of NRG Texas and WCP for the three and nine months ended September 30, 2006:

For the three months ended September 30,	**2006**				**2005**
(In millions)	**Consolidated**	**NRG Texas**	**WCP**	**Total excluding NRG Texas/WCP**	**Consolidated**
Energy revenue	$ 1,070	$ 578	$ 31	$ 461	$ 699
Capacity revenue	430	234	27	169	141
Alternative revenue	28	—	—	28	29
O & M fees	4	—	—	4	5
Risk management activities	156	114	(2)	44	(255)
Contract amortization	224	219	—	5	4
Other revenues	88	6	3	79	64
Total Operating revenues	2,000	1,151	59	790	687
Cost of majority-owned operations	1,055	506	43	506	604
Depreciation and amortization	148	104	—	44	41
General, administrative and development	79	29	6	44	42
Impairment charges	—	—	—	—	6
Corporate relocation charges	—	—	—	—	2
Total operating costs and expenses	1,282	639	49	594	695
Operating income/(loss)	$ 718	$ 512	$ 10	$ 196	$ (8)

For the nine months ended September 30,	**2006**				**2005**
(In millions)	**Consolidated**	**NRG Texas (a)**	**WCP (b)**	**Total excluding NRG Texas**	**Consolidated**
Energy revenue	$ 2,364	$ 1,219	$ 58	$ 1,087	$ 1,385
Capacity revenue	1,125	624	47	454	416
Alternative revenue	93	—	—	93	90
O & M fees	13	—	—	13	14
Risk management activities	265	165	(3)	103	(291)
Contract amortization	494	481	—	13	5
Other revenues	125	9	6	110	104
Total Operating revenues	4,479	2,498	108	1,873	1,723
Cost of majority-owned operations	2,478	1,251	80	1,147	1,378
Depreciation and amortization	443	309	1	133	121
General, administrative and development	220	80	12	128	136
Impairment charges	—	—	—	—	6
Corporate relocation charges	—	—	—	—	6
Total operating costs and expenses	3,141	1,640	93	1,408	1,647
Operating income	$ 1,338	$ 858	$ 15	$ 465	$ 76

(a) Financial information for the results of operations for NRG Texas is for the period of February 2, 2006 to September 30, 2006

(b) Financial information for the results of operations for WCP is for the period of April 1, 2006 to September 30, 2006

Management's discussion of the results of operations for the three months ended September 30, 2006 and 2005

Revenues from Majority-Owned Operations

Total operating revenues from majority-owned operations rose by $1,313 million or 191%, from the third quarter 2005 to approximately $2.0 billion. Energy revenues comprised $1.1 billion of the total, with 47% contracted compared to $700 million in the third quarter of 2005 of which 11% was contracted. The current quarter's results were favorably impacted by the acquisition of NRG Texas, which contributed $1.2 billion to operating revenues, and included $578 million of energy revenues and $219 million related to contract amortization from out-of-market power contracts. Additionally, the acquisition of Dynegy's 50% interest in WCP, contributed $59 million to total operating revenues. Excluding NRG Texas and WCP, total operating revenues for the current quarter increased by $103 million, as generation demand for the Northeast region's intermediate and peaking plants declined by 43% compared to the third quarter 2005, were more than offset by $300 million in gains from risk management activities. Energy revenues, excluding NRG Texas and WCP, declined by $239 million, of which $225 million was due to lower power prices and lower generation in the Northeast region. Third quarter power prices in the Northeast region's two key New York markets fell by 32% and 28%, primarily due to a 37% decline in natural gas prices. The South Central region's total operating revenues declined by $10 million during the quarter compared to the same period in 2005, primarily due to lower purchased energy costs due to the netting of energy purchased for resale against merchant sales this quarter. For the third quarter 2005, the South Central region purchased energy primarily to service its load obligations and not for resale.

Capacity revenues for the three months ended September 30, 2006 increased by $289 million or 205%, compared to the three months ended September 30, 2005. Of this increase, $234 million was related to NRG Texas primarily from auction sales. In addition, capacity revenues increased to $27 million in the West region primarily due to the acquisition of WCP. The remainder of the increase was related to the Northeast region's New York assets where capacity prices increased from the third quarter of 2005 as well as a higher contract rate related to the Connecticut RMR settlement agreement.

Risk management activities not qualifying for hedge accounting treatment resulted in a total derivative gain of $156 million for the three months ended September 30, 2006 compared to a $260 million loss in the comparable quarter last year. NRG's third quarter 2006 gain was comprised of $27 million in financial revenue losses and $183 million of mark-to-market gains. The $27 million loss of financial revenues represents the settled value for the quarter of financial instruments that no longer qualify for hedge accounting treatment. Of the $183 million of mark-to-market gains, $161 million represents the change in fair value of forward sales of electricity and fuel, and $38 million represents the reversal of mark-to-market losses which ultimately settled as financial revenues. Additionally, NRG recognized a $16 million loss associated with its trading activity. These activities primarily support the Northeast and Texas regions' assets.

The following table shows NRG's risk management activities that do not qualify for hedge accounting treatment for the three months ended September 30, 2006 and 2005.

	Three months ended September 30, 2006					Three months ended September 30, 2005			
(In millions)	**Texas**	**Northeast**	**South Central**	**All Other**	**Total**	**Northeast**	**South Central**	**All Other**	**Total**
Net losses on settled positions, or financial revenues	$ (14)	$ (7)	$ (3)	$ (3)	$ (27)	$ (87)	$ (1)	$ —	$ (88)
Mark-to-market results									
Reversal of previously recognized unrealized losses on settled positions	—	38	—	—	38	1	—	—	1
Net unrealized gains/(losses) on open positions related to economic hedges	128	35	(2)	—	161	(172)	(1)	—	(173)
Net unrealized gains/(losses) on open positions related to trading activity	—	(33)	17	—	(16)	—	—	—	—
Subtotal mark-to-market results	128	40	15	—	183	(171)	(1)	—	(172)
Total derivative gain/(losses)(a)	$ 114	$ 33	$ 12	$ (3)	$ 156	$ (258)	$ (2)	$	$ (260)

(a) 2005 results includes derivative cost of energy

Since NRG risk management activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues (which are recorded net of financial instruments hedges that qualify for hedge accounting treatment) and costs of energy. In late 2005 and in 2006, NRG hedged a portion of its 2006 and 2007 Northeast region's generation. Since that time, the settled and forward prices of electricity have decreased, resulting in the recognition of mark-to-market forward sales and the settlement of such positions at reduced losses. Additionally, due to a decline in correlation between gas and power prices, $78 million of hedge accounting ineffectiveness on Texas hedge contracts was recognized. In 2005, Hurricanes Katrina and Rita disrupted gas production in the Gulf of Mexico causing a strong increase in natural gas prices resulting in a mark-to-market loss of approximately $173 million. Since the fourth quarter 2005, gas inventories have risen to levels that are approximately 10% above the average of the last five years, easing gas supply concerns and reducing forward 2007 gas prices by approximately 20%.

Cost of Majority-Owned Operations

Cost of majority-owned operations includes cost of energy, operating and maintenance expenses, and non-income tax expenses. For the three months ended September 30, 2006, cost of majority-owned operations was $1.1 billion or 53% of total operating revenues compared to $604 million, or 88%, of total operating revenues for the comparable period in 2005, an increase of $451 million or 75%. This increase in absolute terms but decrease in relative percentage terms was primarily due to NRG Texas which incurred costs of $506 million. Cost of energy increased from $516 million for the three months ended September 30, 2005 to $858 million for the three months ended September 30, 2006. The increase was primarily due to NRG Texas which recorded $406 million in cost of energy. Additionally, WCP's cost of energy for the third quarter 2006 was $33 million. Excluding NRG Texas and WCP, cost of energy decreased by $97 million. This decrease was driven by $94 million in lower cost of energy in the Northeast region primarily due to lower oil and gas fuel costs related to lower generation from oil- and gas-fired assets of approximately 52% and 13% respectively. The South Central region's cost of energy was lower in the third quarter 2006 compared to the same period in 2005 by $43 million primarily due to a reduction in the amount and price per MWh of purchased power and fewer unplanned outages at the region's baseload coal plants in 2006.

Other operating costs during the third quarter 2006 were $196 million compared to $88 million for the third quarter 2005. This increase was primarily driven by other operating costs related to NRG Texas of $101 million and WCP of $10 million.

Depreciation and Amortization

NRG's depreciation and amortization expense for the three months ended September 30, 2006 and 2005 was $148 million and $41 million, respectively. The increase in depreciation and amortization from was primarily due to the acquisition of NRG Texas.

General, Administrative and Development

NRG's general, administrative and development, or G&A, costs for the three months ended September 30, 2006 were $79 million or 4% of total operating revenues compared to $42 million or 6% of total operating revenue for the three months ended September 30, 2005. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees. G&A costs at NRG Texas were $17 million excluding corporate allocations and were $5 million at WCP. Corporate G&A incurred, before overhead allocations to regional segments, during the third quarter 2006 was $32 million compared to $22 million for the third quarter 2005. This $10 million increase was due to $4 million of non-recurring costs associated with the NRG Texas integration efforts and higher labor and consulting expenses. Development costs incurred in 2006 in support of NRG's recently announced repowering programs amounted to approximately $9 million.

Equity in Earnings of Unconsolidated Affiliates

For the three months ended September 30, 2006, NRG recorded $17 million in equity earnings from the Company's investments in unconsolidated affiliates, a 41% decrease from the comparable period last year of $29 million. Of the $12 million decrease, $7 million was due to the acquisition of Dynegy's 50% interest in WCP. As part of that transaction, NRG also sold its 50% interest in the Rocky Road investment, which accounted for $6 million of the decline in total equity earnings.

Other Income, Net

For the three months ended September 30, 2006 and 2005, NRG recorded other income of $30 million and $10 million, respectively. Other income is primarily comprised of interest income, of which NRG recorded $22 million and $9 million for the third quarter 2006 and 2005, respectively. The increase in interest income this quarter compared to the third quarter 2005 was due to average quarterly cash balances that were almost twice as large as in 2005. NRG also recorded $7 million of other income in this year's third quarter from the favorable settlement with respect to post closing adjustments on the acquisition of NRG's western NY plants in 1998 and 1999.

Interest Expense

Interest expense for the three months ended September 30, 2006 was $154 million compared to $43 million, for the three months ended September 30, 2005. Interest expense increased due to the servicing of new debt issued to finance the acquisition of NRG Texas. For further discussion of the acquisition and financing thereof, see Notes 3 and 8 to the condensed consolidated financial statements of this Form 10-Q.

In the first quarter 2006, NRG entered into interest rate swaps with the objective of fixing the interest rate on a portion of NRG's new Senior Credit Facility. These swaps were designated as cash flow hedges under FAS 133, and the impact associated with ineffectiveness was immaterial to NRG financial results. For the three months ended September 30, 2006, NRG had deferred gains of $10 million in other comprehensive income. See Note 8 to the condensed consolidated financial statements of this Form 10-Q for a further discussion on these interest rate swaps.

Refinancing Expense

During the three months ended September 30, 2005, NRG recorded $19 million of refinancing expense related to the repurchase of $229 million of its Second Priority Notes.

Income Tax Expense

Income tax expense was $235 million and $10 million for the three months ended September 30, 2006 and 2005, respectively. The effective tax rate was 38.7% and (37.0)% for the three months ended September 30, 2006 and 2005, respectively. The effective income tax rate for the three months ended September 30, 2006 differs from the U.S. statutory rate of 35% due to a property basis difference relating to disbursements from the disputed claims reserve, subpart F income and dividends, and earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the creation of valuation allowances in accordance with SFAS 109. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Income from Discontinued Operations, Net of Income Tax Expense

NRG classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the three months ended September 30, 2006, NRG recorded income from discontinued operations of $49 million, net of income tax expense compared to $10 million for the prior comparable period. For the three months ended September 30, 2006, discontinued operations consisted of the results of the Company's 100% owned Flinders power station, Resource Recovery and Audrain. For the third quarter 2005, discontinued operations consisted of the results of NRG McClain LLC, Northbrook New York, LLC, Northbrook Energy, LLC, Flinders, Resource Recovery and Audrain. NRG closed the sale of Flinders during the third quarter 2006 and recognized an after-tax gain of approximately $61 million from the sale. Discontinued operations for the three months ended September 30, 2005 included an $11 million after-tax gain on the disposition of NRG's Northbrook New York and Northbrook Energy operations.

Management's discussion of the results of operations for the nine months ended September 30, 2006 and 2005

Total operating revenues from majority-owned operations was $4.5 billion for the nine months ended September 30, 2006, an increase of 160% compared to $1.7 billion for the nine months ended September 30, 2005. Total operating revenues for the nine months ended September 30, 2006 included $2.4 billion of energy revenues, a 71% increase over the comparable period in 2005. Of the $2.4 billion in energy revenues, 53% was contracted compared to 14% for the nine months ended September 30, 2005. This increase was primarily due to the acquisition of NRG Texas. NRG Texas recorded $2.5 billion of total operating revenues for the nine months ended September 30, 2006. Of this amount, $1.2 billion was energy revenues, of which 80% were contracted. Excluding the results of NRG Texas and WCP, total operating revenues for the nine months ended September 30, 2006 was $1.9 billion, of which $1.1 billion were energy revenues, a decrease of $298 million compared to the nine months ended September 30, 2005. The decline in energy revenues was primarily due to lower generation and lower power prices in the Northeast region. Total generation in the Northeast region declined by 21% from the comparable period in 2005 reducing energy revenues by $317 million primarily due to decreased generation demand for NRG's peaking oil-fired and intermediate gas-fired plants, as an unseasonably mild winter and declining natural gas prices weakened power prices and demand in the region. Average power prices in NRG's two key New York markets declined by 15% and 17% for the nine months ended September 30, 2006 compared to the same period in 2005. The decrease in the Northeast region was partially offset by a $17 million increase from the South Central region's energy revenues as generation from NRG's South Central plants increased by 12% over the comparable prior period.

Capacity revenues for the nine months ended September 30, 2006 were $1.1 billion compared to $416 million for the nine months ended September 30, 2005, an increase of $709 million or 170%. The increase was largely due to capacity revenues related to NRG Texas of $624 million and WCP of $47 million. Excluding NRG Texas and WCP, capacity revenues increased by $38 million. Capacity revenues from the Northeast region increased by approximately $35 million due to higher New York capacity prices and higher rates related to the Connecticut RMR settlement agreement, the South Central region also saw increases in capacity revenues of approximately $10 million due to higher contract rates.

Risk management activities resulted in a total derivative gain of $265 million for the nine months ended September 30, 2006. This was comprised of $35 million in financial revenue losses and $300 million of mark-to-market gains. The $35 million loss on financial revenues represents the settled value for the nine months ended September 30, 2006 of financial instruments that do not qualify for hedge accounting treatment. Of the $300 million of mark-to-market gains, $208 million represents the change in fair value of forward sales of electricity and fuel, and $76 million represents the reversal of mark-to-market losses which ultimately settled as financial revenues. Additionally, NRG recognized a $16 million gain associated with trading activities. These trading activities primarily support the Northeast and South Central region's assets.

The following table shows NRG's risk management activities that do not qualify for hedge accounting treatment for the nine months ended September 30, 2006 and 2005.

	Nine months ended September 30, 2006					Nine months ended September 30, 2005			
(In millions)	Texas	Northeast	South Central	All Other	Total	Northeast	South Central	All Other	Total
Net gains/(losses) on settled positions, or financial revenues	$ (14)	$ (19)	$ 1	$ (3)	$ (35)	$ (39)	$ (1)	$ 1	$ (39)
Mark-to-market results									
Reversal of previously recognized unrealized (gains)/losses on settled positions	—	76	—	—	76	(51)	—	—	(51)
Net unrealized gains/(losses) on open positions related to economic hedges	179	32	(2)	(1)	208	(205)	(1)	—	(206)
Net unrealized gains/(losses) on open positions related to trading activity	—	(1)	17	—	16	—	—	—	—
Subtotal mark-to-market results	179	107	15	(1)	300	(256)	(1)	—	(257)
Total derivative gain/(losses) (a)	$ 165	$ 88	$ 16	$ (4)	$ 265	$ (295)	$ (2)	$ 1	$ (296)

(a) 2005 results includes derivative cost of energy

In late 2005 and in 2006, NRG hedged a portion of its 2006 and 2007 Northeast region's generation. Since that time, the settled and forward prices of electricity have decreased, resulting in the recognition of mark-to-market forward sales and the settlement of such positions at reduced losses. Additionally, due to a decline in correlation between gas and power prices, $122 million of hedge accounting ineffectiveness on Texas hedge contracts was recognized. In 2005, Hurricanes Katrina and Rita disrupted gas production in the Gulf of Mexico causing a strong increase in natural gas prices resulting in a mark-to-market loss of approximately $206 million. Since the fourth quarter 2005, gas inventories have risen to levels that are approximately 10% above the average of the last five years, easing gas supply concerns and reducing forward 2007 gas prices by approximately 20%.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the nine months ended September 30, 2006 was $2.5 billion or 56% of total operating revenues. Cost of majority-owned operations for the nine months ended September 30, 2005 was $1.4 billion or 80% of total operating revenues. The increase was primarily due to the acquisition of NRG Texas and WCP, of which NRG Texas recorded cost of majority-owned operations of $1.3 billion and WCP recorded $80 million. Excluding NRG Texas and WCP, cost of majority-owned operations decreased by $231 million, driven primarily by a $227 million decline in cost of energy to $864 million for the nine months ended September 30, 2006. This was due to a 21% decrease in generation in the Northeast region which drove fuel oil and gas costs down by $126 million and $66 million, respectively. Partially offsetting this decrease was higher coal costs in the Northeast region of $16 million primarily due to an increase in the cost of coal.

Other operating costs increased by $302 million to $589 million, $285 million related to the acquisition of NRG Texas and $21 million related to WCP. Excluding the impact of NRG Texas and WCP, other operating costs were 2% lower than last year. Operating and Maintenance costs benefited in the second quarter 2006 from an accrual reversal of $18 million related to a favorable court decision in a station service dispute at NRG's Western New York plants. This accrual reversal was offset by $12 million of higher major maintenance in the Northeast region related to maintenance activities to improve plant reliability and additional outage work at NRG's Oswego plant.

Depreciation and Amortization

NRG's depreciation and amortization expense for the nine months ended September 30, 2006 and 2005 was $443 million and $121 million, respectively. NRG Texas depreciation and amortization made up $309 million of the $322 million year-over-year increase.

General, Administrative and Development

NRG's G&A costs for the nine months ended September 30, 2006 were $220 million compared to $136 million for the nine months ended September 30, 2005. Corporate costs represented $102 million or 2% of total operating revenues and $72 million or 4% of total operating revenues for the periods ended September 30, 2006 and 2005, respectively. G&A costs were adversely impacted by $6 million of costs associated with the unsolicited acquisition offer by Mirant Corporation and $11 million of NRG Texas integration costs, partially offset by lower insurance costs. NRG also incurred a total of $15 million in development expenses in 2006 to support its recently announced repowering initiatives. The balance of the total increase in G&A was due to the acquisition of NRG Texas, which recorded $44 million, and WCP, which recorded $10 million, in G&A costs, excluding development and integration costs, for the nine months ended September 30, 2006.

Equity in Earnings of Unconsolidated Affiliates

For the nine months ended September 30, 2006, equity earnings from NRG's investments in unconsolidated affiliates were $46 million compared to $82 million for the nine months ended September 30, 2005, a decline of 44%. The decline in earnings was largely due to a number of sales of investments NRG completed over the past year. NRG's earnings in WCP accounted for $15 million of the decline as the results of WCP were fully consolidated as of March 31, 2006, the date of the purchase of Dynegy's 50% interest. As part of that transaction, NRG sold its 50% interest in the Rocky Road investment, which accounted for $7 million of the decline in total equity earnings. Additionally, NRG's Enfield investment, which was sold on April 1, 2005, earned $16 million for the nine months ended September 30, 2005. Sales of other equity investments in 2006 included James River, Cadillac and certain Latin American power funds. Declines in equity earnings as a result of these sales were offset by an approximately $7 million improvement in equity income from NRG's MIBRAG investment. MIBRAG experienced improved results compared to 2005 as a result of fewer customer outages and higher prices.

Gains on Sales of Equity Method Investments

During the nine months ended September 30, 2006, NRG sold its interests in James River, Cadillac, as well as interests in certain Latin American power funds for a pre-tax loss of $6 million, a pre-tax gain of $11 million and a pre-tax gain of $3 million, respectively. For the nine month ended September 30, 2005, NRG sold its 25% interest in its Enfield investment for a pre-tax gain of $12 million and its remaining interest in Kendall for a pre-tax gain of $4 million.

Other Income, Net

Other income increased by $77 million or 185% for the nine months ended September 30, 2006 to $118 million compared to the same period in 2005. Other income in 2006 was favorably impacted by $67 million of income associated with the settlement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001 and $7 million from the favorable settlement with respect to post closing adjustments on the acquisition of western NY plants in 1998 and 1999. In 2005, NRG recorded a $14 million gain from the settlement related to the Company's TermoRio project in Brazil and a contingent gain of $4 million related to the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. Other income was also favorably impacted by $11 million of higher interest income related to higher levels of cash and more efficient management of cash balances.

Refinancing Expense

Refinancing expenses for the nine months ended September 30, 2006 and 2005 were $178 million and $54 million, respectively. In the first quarter 2006, NRG acquired NRG Texas for a purchase price of approximately $6.2 billion. NRG partially financed this purchase through borrowings under new debt facilities and repaid and terminated previous debt facilities. As a result of this financing, NRG incurred $178 million of refinancing expenses for the nine months ended September 30, 2006. Of the $178 million, $127 million was related to the premium paid to NRG's previous debt holders, $34 million for the amortization of a bridge loan commitment entered into on September 30, 2005, and $31 million related to write-offs of deferred financing costs associated with NRG's previous debt, and a credit of $14 million related to a debt premium write-off.

In the first nine months of 2005, NRG redeemed and purchased a total of approximately $645 million of the Company's Second Priority Notes. As a result of the redemption and purchases, NRG incurred approximately $54 million in premiums and write-offs of deferred financing costs.

Interest Expense

Interest expense for the nine months ended September 30, 2006 was $420 million compared to $141 million for the nine months ended September 30, 2005. The increase in interest expense was primarily due to interest on new debt issued to finance the acquisition of NRG Texas. See Notes 3 and 8 to the condensed consolidated financial statements of this Form 10-Q for a further discussion of the acquisition and the related financing. As part of the refinancing, NRG replaced its previous senior secured term loan with a new $3.575 billion senior secured term loan. Additionally, NRG retired $1.1 billion of its 8% Second Priority Notes and issued $3.6 billion in senior unsecured notes with a weighted average interest rate of 7.33%.

In the first quarter 2006, NRG entered into interest rate swaps with the objective of fixing the interest rate on a portion of NRG's new Senior Credit Facility. These swaps were designated as cash flow hedges under FAS 133, and any impact associated with ineffectiveness was immaterial to NRG financial results. For the nine months ended September 30, 2006, NRG had deferred gains of $10 million in other comprehensive income. See Note 8 to the condensed consolidated financial statements of this Form 10-Q for a further discussion on these interest rate swaps.

Additionally, NRG designated an existing fixed-to-floating interest rate swap, previously as a hedge of NRG's 8% Second Priority Notes, into a fair value hedge of the Senior Notes which NRG closed on February 2, 2006. For the nine months ended September 30, 2006, NRG recognized $3 million in ineffectiveness associated with this hedge transaction. NRG does not anticipate any ineffectiveness of this hedge transaction in the future.

Income Tax Expense

Income tax expense was $324 million and $24 million for the nine months ended September 30, 2006 and 2005, respectively. The overall effective tax rate was 35.5% and 120.0% for the nine months ended September 30, 2006 and 2005, respectively. The effective income tax rate for the nine months ended September 30, 2006 and 2005 differs from the U.S. statutory rate of 35% due to a property basis difference relating to disbursements from the disputed claims reserve, subpart F income and dividends, and earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate. NRG's 2005 domestic income tax expense partially offset the low foreign effective tax rate due to the subpart F inclusion and taxation for the Company's gain on the sale of Enfield, of approximately $12 million.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the creation of valuation allowances in accordance with SFAS 109. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Income from Discontinued Operations, Net of Income Tax Expense

NRG classified as discontinued operations the income from operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the nine months ended September 30, 2006 and 2005, NRG recorded income from discontinued operations, net of income tax expense of $63 million and $24 million, respectively. Discontinued operations for the nine months ended September 30, 2006 was comprised of the results of Flinders, Audrain and Resource Recovery. Discontinued operations for the nine months ended September 30, 2005, consisted of the results of the Flinders, Audrain, Resource Recovery, Northbrook New York LLC, Northbrook Energy LLC and NRG McClain LLC. NRG closed on the sale of Flinders during the third quarter 2006 and recognized an after-tax gain of approximately $61 million from the sale. Discontinued operations for the nine months ended September 30, 2005 included an $11 million gain on the disposition of NRG's Northbrook New York and Northbrook Energy operations.

Business Segment Results

NRG Energy, Inc.'s identified reportable segments are primarily based on geographic areas, both domestic and foreign. On February 2, 2006, NRG acquired Texas Genco LLC now referred to as NRG Texas creating a separate segment of operations – Wholesale Power Generation – Texas.

The following is a detailed discussion of the results of operations of NRG's major wholesale power generation business segments.

Texas Region

For a discussion of the business profile of the Texas region, see pages 19-23 of NRG Energy, Inc's. 2005 Annual Report on Form 10-K.

Selected income statement data (In millions except otherwise noted)	**Three months ended September 30, 2006**	**Period ended September 30,2006 (a)**
Operating Revenues		
Energy revenue	$ 578	$ 1,219
Capacity revenue	234	624
Risk Management Activities	114	165
Contract amortization	219	481
Other revenues	6	9
Total operating revenues	1,151	2,498
Operating Costs and Expenses		
Cost of energy	406	966
Depreciation and amortization	104	309
Other operating expenses	129	365
Operating income	$ 512	$ 858
MWh sold (in thousands)	14,568	34,622
Business Metrics		
Average on-peak market power prices ($/MWh)	61.73	71.06
Cooling Degree Days, or CDDs (b)	1,541	2,667
CDD's 30 year rolling average	1,599	2,456
Heating Degree Days, or HDDs (b)	10	1,003
HDD's 30 year rolling average	—	1,382

(a) For the period February 2, 2006 to September 30, 2006 only.

(b) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An 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.

Quarterly Results

Operating Income

For the three months ended September 30, 2006, operating income for the Texas region was $512 million. Total generation for the quarter was 14 million MWh, approximately two million more than generated in the second quarter 2006. The Texas region achieved total sales volumes for the third quarter 2006 of approximately 14.6 million MWh of which 66% were sold under long-term agreements. The difference between MWh sold and MWh generated represents MWh purchased from the marketplace. In July and August, 2006, ERCOT set new records for peak demand, 62,396 MW on July 17 and 63,056 MW on August 17. Because of strong operating performance of the regions generating facilities, NRG Texas was able to fully participate in meeting these record demands. For the three months ended September 30, 2006, the Texas region's generating capacity was 96.8 available, including baseload availability of 99.2%.

Total Operating Revenues

Total operating revenues from the Texas region for the three months ended September 30, 2006 were $1.2 billion. Operating revenues included $578 million in energy revenues of which 66% were contracted. Capacity revenues totaled $234 million of which $100 million was related to investments in the STP nuclear generation facility. Additionally, the region recorded $219 million of contract amortization related to out-of-market power contracts assumed upon the acquisition.

Risk Management Activity – The total derivative gain for the quarter was $114 million, reflecting $78 million of ineffectiveness related to cash flow hedge positions.

Cost of Energy

Cost of energy for the Texas region was $406 million for the three months ended September 30, 2006. Coal and lignite costs were $143 million for the quarter, gas fuel costs were $218 million and nuclear fuel-related expenses were $14 million. These costs directly relate to the generation from the Texas region's coal-fired, gas-fired and nuclear-fired units. Coal costs included $36 million of lignite coal used at the Limestone coal plant. Also included in cost of energy were an emissions allowance expense of $11 million and $23 million in cost contract amortization for the quarter.

Other Operating Expenses

Other operating expenses for the Texas region for the three months ended September 30, 2006 were $129 million or 11% of the region's total operating revenues. These costs include $86 million of operating and maintenance costs of which 54% represents normal and major maintenance and $15 million of property tax expense. In addition, the Texas region incurred $29 million of G&A expense, of which $11 million was related to corporate allocations.

Year-to-date Results

Operating Income

For the period ended September 30, 2006, which includes results since the acquisition date of February 2, 2006, operating income for the Texas region was $858 million. These results were largely driven by $624 million of capacity revenues, energy revenues of $1.2 billion, and power contract amortization of $481 million. The Texas region's total generation for the period was approximately 33.6 million MWh. Total sales volumes for the period totaled 34.6 million MWh, of which 73% were sold under long-term sales agreements. NRG Texas purchased approximately 1 million MWh from the marketplace. For the period ended September 30, 2006, the region's generating facilities was 91.8% available, including baseload availability of 92.0%.

Total Operating Revenues

Total operating revenues were approximately $2.5 billion for the period ended September 30, 2006. Operating revenues included $1.2 billion in energy revenues of which 80% were contracted. Capacity revenues were $624 million, of which $261 million was related to the STP nuclear generation facility. Additionally, the Texas region recorded $481 million of contract amortization related to out-of-market power contracts assumed upon acquisition.

Risk Management Activity – The total derivative gain for the period was $165 million, reflecting $122 million of ineffectiveness related to cash flow hedge positions.

Cost of Energy

Cost of energy for the Texas region was approximately $1.0 billion for the period. Coal and lignite costs were $341 million, gas costs were $446 million and nuclear fuel expense was $40 million. These costs represent direct fuel-related costs for the generation of power from the Texas region. Purchased energy was $49 million, averaging $59 per MWh, acquired to cover contracted obligations. Also included in cost of energy was an emissions allowance expense of $28 million and $62 million in coal contract amortization for the period ended September 30, 2006.

Other Operating Expenses

Other operating expenses for the period ended September 30, 2006 were $365 million or 14% of total operating revenues. This included $241 million of operating and maintenance costs, 53% of which was related to normal and major maintenance and $45 million of property tax expense. G&A expense was $81 million for the period, including $36 million of charges related to corporate allocations.

Northeast Region

For a discussion of the business profile of the Northeast region, see pages 23-25 of NRG Energy, Inc's. 2005 Annual Report on Form 10-K.

(In millions except otherwise noted)	Three months ended September 30, 2006	2005	Change %	Nine months ended September 30, 2006	2005	Change %
Operating Revenues						
Energy revenue	$ 342	$ 567	(40)%	$ 763	$ 1,080	(29)%
Capacity revenue	98	74	32	247	212	17
Risk management activities	33	(254)	NA	88	(292)	NA
Other revenues	28	52	(48)	98	87	13
Total operating revenues	501	439	14	1,196	1,087	10
Operating Costs and Expenses						
Cost of energy	233	327	(29)	482	670	(28)
Other operating expenses	88	89	(1)	273	284	(4)
Depreciation and amortization	22	19	16	66	56	18
Operating income	$ 158	$ 4	NA	$ 375	$ 77	387
MWh sold (in thousands)	4,097	5,291	(23)	10,178	12,640	(19)
Business Metrics						
Average on-peak market power prices ($/MWh)	78.90	111.81	(29)	73.20	85.83	(15)
Cooling Degree Days, or CDDs(a)	1,022	1,251	(18)	1,302	1,585	(18)
CDD's 30 year rolling average	1,129	958	18	1,338	987	36
Heating Degree Days, or HDDs(a)	295	109	171	7,208	8,159	(12)
HDD's 30 year rolling average	101	164	(38)	7,970	10,004	(20)

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An 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.

Quarterly Results

Operating Income

Operating income for the Northeast region for the three months ended September 30, 2006 increased by $154 million to $158 million driven largely by a $287 million improvement in risk management activities including $202 million in unrealized derivative gains. The third quarter 2005 results included a $167 million loss in unrealized derivative positions driven by the run up in gas and power prices following Hurricane Katrina. Record gas storage brought about by mild winter weather pushed gas prices down 37% in the third quarter 2006 versus the same period in 2005. Power prices followed a similar pattern with Western New York, New York City, New England and Eastern PJM prices down 32%, 28% 32% and 24% respectively in the third quarter 2006 compared to the same period in 2005. These lower prices helped give rise to the $33 million gain recorded in the quarter on risk management activities. The decline in energy prices also explains the 40% or $225 million decline in energy revenues.

The third quarter 2006 started off strong with heat waves in late July and early August driving new records for peak energy demands in all the region's key markets Weather induced demand however began to moderate in late August and throughout September 2006. Northeast region generation fell 1.2 million MWh or 23% in the third quarter 2006 compared to the same period in 2005. Almost 55% of the generation decline was from the region's oil-fired generating units with declines in coal-fired generation accounting for 30% of the overall decrease. While regional plant capacity factor of 24% was 6% less than third quarter 2005, the region's baseload coal plants' EFOR improved this quarter from 8.8% to 6.2% due to ongoing investment in plant reliability projects.

Increased capacity revenues of $24 million reflected the continuation of higher capacity prices in the New York and Connecticut markets compared to the third quarter 2005. Operating income for the third quarter 2006 benefited from lower cost of energy of approximately $94 million or 29% compared to the same period in 2005, primarily due to lower generation. Other operating expenses were in line with the third quarter 2005.

Total Operating Revenues

Total operating revenues from the Northeast region increased by 14% to $501 million for the three months ended September 30, 2006 compared to $439 million for the three months ended September 30, 2005. Revenues for the three months ended September 30, 2006 included $342 million in energy revenues compared to $567 million for the three months ended September 30, 2005. This unfavorable decrease was due to lower generation and lower energy prices. Capacity revenues for the three months ended September 30, 2006 increased 32% to $98 million compared to $74 million for the three months ended September 30, 2005. The increase was primarily due to a new RMR agreement at several of the region's Connecticut facilities at higher approved rates than those prevailing during the third quarter 2005. In addition, capacity prices for both In-City and the rest of the state of New York have cleared at higher rates than in the prior comparable period in 2005 contributing $16 million of the total $24 million increase in quarterly capacity revenues.

Risk Management Activities — For the three months ended September 30, 2006, the Northeast region recorded a $33 million gain compared to a $254 million loss in the same period in 2005. The $33 million gain includes a $40 million unrealized gain related to the changes in fair value of forward derivative positions not qualifying for hedge accounting treatment as compared to a $171 million loss in the same period in 2005. This $40 million gain includes a $38 million benefit from the roll-off in the quarter of forward positions existing at end of fiscal year 2005. Risk management activity results in the third quarter 2006 included $7 million in realized losses on settled power positions. This compares with an $87 million loss in the third quarter 2005.

Other revenues in the third quarter 2006 of $28 million were down $24 million from the same period in the prior year. Such revenues in 2005 included $40 million in emission credit sales revenues. Following active trading of emission allowances in the first and second quarter of 2006, no similar sales occurred in the third quarter 2006.

Cost of Energy

Cost of energy in the Northeast region was approximately $233 million compared to $327 million in 2005, a decrease of $94 million or 29%. Oil costs in the Company's Northeast region decreased by $54 million reflecting reduced generation from the oil-fired plants. Similarly, gas costs of $94 million decreased by $15 million over the third quarter 2005 primarily due to lower generation from the New York City plants. Coal costs in the Northeast region decreased by $7 million, also due to lower generation partially offset by higher coal prices.

Other Operating Expenses

Other operating expenses include O&M expenses, non-income based taxes, and general & administrative expenses, or G&A. Other operating expenses for the Northeast region were $88 million for the third quarter 2006 compared to $89 million in the third quarter 2005. For the third quarter 2006, G&A expenses were approximately $21 million compared to approximately $26 million in the comparable period 2005. This decrease was primarily due to a reduction in corporate allocations as a result of the inclusion of NRG Texas to the NRG portfolio of $4 million combined with a reduction in insurance costs of $2 million.

Year-to-date Results

Operating Income

For the nine months ended September 30, 2006, operating income for the Northeast region increased by 387% to $375 million compared to $77 million for the nine months ended September 30, 2005. This was primarily driven by net forward mark-to-market gains, higher capacity revenues, and the sale of SO_2 emission allowances. The Northeast region recorded a net $88 million gain associated with forward sales of electricity associated with its risk management activities compared to a $292 million loss for the same period in 2005. Increased capacity revenues reflected higher capacity prices for the New York and Connecticut RMR assets compared to the first nine months of 2005.

Generation in the nine months ended Septem ber 30, 2006 decreased by 2.5 million MWh or 19% versus the comparable period in 2005. Generation from the region's oil-based units accounted for 75% of the decrease with declines from the region's Oswego plant alone accounting for 36% of the overall decrease. Coal-based generation was in line with the third quarter 2005 while gas-fired generation was down by approximately 0.6 million MWh. Lower generation followed weaker energy prices where Western New York, New York City, New England and Eastern PJM prices were down 15%, 17% 12% and 11% respectively for the nine months ended September 30, 2006 compared to the same period in 2005.

Lower generation combined with lower market prices accounted for a 29% decline in energy revenue to $763 million for the nine months ended September 30, 2006 compared to the same period in 2005. Other revenues of $98 million for the nine months ended September 30, 2006 were positively impacted by the sale of emission allowances, which contributed approximately $64 million for the nine months ended September 30, 2006 compared to $42 million for the same period in 2005.

Total Operating Revenues

Total operating revenues for the Northeast region increased by 10% to approximately $1.2 billion for the nine months ended September 30, 2006 compared to $1.1 billion for the nine months ended September 30, 2005. Revenues for the nine months ended

September 30, 2006 included $763 million in energy revenues compared to $1.1 billion for the same period in 2005. Of this $317 million decrease, approximately $210 million and $74 million can be attributed to the region's New York and New England assets, respectively. Capacity revenues for the nine months ended September 30, 2006 increased by $35 million or 17% to $247 million compared to $212 million for the prior comparable period in 2005. This increase was primarily due to $14 million of additional capacity revenues recorded during the first nine months of 2006 due to higher approved rates from the Connecticut RMR agreements. In addition, the Northeast region recognized $21 million in higher capacity revenues from the New York plants as in-City prices have been clearing at higher rates than the prior comparable period.

Risk Management Activities — For the nine months ended September 30, 2006, gains of approximately $88 million were recognized compared to losses of approximately $292 million for the same period in 2005. The $88 million gain included $107 million unrealized gains related to changes in fair value of forward derivative positions not qualifying for hedge accounting treatment compared to a $256 million loss in the same period in 2005. This $107 million gain includes a $76 million net benefit from the roll-off in the nine month period ended September 30, 2006 of forward positions associated with risk management activities existing at the end of fiscal year 2005. The $88 million gain in risk management activities included a $19 million realized loss on settled power positions.

Other revenues increased by 13% to $98 million for the first nine months of 2006 compared to $87 million for the same period in 2005. During the first half of 2006, the Northeast region realized $64 million in emission allowance sales compared to $42 million in the first nine months of 2005.

Cost of Energy

Cost of energy in the Northeast region decreased by 28% to $482 million for the nine months ended September 30, 2006 compared to $670 million for the same period in 2005. This was primarily due to lower generation from the New York City and Connecticut plants, which reduced oil and gas costs by approximately $126 million and $66 million, respectively. These costs were partially offset by higher coal costs of approximately $16 million to $235 million, an increase of 8% over the comparable prior period in 2005 due to higher coal prices.

Other Operating Expenses

Other operating expenses for the Northeast region were $273 million for the nine months ended September 30, 2006 compared to $284 million for the nine months ended September 30, 2005. Maintenance expenditures were $16 million higher this period than the prior comparable period, which more than offset an $18 million accrual reversal related to a favorable court decision related to station service obligations at the Western New York plants. Corporate allocations were lower by $12 million over the prior comparable period due to the inclusion of NRG Texas to the NRG portfolio. Property taxes were $5 million higher than the prior comparable period due to the reduction of property tax credit from the State of New York which was offset by lower insurance expense of $6 million.

South Central Region

For a discussion of the business profile of the South Central region, see pages 25-27 of NRG Energy, Inc's. 2005 Annual Report on Form 10-K.

(In millions except otherwise noted)	Three months ended September 30, 2006	2005	Change %	Nine months ended September 30, 2006	2005	Change %
Operating Revenues						
Energy revenue	$ 86	$ 101	(15)	$ 247	$ 230	7
Capacity revenue	50	46	9	147	137	7
Risk Management Activities	12	—	NA	16	—	NA
Contract amortization	5	5	—	13	11	18
Other revenues	12	23	(48)	8	23	(65)
Total operating revenues	165	175	(6)	431	401	7
Operating Costs and Expenses						
Cost of energy	98	141	(30)	237	279	(15)
Other operating expenses	19	24	(21)	66	75	(12)
Depreciation and amortization	15	15	—	45	45	—
Operating income/(loss)	$ 33	$ (5)	NA	$ 83	$ 2	NA
MWh sold (in thousands)	3,526	2,734	29	9,319	7,398	26
Business Metrics						
Average on-peak market power prices ($/MWh)	61.56	86.58	(29)	57.52	64.30	(11)
Cooling Degree Days, or CDDs(a)	1,541	1,626	(5)	2,667	2,563	4
CDD's 30 year rolling average	1,599	1,503	6	2,456	1,939	27
Heating Degree Days, or HDDs(a)	10	2	400	1,003	1,178	(15)
HDD's 30 year rolling average	—	1	NA	1,382	1,902	(27)

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An 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.

Quarterly Results

Operating Income

Operating income for the South Central region was up $38 million for the third quarter 2006 compared to the same period in 2005. The region's results were helped by strong operating performance at the Big Cajun II coal plant and tolling agreements. The Big Cajun II plant achieved an EFOR rate of 2.2% for the quarter, compared to the plant's EFOR rate of 7.9% in the third quarter 2005. The region also benefited from improved results in its risk management activities.

Total Operating Revenues

Total operating revenues for the third quarter 2006 decreased by $10 million, or 6%, compared to the third quarter 2005 primarily due to lower energy revenues, which declined by approximately $15 million. Energy sold to the region's contract customers increased by 112,000 MWh which resulted in a $4 million increase in contract energy revenues. Merchant energy revenues dropped by $20 million due to falling power prices and the impact of the netting energy purchases and resales under EITF 02-3. Average on-peak energy prices in the SERC Entergy region declined by 29% from the third quarter 2005 primarily due to the impact of Hurricane Katrina and the warm summer of 2005. Capacity revenue increased by approximately $4 million due to higher billing peaks for the region's cooperative contract customers. The cooperatives set a new summer peak of 2,011 megawatts on August 15, 2006. The increase in the region's risk management activities was primarily due to mark-to-market gains related to a contract with a counterparty.

Cost of Energy

South Central's cost of energy decreased by $43 million for the three months ended September 30, 2006 compared to the same period in 2005. The decrease was due to declining purchased power prices, fewer unplanned outages at the region's base-load coal plants in 2006, and to the impact of netting energy purchases and resales per EITF 02-3. Also, the third quarter 2005 results included the impacts of Hurricane Katrina, which drove up natural gas costs. Coal cost increased by $11 million due to higher generation at the region's coal plants. Plant generation increased 10% over the third quarter 2005. The region's tolling agreements provided an additional 0.9 million MWh of energy to support the region's load contracts and merchant sales.

Other Operating Expenses

Other operating expenses decreased by approximately $5 million during the third quarter 2006 compared to the third quarter 2005. Normal maintenance decreased by $1 million compared to the third quarter 2005 due to lower expenditures for boiler tube maintenance and substation maintenance. Major maintenance was also down $1 million because of lower spending on various projects, including river cell repairs. Corporate allocations decreased by $2 million in the third quarter 2006 compared to the third quarter 2005 as a result of the inclusion of NRG Texas in the NRG portfolio.

Year-to-date Results

Operating Income

Operating income for the nine months ended September 30, 2006, was up $81 million from the same period in 2005. This reflected better availability of the region's baseload coal plants, increased use of tolling agreements, and gains from the region's risk management activities. The region's Big Cajun II coal plant's performance was significantly better through the first nine months of 2006 than in the same period in 2005 as a result of a reduced number of forced outage hours from 1,289 in 2005 to 355 in 2006.

Total Operating Revenues

The region's energy revenue increased by $17 million primarily due to higher MWh sales to contract customers. Sales to cooperative customers were up by approximately 418,000 MWh and sales to other contract customers increased by approximately 48,000 MWh. The increased sales were driven by warmer weather, especially in the first half of 2006. Cooling degree days through September 30, 2006 were up by 333 days, while heating degree days were down 90 days compared to the first nine months of 2005. Capacity revenue increased by approximately $10 million because billing peaks set by the cooperative customers in the summer of 2005 were incorporated into 2006 capacity rates.

Cost of Energy

Cost of energy for the nine months ended September 30, 2006 decreased by 15%, or $42 million compared to the same period in 2005. Coal costs increased by approximately $20 million, reflecting an 11% increase in plant generation. Natural gas and purchase power costs declined by approximately $63 million, primarily due to higher coal plant availability and increased utilization of the region's tolling agreements which reduced the need to purchase energy to support contract load requirements. Transmission costs were up by approximately $5 million as a result of higher contract customer peaks and higher Entergy transmission tariffs.

Other Operating Expenses

For the nine months ended September 30, 2006, other operating expenses decreased by approximately $9 million from the same period in 2005. Normal maintenance decreased by approximately $1 million as better plant availability translated into lower expenditures for tube leaks and other forced outage items. Major maintenance also dropped by approximately $1 million due to project scheduling associated with the region's long-term maintenance plan. Corporate allocations declined by approximately $6 million as a result of the inclusion of NRG Texas in the NRG portfolio. These decreases were partially offset by an increase of approximately $1 million in external consulting expense related to the region's development projects.

West Region

For a discussion of the business profile of the West region, see pages 27-31 of NRG Energy, Inc's. 2005 Annual Report on Form 10-K.

(In millions except otherwise noted)	Three months ended September 30, 2006	2005	Change %	Nine months ended September 30, 2006	2005	Change
Operating Revenues						
Energy revenue	$ 31	$ 1	NA	$ 58	$ 1	NA
Capacity revenue	27	—	NA	47	—	NA
Risk management activities	(2)	—	NA	(3)	—	NA
Other revenues	3	—	NA	6	—	NA
Total operating revenues	59	1	NA	108	1	NA
Operating Costs and Expenses						
Cost of energy	33	1	NA	59	1	NA
Other operating expenses	16	1	NA	33	4	NA
Depreciation and amortization	—	—	NA	1	—	NA
Operating income/(loss)	$ 10	$ (1)	NA	$ 15	$ (4)	NA
MWh sold (in thousands)	718	4	NA	1,966	6	NA
Business Metrics						
Average on-peak market power prices ($/MWh)	69.71	80.68	(14)	59.10	62.75	(8)
Cooling Degree Days, or CDDs(a)	640	568	13	880	719	22
CDD's 30 year rolling average	574	481	19	731	539	36
Heating Degree Days, or HDDs(a)	52	53	(2)	1,921	1,847	4
HDD's 30 year rolling average	68	122	(44)	2,041	2,584	(21)

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An 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.

Quarterly and Year-to-date Results

Operating Income

For the three and nine months ended September 30, 2006, operating income for the West region was approximately $10 million and $15 million respectively, compared to a loss of $1 million and $4 million for the three and nine months ended September 30, 2005. This gain in operating income was entirely due to NRG's acquisition of Dynegy's 50% interest of WCP. The California high-voltage power grid handled an all time record peak demand on July 24, 2006 at 50,270 MW, with the previous record peak demand of 45,431 MW set on July 20, 2005.

Total Operating Revenues

Total operating revenues from the West region was approximately $59 million, comprised of $31 million in energy revenues, and $27 million of capacity revenues for the three months ended September 30, 2006. Total operating revenues for the nine months ended September 30, 2006 was $108 million, comprised of $58 million in energy revenues and $47 million in capacity revenues. This compares to $1 million in energy revenues for the three and nine months ended September 30, 2005.

Cost of Energy

Cost of energy for the three and nine months ended September 30, 2006, was approximately $33 million and $59 million, respectively. For the three and nine months ended September 30, 2005, cost of energy for the West region was $1 million.

Other Operating Expenses

Operating expenses for the West region for the three and nine months ended September 30, 2006 was $16 million and $33 million, respectively. This compares to $1 million and $4 million for the three and nine months ended September 30, 2005.

Liquidity and Capital Resources

Significant Events during the nine months ended September 30, 2006

Acquisitions and Dispositions

- The acquisition of Texas Genco LLC of $6.2 billion.
- Net proceeds of approximately $239 million and a net after-tax gain of approximately $71 million recognized from the sale of Flinders and Audrain.
- Proceeds of approximately $86 million from the sale of non-core assets.
- The purchase of the remaining 50% interest in WCP and sale of NRG's 50% interest in Rocky Road for a net $160 million.

Financings

- The issuance of approximately $147 million of notes and $50 million of preferred interests by unrestricted subsidiaries to partially fund the purchase of $297 million of NRG's common stock pursuant to a Capital Allocation Program announced on August 1, 2006.
- The issuance of $5.6 billion in a new credit facility, including a $1 billion revolving credit facility and $1 billion synthetic letter of credit facility; $3.6 billion in unsecured high yield notes; $500 million of 5.75% Preferred Stock; and $1 billion of common stock.
- The termination of NRG term loan, funded letter of credit and revolving credit facilities issued on December 24, 2004.
- The repurchase of $1.1 billion in aggregate principal amount of NRG's 8% Second Priority Notes.
- The repurchase of $1.1 billion in aggregate principal amount of NRG Texas's and Texas Genco Financing Corp.'s 6.875% senior notes.
- The return of cash collateral payments of $349 million due to the downward shift in the underlying price curves and settlement of trades.

Liquidity Position

As of September 30, 2006, NRG Energy, Inc.'s liquidity was approximately $2.4 billion and included approximately $1.5 billion of unrestricted and restricted cash. NRG's liquidity also included $843 million of borrowing capacity under the Company's revolving line of credit, and $142 million of availability under the Company's letter of credit facility. As of December 31, 2005, NRG's liquidity was $730 million and included $542 million of unrestricted and restricted cash. The Company's year-end liquidity also included $150 million of available capacity under the Company's revolving line of credit and $38 million of availability under the Company's letter of credit facility.

Capital Allocation Strategy

NRG's capital allocation philosophy includes reinvestment in its core facilities, maintenance of prudent debt levels and interest coverage, the regular return of capital to shareholders and investment in repowering opportunities. Each of these components is described further as follows:

- Reinvestment in Existing Assets – Opportunities to invest in the existing business, including maintenance and environmental capital expenditures that improve operational performance, ensure compliance with environmental laws and regulations, or expand projects.
- Management of Debt Levels – The Company uses several metrics to measure the efficiency of its capital structure and debt balances. Generally, the Company's targeted net debt to total capital ratio range is 45% to 60%. The Company intends to in the normal course of business to continue to manage its debt levels towards the lower end of the range and may, from time to time, pay down its debt balances for a variety of reasons.
- Return of Capital to Shareholders – The Company's debt instruments include restrictions on the amount of capital that can be returned to shareholders. The Company has in the past returned capital to shareholders while maintaining compliance with existing debt agreements and indentures. The Company expects to regularly return capital either through dividends or share repurchases to shareholders.
- Repowering Opportunities – The Company intends to pursue repowering initiatives that enhance and diversify its portfolio and provide a targeted economic return to the Company.

Capital Allocation Program

During the third quarter 2006, NRG initiated a plan, known as the Capital Allocation Program, to repurchase approximately $750 million of its common stock. Phase I was a $500 million stock repurchase program, which was completed on October 13, 2006. Phase II, as originally announced, was to be an additional $250 million common stock buyback anticipated to commence during the first quarter 2007. NRG has upsized Phase II to $500 million and has accelerated the start to the fourth quarter 2006 and is expected to be completed by the end of the second quarter 2007.

To implement Phase I, the Company formed two wholly-owned unrestricted subsidiaries to repurchase shares of NRG's common stock in the public markets or in privately negotiated transactions. These subsidiaries were funded with a combination of approximately $166 million in cash from NRG, together with the proceeds from the issuance of approximately $250 million in notes and approximately $84 million in preferred stock to Credit Suisse, for a total amount of approximately $500 million. As of September 30, 2006, the total amount of notes and preferred interests issued and outstanding was approximately $147 million and $50 million, respectively. Both the notes and the preferred interests will mature in two tranches: $137.5 million in notes and $53 million in preferred interests will mature in October 2008, and $112.5 million in notes and $31 million in preferred interests will mature in October 2009.

As of September 30, 2006, NRG through its two wholly-owned unrestricted subsidiaries had purchased approximately 6.1 million of its common stock at an average price of $48.61 per share for a total amount of approximately $297 million. On October 13, NRG completed Phase I of the program with total common stock repurchased of 10,587,700 common shares at an average price of $47.22 for approximately $500 million.

Australia

On August 30, 2006, NRG announced the completion of the sale of its 100% owned Flinders power station and related assets or Flinders, located near Port Augusta, Australia, to Babcock & Brown Power Pty, a subsidiary of Babcock & Brown, a global investment and advisory firm. Proceeds from the sale were approximately $242 million (AU$317 million). The sale resulted in the elimination of approximately $370 million (AU$485 million) of consolidated liabilities including approximately $183 million (AU$240 million) of non-recourse debt obligations and approximately $92 million (AU$121 million) in non-current liabilities related to the obligations for the purchase of electricity and the supply of fuel to the Osborne power station that were guaranteed by NRG. NRG recognized an after-tax gain of approximately $61 million from the sale.

Acquisition of Texas Genco and Related Financing

On February 2, 2006, NRG acquired Texas Genco LLC, pursuant to an Acquisition Agreement dated September 30, 2005. The purchase price of approximately $6.2 billion consisted of approximately $4.4 billion in cash, the issuance of approximately 35.4 million shares of NRG's common stock valued at approximately $1.7 billion and acquisition costs of approximately $0.1 billion. This amount may be subject to an adjustment due to additional acquisition costs. The value of NRG's common stock issued to the Sellers was based on the Company's average stock price immediately before and after the closing date of February 2, 2006. The acquisition also included the assumption of approximately $2.7 billion of Texas Genco LLC debt. In connection with the acquisition, NRG substantially revised its financial structure.

The acquisition of Texas Genco LLC and the related financial restructuring was funded with (i) cash proceeds received upon the issuance and sale in a public offering of 20,855,057 shares of NRG common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $1.2 billion aggregate principal amount of 7.25% Senior Notes due 2014 and $2.4 billion aggregate principal amount of 7.375% Senior Notes due 2016; (iii) cash proceeds received upon the issuance and sale in a public offering of 2 million shares of mandatory convertible preferred stock at a price of $250 per share; (iv) funds borrowed under a new senior secured credit facility consisting of a $3.575 billion term loan facility, a $1.0 billion revolving credit facility and a $1.0 billion synthetic letter of credit facility; and (v) cash on hand.

On January 31, 2006, NRG used proceeds from the issuance of common stock and cash on hand to repay the $446 million outstanding principal balance of the Company's senior secured term loan facility, along with accrued but unpaid interest of approximately $2 million and terminated the facility. On February 2, 2006, NRG used proceeds from the new debt financing to pay accrued but unpaid fees on the Company's revolving credit facility and funded letter of credit facility, and terminated those facilities. Those facilities were replaced by the new term loan, letter of credit and revolving financing facilities as of February 2, 2006.

NRG's previously outstanding 8% Second Priority Notes of approximately $1.2 billion were repurchased by NRG on February 2, 2006 and previously outstanding Texas Genco Notes of approximately $1.2 billion were purchased by NRG on February 3, 2006, with proceeds from the issuance of new unsecured high yield notes.

As of September 30, 2006, NRG had $3.6 billion in aggregate principal amount of unsecured high yield notes or Senior Notes and approximately $3.6 billion in principal amount outstanding under the term loan and had issued $858 million of letters of credit under the Company's $1 billion funded letter of credit facility, leaving $142 million available for future issuances. Under the Company's $1 billion revolving facility, as of September 30, 2006, NRG had issued $157 million in letters of credit, leaving $843 million available for borrowings, of which approximately $143 million could be used to issue additional letters of credit. As of November 1, 2006, $160 million of undrawn letters of credit remain available under the funded letter of credit facility, $143 million of undrawn letters of credit remain available under the revolving credit facility, and NRG had no borrowings on the Company's revolving credit facility.

Collateral

In connection with the Company's power generation business, NRG manages the commodity price risk associated with the Company's supply activities and electric generation facilities. This includes forward power sales, fuel and energy purchases and emission allowances. In order to manage these risks, NRG enters into financial instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy. NRG utilizes a variety of instruments including forward contracts, futures contracts, swaps and options. Certain of these contract counterparties require NRG to post margin collateral. As of November 1, 2006, NRG had posted $113 million in collateral to support these contracts.

In March 2004, NRG entered into two interest rate swap agreements, one of which matured on March 31, 2006. The remaining swap agreement matures in 2011. Depending on market interest rates, NRG or the swap counterparty may be required to post collateral on a daily basis in support of this swap, to the benefit of the other party. On September 30, 2006 and November 1, 2006, NRG had posted approximately $12 million and $11 million, respectively, in collateral.

Second Lien Structure

NRG has granted second priority liens on substantially all of its assets in the United States in order to secure obligations under certain power sale agreements and related hedges. NRG uses the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under these agreements. As of October 31, 2006, the net discounted exposure on the agreements and hedges that were subject to the second lien structure was approximately $905 million.

The following table summarizes the utilization of the second lien structure as of October 31, 2006:

Equivalent Net Sales secured by Second Lien Structure (a)	2006 (b)	2007	2008	2009	2010	2011
In MW	2,062	3,402	3,421	3,766	2,875	3,353
As a percentage of net baseload capacity in collateral pool	30%	49%	49%	54%	41%	48%

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.

(b) 2006 MW value consists of November and December positions only.

NOL's and Deferred Tax Assets

As of September 30, 2006 NRG had U.S. domestic net operating loss carryforward of $271 million which will expire through 2026, including $15 million of NOL which is eligible for carryback to prior periods. NRG believes that it is more likely than not that a benefit will be realized on the deferred tax assets relating to the net operating loss carryforwards. This assessment included consideration of positive and negative factors, including NRG's current financial position, results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. As of September 30, 2006, no valuation allowance was recorded against deferred tax assets relating to net operating loss carryforwards with any pre-existing valuation allowance relating to any net operating loss carryforwards reversed.

Discussion of Known Trends

Repowering Initiative

On June 21, 2006, NRG announced a comprehensive portfolio redevelopment effort, which involves the development, financing, construction and operation of up to 10,000 megawatts of new multi-fuel, multi-technology generation capacity at NRG's existing domestic sites to meet the growing demand in all of the Company's core domestic markets. Through this repowering initiative, NRG's total generation could potentially increase from approximately 22,800 MW to 32,800 MW for a total cost of up to $16 billion. Both the increase in NRG's generation and NRG's share of the costs are dependent upon a number of factors, including successfully obtaining required permits and off-take agreements and achieving targeted project economics. In addition, NRG expects to mitigate the capital cost of its repowering initiative through sell-downs of equity and public-private partnerships. The Company also expects to charge development fees to equity partners. To mitigate the investment risks, NRG anticipates entering into long-term PPAs and EPC contracts. The Company currently expects its share of cash contributions for the repowering investments to be between $500 million and $1.5 billion.

The total 10,000 MW increase based on fuel type is as follows:

Fuel Type	Megawatts
Gas	2,800
Nuclear	2,700
Coal Gasification, or IGCC	2,250
Solid Fuel	1,800
Wind	450
Total	10,000

Capital Expenditures

Capital expenditures were approximately $159 million and $46 million for the nine months ended September 30, 2006 and 2005, respectively. Of these amounts, environmental capital expenditures for the nine months ended September 30, 2006 and 2005 were approximately $9 million and $16 million, respectively. Capital expenditures for the fourth quarter 2006 are expected to be approximately $56 million of which $4 million will be related to environmental capital expenditures.

NRG has estimated that approximately $1.3 billion of environmental capital expenditures will be incurred during the period 2007 through 2012, primarily related to installation of particulate, SO_2, NO_X, and mercury controls to comply with the CAIR and Clean Air Mercury rules, as well as installation of BTA under the Phase II 316(b) Rule. NRG currently updates its estimates for environmental capital expenditures annually, and these estimates can be expected to change over time, in some cases materially.

The following table summarizes the estimated environmental capital expenditures for the referenced period, by region and by year:

(In millions)	Texas	Northeast	South Central	Other	Total
Periods:					
2007	10	118	40	9	177
2008	13	174	92	10	289
2009	23	206	179	5	412
2010	26	138	86	4	255
2011	19	27	52	1	99
2012	13	5	34	—	52
Total	103	669	481	29	1,284

NRG is working to reduce or mitigate a portion of the above environmental capital expenditures. To date, two potential mitigants have been identified. First, NRG has the ability to monetize a portion of the Company's excess emission allowances over the 2007-2012 timeframe and still leave sufficient credits to operate the fleet at existing levels through 2020. Secondly, NRG's current contracts with its rural electrical customers in the South Central region allow recovery of up to approximately 93% of costs incurred by complying with new laws, including interest over the asset life of the required expenditure for the duration of the contracts. Actual recoveries may be less and will depend, among other things, on the duration of the contracts and the treatment of the expenditures.

Hedge Reset and Extension

On November 3, 2006, NRG announced its intention to enter into a series of transactions that includes (i) the reset of existing out-of-the-money hedges for years 2006 through 2010 to market, (ii) substantial new baseload hedges for the years 2010 and 2011 and, possibly, later years, (iii) the issuance of $1.1 billion of new high yield notes and (iv) amendments to NRG's existing Senior Credit Facility, including the increase of the synthetic letter of credit facility by $500 million.

Resetting of Existing Hedges, or Hedge Reset — NRG has entered into amendments of certain existing hedge agreements for the years 2006 through 2010, including hedge agreements with J. Aron & Company. These hedges were gas swaps and power contracts that were acquired as part of the acquisition of Texas Genco LLC, which closed on February 2, 2006. These hedges were entered into by Texas Genco at a time when power and natural gas prices were lower than they are today, and as a result, the hedges obligate NRG to sell power or natural gas at prices significantly below current market prices. Under the amended agreements, NRG has reset the pricing of these hedges to reflect current market prices, and has agreed to pay cash to the hedge counterparties in amounts that reflect a negotiated present value of the difference between the original prices in the hedges and the amended prices. The total amount to be paid to the counterparties is expected to be approximately $1.35 billion.

The Hedge Reset will provide the flexibility through NRG's second lien structure to expand its hedges on baseload generation for an extended period, and will improve the Company's cash flows and credit profile which will contribute to the Company's ability to amend its existing Senior Credit Facility, as described below.

The following table summarizes the Texas region's percentage of hedged baseload capacity and the corresponding revenues (excluding revenues from contract amortization) resulting from baseload hedge agreements that were contracted by Texas Genco LLC and assumed by NRG as of February 2, 2006 compared to the revenues (excluding revenues from contract amortization) expected from the hedges following the Hedge Reset:

(In million unless otherwise stated)	**December 2006**	**2007**	**2008**	**2009**	**2010**
Texas Region Net Baseload Capacity (MW)	5,294	5,340	5,340	5,340	5,340
Texas Region Baseload Sales (MW)[(a)]	4,575	4,267	4,157	3,449	1,395
Percentage Baseload Capacity Sold Forward[(b)]	86%	80%	78%	65%	26%
As of Acquisition:					
Weighted Average Forward Price ($/MWh)[(c)]	$ 43	$ 39	$ 41	$ 47	$ 51
Total Forward Hedged Revenues [(c)]	146	1,443	1,505	1,434	621
After Reset:					
Weighted Average Forward Price ($/MWh)[(c)]	51	56	54	57	55
Total Forward Hedged Revenues [(c)]	173	2,103	1,963	1,707	723
Increase in Forward Hedged Revenues due to Hedge Reset	$ 27	$ 660	$ 458	$ 273	$ 102

(a) Includes amounts under fixed price power sales contracts and financially hedged under natural gas swap contracts. The forward natural gas swap quantities are reflected in equivalent MWh and are derived by first dividing the quantity of MMBtu of natural gas hedged by the forward market heat rate as of December 30, 2005 to arrive at the equivalent MWh hedged which is then divided by 8,760 hours (total hours in a year) to arrive at MW hedged.

(b) Percentage hedged is based on total MWh sold as power and gas converted using the method as described in (a) above divided by the net capacity. The net capacity excludes loss in generation from expected forced outages and in generation from forecasted market uncertainties.

(c) Includes amounts under fixed price power sales contracts and financially hedged under natural gas swap contracts.

Based on the table above, due to the Hedge Reset of the Texas region's hedges that were outstanding as of February 2, 2006, revenues (exclusively revenues from contract amortization) during the period December 2006-2011 will increase by approximately $1.5 billion.

New Hedges — NRG has entered into, and will continue to enter into, new forward natural gas swaps contracts for the years 2010 and 2011, in order to hedge future power prices with respect to NRG's baseload power generation facilities in those years. As appropriate market opportunities arise, NRG will extend the hedging program to later years. As a result of these transactions, NRG will be significantly more hedged with respect to its baseload power generation through 2011. NRG's obligations under the New Hedges and Hedge Reset are or will be secured by second liens on substantially all of the assets of NRG and its subsidiaries, pursuant to NRG's existing second lien structure.

The following table summarizes NRG's total baseload capacity and the corresponding revenues (excluding revenues from contract amortization) resulting from baseload hedge agreements extending beyond December 2006 through 2011:

(In million unless otherwise stated)	December 2006	2007	2008	2009	2010	2011	Annual Average for 2007-2011
NRG Net Baseload Capacity (MW)	8,660	8,660	8,660	8,660	8,660	8,660	8,660
NRG Baseload Sales (MW)(a)	6,270	6,691	5,766	5,002	3,614	3,548	4,924
Percentage Baseload Capacity Sold Forward (b)	72%	77%	67%	58%	42%	41%	57%
Weighted Average Forward Price ($ per MWh)(c)	$ 49	$ 45	$ 53	$ 55	$ 55	$ 48	$ 51
Total Forward Hedged Revenues (c)	$ 227	$ 2,609	$ 2,672	$ 2,423	$ 1,736	$ 1,490	$ 2,186

(a) Includes amounts under fixed price power sales contracts and amounts financially hedged under natural gas swap contracts. The forward natural gas swap quantities are reflected in equivalent MWh and are derived by first dividing the quantity of MMBtu of natural gas hedged by the forward market heat rate as of October 31, 2006 to arrive at the equivalent MWh hedged which is then divided by 8,760 hours (total hours in a year) to arrive at MW hedged.

(b) Percentage hedged is based on total MWh sold as power and gas converted using the method as described in (a) above divided by the net capacity. The net capacity excludes loss in generation from expected forced outages and in generation from forecasted market uncertainties.

(c) Includes amounts under fixed price power sales contracts and financially hedged under natural gas swap contracts.

Issuance of New High Yield Notes — NRG plans to finance the payments required in order to reset the existing hedges with cash on hand and with proceeds from the issuance of $1.1 billion of new high yield notes.

Amendment of Senior Credit Facility — NRG plans to amend its existing Senior Credit Facility to accomplish, among other things, the following objectives:

- to permit the incurrence of the new debt represented by the new high yield notes;
- to increase the amount of the synthetic letter of credit facility by $500 million, from $1.0 billion to $1.5 billion;
- to increase the Available Amount, and effect a corresponding increase in NRG's restricted payments capacity, by $250 million; and
- to provide additional flexibility to NRG with respect to certain covenants governing or restricting the use of excess cash flow, new investments, new indebtedness and permitted liens.

The amendments to the existing hedges, the issuance of the new high yield notes, and the amendments to the Senior Credit Facility are expected to close by November 21, 2006. NRG has entered into bridge agreements with Merrill Lynch & Co. to assure that it has adequate financing to fund the amounts owed to the hedge counterparties, and Merrill Lynch & Co. has issued a commitment to NRG to refinance its Senior Credit Facility if the desired amendments to the existing facilities cannot be procured.

Impact to Results of Operations — NRG will account for the Hedge Reset as a net settlement of its current hedge positions and a subsequent reestablishment of new hedge positions. The impact of the net settlement will be recorded as a decrease to NRG's consolidated revenues with an offsetting increase in revenues from a reduction in the associated derivative liability and the associated out-of-market power contract balance established upon the Acquisition of NRG Texas.

As of October 31, 2006, NRG expects the impact to comprise of the following:

(In millions)	
Settlement payment	$ (1,347)
Reduction in derivative liability	146
Reduction in out-of-market contracts	1,073
Net decrease in revenues	(128)
Impact on 2006 earnings, net of tax	(76)

Cash Flow Discussion

(In millions)	Nine months ended September 30, 2006	2005
Net cash provided/(used) by operating activities	$ 1,048	$ (114)
Net cash provided/(used) in investing activities	(4,159)	179
Net cash provided/(used) by financing activities	$ 3,990	$ (673)

Net Cash Provided/(Used) By Operating Activities

For the nine months ended September 30, 2006, net cash provided by operating activities increased by $1,162 million compared to the same period in 2005. This was primarily due to the following reasons:

- Due to expiration of the underlying contracts and the downward shift of the forward price curves, NRG's cash collateral deposits in support of derivative contracts decreased by $349 million during the nine months ended September 30, 2006, compared to an increase of $598 million during the same period in 2005, a difference of $947 million. As of September 30, 2006 NRG had cash collateral deposits of $132 million;
- Due to the redemption of NRG's previous senior notes, a premium of $126 million was paid to NRG's former debt holders;
- NRG's activity for the period resulted in an increase of $88 million in working capital compared to an increase in working capital for the same period in 2005 of $129 million, a difference of $41 million;
- Due to redemption of NRG's 8% Second Priority Notes, during the nine months ended September 30, 2006, NRG wrote off $61 million of deferred financing costs less debt premium of $14 million for a net write-off of $47 million, compared to a write-off of debt premiums of $7 million during the same period in 2005, a difference of $54 million; and
- A gain on the sale of emission allowances adjusted net income by $68 million to reflect the activity as investing. Due to price conditions, it was economically beneficial to sell emissions rather than operate certain plants.

Net Cash Provided/(Used) By Investing Activities

For the nine months ended September 30, 2006, net cash used in investing activities was approximately $4.2 billion more than the same period in 2005. NRG's use of cash was due to the following mix of investment activities:

- During the first quarter 2006, NRG acquired Texas Genco LLC for approximately $6.2 billion (net of assumed debt), which included the issuance of stock at a value of $1.7 billion and a net cash payment of approximately $4.3 billion (net of cash on hand at NRG Texas of $238 million);
- NRG acquired Dynegy's 50% ownership interest in WCP for $25 million (net of cash on hand at WCP of $180 million). Prior to the purchase, NRG had an existing investment in WCP accounted for as an unconsolidated equity method investment;
- During the third quarter 2006, NRG completed the acquisition of Padoma for net cash of $7 million.
- As disclosed in Note 5 to the condensed consolidated financial statements of this Form 10-Q, NRG divested a number of its equity investments for total proceeds of $86 million, in addition, NRG received approximately $239 million in net proceeds from sale of discontinued operations.
- NRG's capital expenditures was $113 million more during the nine months ended September 30, 2006 than the same period in 2005, with the increase primarily related to capital expenditures at NRG Texas; and
- During the nine months ended September 30, 2005, NRG received $70 million related to the TermoRio settlement.

Net Cash Provided/(Used) in Financing Activities

For the nine months ended September 30, 2006, net cash provided by financing activities increased by approximately $4.7 billion in comparison to the same period in 2005. The increase was primarily due to the financing activities related to the purchase of NRG Texas:

- In connection with the Capital Allocation Program, during the third quarter 2006, NRG through its two wholly-owned unrestricted subsidiaries issued approximately $147 million in notes and $50 million in preferred interests to partially fund the purchase of $297 million of NRG's common stock.
- In conjunction with the purchase of NRG Texas, NRG refinanced its outstanding debt as well as NRG Texas's outstanding debt as the Company:
  - Repaid $446 million in outstanding principal and terminated its term loan under NRG's Amended Credit Facility;
  - Repurchased and retired approximately $1.1 billion of NRG's 8% Second Priority Notes, pursuant to a tender offer; and
  - Repurchased NRG Texas's outstanding notes for approximately $1.1 billion and NRG Texas's term loan for approximately $500 million.

- As part of raising the funds to purchase NRG Texas and to refinance the combined NRG debt portfolio, the company:
  - Issued 20,855,057 shares of common stock on January 31, 2006 at an offering price of $48.75 per share for total net proceeds of approximately $986 million, after deducting expenses;
  - Issued 2 million shares of 5.75% Preferred Stock on January 30, 2006 at an offering price of $250 per share for total net proceeds of approximately $486 million, after deducting expenses;
  - Entered into a new senior secured credit facility providing for up to an aggregate amount of $5.575 billion, consisting of a $3.575 billion Term Loan Facility, a $1.0 billion Revolving Credit Facility and a $1.0 billion Letter of Credit Facility; and
  - Issued (i) $1.2 billion aggregate principal amount of 7.25% Senior Notes, and (ii) $2.4 billion aggregate principal amount of 7.375% Senior Notes.

Off-Balance Sheet Arrangements

Obligations Under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 18 to the condensed consolidated financial statements of this Form 10-Q for further details of the guarantee arrangements.

Retained or Contingent Interests

NRG does not have any material retained or contingent interests in assets transferred to an unconsolidated entity.

Derivative Instrument obligations

On August 11, 2005, NRG issued 3.625% Preferred Stock that included a conversion feature which was considered a derivative per FAS 133. Although it is considered a derivative, it was exempt from derivative accounting as it was excluded from the scope pursuant to paragraph 11(a) of FAS 133. Despite this exclusion, per the guidance of EITF Topic D-98 the conversion feature must be marked-to-market. As of September 30, 2006, the conversion feature has no value since NRG's stock price is outside the conversion range.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments — As of September 30, 2005, NRG had not entered into any financing structure that was designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to the Company. However, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting. NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $170 million as of September 30, 2006. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. In the normal course of business the Company may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and where appropriate, bear market-based interest rates.

New Synthetic Letter of Credit Facility and Revolver Facility — Under the New Senior Credit Facility NRG entered into on February 2, 2006, the Company has a $1 billion synthetic Letter of Credit Facility, and a $1 billion senior Revolving Credit Facility. The synthetic Letter of Credit Facility was secured by a $1 billion cash collateral deposit, held by Deutsche Bank AG, New York Branch as the Issuing Bank. Under the synthetic Letter of Credit Facility, NRG is allowed to issue letters of credit to support the Company's obligations under commodity hedging or power purchase arrangements. In addition, NRG is permitted to issue up to $300 million in unfunded letters of credit under the Company's Revolving Credit Facility, or revolver letters of credit, for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the New Senior Credit Facility.

As of September 30, 2006, the Company had issued $858 million in funded letters of credit under the Letter of Credit Facility. Of this amount, a portion was issued to support obligations under terminated NRG letter of credit facilities. As of September 30, 2006, the Company had issued $157 million in revolver letters of credit, a portion of which supports non-commercial letter of credit obligations under letter of credit facilities terminated as of February 2, 2006.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs, as disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2005.

See Note 15 to the condensed consolidated financial statements of this Form 10-Q for a discussion of commitments and contingencies that also include contractual obligations and commercial commitments that occurred during 2006.

Critical Accounting Policies and Estimates and Changes in Accounting Standards

NRG's discussion and analysis of the financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or GAAP, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges. These judgments, in and of themselves, could materially affect the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, NRG evaluates these estimates, utilizing historic experience, consultation with experts and other methods the Company considers reasonable. In any event, actual results may differ substantially from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Goodwill and Other Intangible Assets

As part of the acquisition of Texas Genco LLC, NRG recorded intangible assets and goodwill. The Company applied SFAS 141- *Business Combinations* and SFAS 142 — *Goodwill and Other Intangible Assets*, to account for these intangibles. Under these standards, the Company amortizes all finite-lived intangible assets over their respective estimated weighted-average useful lives; while goodwill has an indefinite life and is not amortized. However, goodwill and all intangible assets not subject to amortization will be tested for impairment whenever an event occurs that indicates that an impairment may have occurred, or at a minimum on an annual basis. Where necessary, the Company's goodwill and/or intangible asset will be impaired at that time.

In connection with the Texas Genco acquisition, the Company recognized the estimated fair value of certain power sale contracts and fuel contracts acquired. NRG estimated their fair value using forward pricing curves as of the closing date of the acquisition over the life of each contract. These contracts had negative fair values at the closing date of the acquisition and will be reflected as assumed contracts in the combined balance sheet. Assumed contracts are amortized to revenues and fuel expense as applicable based on the estimated realization of the fair value established on the closing date over the contractual lives.

The amount of goodwill as disclosed in the past has decreased due to a change in several factors since the previously reported values. These factors include:

- Earlier estimates reported were based on estimated working capital and estimated common stock prices;
- Changes in the forecasted projected prices of electricity, coal and emission allowances. These projections greatly affect the expected future cash flows from NRG Texas, as well as the value of intangibles and out of market contracts;
- The tax basis of the assets and liabilities acquired is more accurate, although still subject to revision; and
- More precise information with respect to identifiable intangibles.

Currently, NRG has valued goodwill at approximately $1.6 billion, with the appraisal of Property, Plant and Equipment increasing its fair value, compared to Texas Genco LLC's historical cost, by approximately $5.8 billion. If the remaining goodwill balance is indicative of a further increase in value of depreciable property plant and equipment, depreciation expense for the three and nine month period ended September 30, 2006, would increase by approximately $20 million and $55 million, respectively, reducing income from continuing operations before tax for the three and nine month period ended September 30, 2006 to approximately $588 million and $857 million, respectively.

See Note 1 to the condensed consolidated financial statements to this Form 10-Q for details of changes in accounting standards.

Item 3 — Quantitative and Qualitative Disclosures About Market Risk

NRG is exposed to several market risks in the Company's normal business activities. Market risk is the potential loss that may result from market changes associated with the Company's merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks the Company is exposed to are commodity price risk, interest rate risk and currency exchange risk. In order to manage these risks the Company utilizes various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets to:

- Manage and hedge fixed-price purchase and sales commitments;
- Manage and hedge exposure to variable rate debt obligations;
- Reduce exposure to the volatility of cash market prices; and
- Hedge fuel requirements for the Company's generating facilities.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatility in commodities, and correlations between various commodities, such as natural gas, electricity, coal and oil. A number of factors influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- Seasonal, daily and hourly changes in demand;
- Extreme peak demands due to weather conditions;
- Available supply resources;
- Transportation availability and reliability within and between regions; and
- Changes in the nature and extent of federal and state regulations.

As part of the NRG's overall portfolio, NRG manages the commodity price risk of the Company's merchant generation operations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel. These instruments include forward purchase and sale contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets. The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

While some of the contracts the Company uses to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. NRG uses the Company's best estimates to determine the fair value of commodity and derivative contracts held and sold. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuation, and such variations could be material.

NRG measures the sensitivity of the Company's portfolio to potential changes in market prices using value at risk. Value-at-risk, or VAR, is a statistical model that attempts to predict risk of loss based on market price volatility. The Company calculates VAR using a variance/covariance technique that models positions using a linear approximation of their value. NRG's VAR calculation includes mark-to-market and non mark-to-market energy assets and liabilities.

NRG utilizes a diversified VAR model to calculate the estimate of potential loss in the fair value of the Company's energy assets and liabilities including generation assets, load obligations and bilateral physical and financial transactions. The key assumptions for the Company's diversified model include: (1) a lognormal distribution of price returns, (2) one-day holding period, (3) a 95% confidence interval, (4) a rolling 24-month forward looking period and (5) market implied price volatilities and historical price correlations.

This model encompasses all of NRG's generating assets across the entire portfolio including NRG Texas. As of September 30, 2006 the VAR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VAR model was $49.1 million.

The following table summarizes average, maximum and minimum VAR for NRG for the three months ended September 30, 2006.

VAR	In millions
As of September 30, 2006	$ 49.1
Average for the three months ended September 30, 2006	58.1
Maximum	66.7
Minimum	49.1

Due to the inherent limitations of statistical measures such as VAR, the relative immaturity of the competitive markets for electricity and related derivatives, and the seasonality of changes in market prices, the VAR calculation may not capture the full extent of commodity price exposure. Additionally, actual changes in the value of options may differ from the VAR calculated using a linear approximation inherent in the Company's calculation methodology. As a result, actual changes in the fair value of mark-to market energy assets and liabilities could differ from the calculated VAR, and such changes could have a material impact on the Company's financial results.

In order to provide additional information for comparative purposes to NRG's peers the Company also utilizes VAR to model the estimate of potential loss of financial derivative instruments included in derivative instruments valuation of assets and liabilities. This estimation includes those energy contracts accounted for as a hedge under SFAS 133, as amended. The VAR for the financial derivative instruments calculated using the diversified VAR model as of September 30, 2006 for the entire term of these instruments was approximately $94 million.

Interest Rate Risk

NRG is exposed to fluctuations in interest rates through the Company's issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. NRG's risk management policies allow the Company to reduce interest rate exposure from variable rate debt obligations.

In January 2006, the Company entered into a series of new interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, NRG pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the equivalent of a floating interest payment based on 3-month LIBOR rate calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of May 3, 2006 was $2.15 billion. The notional amounts and maturities of each tranche of these swaps are described in Note 8 to the condensed consolidated financial statements of this Form 10-Q.

As of September 30, 2006, the Company had various interest rate swap agreements with notional amounts totaling approximately $2.8 billion. If the swaps had been discontinued on September 30, 2006, the Company would have owed the counter-parties approximately $12.6 million. Based on the investment grade rating of the counter-parties, NRG believes that the Company's exposure to credit risk due to nonperformance by the counter-parties to the hedging contracts is insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of September 30, 2006, a 100 basis point change in interest rates would result in a $18.7 million change in interest expense on a rolling twelve month basis.

As of September 30, 2006, the fair value and the carrying amount of the Company's long-term debt was $7.9 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company's long-term debt by $420 million.

Currency Exchange Risk

NRG expects to continue to be subject to currency risks associated with foreign denominated distributions from the Company's international investments. In the normal course of business, NRG may receive distributions denominated in the Euro, Australian Dollar and the Brazilian Real. NRG has historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to the extent required, fixing the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. The Company would expect to enter into similar transactions in the future if management deems it to be appropriate.

In connection with the sale of Flinders as discussed in Note 3 to the condensed consolidated financial statements of this Form 10-Q, on August 15, 2006, NRG entered into a forward foreign exchange contract to sell AU $300 million in exchange for $229 million and designated it as a fair value hedge. Due to changes in the exchange rate, NRG recognized a loss as of September 30, 2006 of approximately $5 million on its cash balance, with an offsetting gain from derivative income on the related contract. The contract was settled on October 16, 2006.

Liquidity Risk

Liquidity risk arises from the general funding needs of NRG's activities and in the management of the Company's assets and liabilities. NRG's liquidity management framework is intended to maximize liquidity access and minimize funding costs. Through active liquidity management, the Company seeks to preserve stable, reliable and cost-effective sources of funding. This enables the Company to replace maturing obligations when due and fund assets at appropriate maturities and rates. To accomplish this task, management uses a variety of liquidity risk measures that take into consideration market conditions, prevailing interest rates, liquidity needs and the desired maturity profile of liabilities.

NRG's collateral posted in support of the management of NRG's electric generation facilities fluctuates based on the amount of the portfolio hedged using collateralized contracts and market price movements. Based on a sensitivity analysis a $1 per MWh increase or decrease in electricity prices would cause a change in margin collateral outstanding of approximately $14.5 million as of September 30, 2006. This sensitivity uses simplified assumptions and may not reflect actual market movements.

Credit Risk

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. The Company monitors and manages the credit risk of NRG and its subsidiaries through credit policies which include (i) an established credit approval process, (ii) a daily monitoring of counter-party credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements, 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. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company has credit protection within various agreements to call on additional collateral support if and when necessary. As of September 30, 2006, NRG held collateral support of approximately $480 million from counterparties.

A portion of NRG's credit risk is related to transactions that are recorded in the Company's consolidated Balance Sheets. These transactions primarily consist of open positions from the Company's marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities as of September 30, 2006:

Credit Exposure (In millions, except ratios)	**Exposure Before Collateral**	**Collateral**	**Net Exposure**
Investment grade	$ 1,548	$ 384	$ 1,164
Non-investment grade	50	41	9
Not rated	156	5	151
Total	$ 1,754	$ 430	$ 1,324
Investment grade	88%	89%	88%
Non-investment grade	3%	10%	1%
Not rated	9%	1%	11%

Additionally, the Company has concentrations of suppliers and customers among coal suppliers, electric utilities, energy marketing and trading companies and regional transmission operators. These concentrations of counterparties may impact NRG's overall exposure to credit risk, either positively or negatively, in that counterparties may be similarly affected by changes in economic, regulatory and other conditions.

NRG's exposure to significant counterparties greater than 10% of the net exposure of approximately $1.3 billion was approximately $867 million as of September 30, 2006. NRG does not anticipate any material adverse effect on the Company's financial position or results of operations as a result of nonperformance by any of NRG's counterparties.

Fair Value of Derivative Instruments

As the Company engages principally in the trading and marketing of its generation assets, most of the Company's commercial activities qualify for hedge accounting under the requirements of SFAS 133. In order to so qualify, the physical generation and sale of electricity must be highly probable at inception of the trade and throughout the period it is held, as is the case with NRG's base-load coal plants. For this reason, trades in support of the Company's peaking units will not generally qualify for hedge accounting treatment and any changes in the fair value is likely to be reflected on a mark-to-market basis in the statement of operations. The majority of trades in support of NRG's baseload coal units will normally qualify for hedge accounting treatment and any fair value movements will be reflected in the balance sheet as part of other comprehensive income.

As part of the trading and marketing of NRG's generation assets, the Company may enter into forward power sales contracts, forward gas purchase contracts and other energy related commodities financial instruments to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect fuel inventories. In addition, in order to mitigate interest rate risk associated with the issuance of NRG's variable rate and fixed rate debt, the Company enters into interest rate swap agreements.

The tables below disclose the derivative contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values as at September 30, 2006 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at September 30, 2006.

Derivative Activity Gains/(Losses)	**(In millions)**
Fair value of contracts at December 31, 2005	$ (403)
Value of Flinders contracts as at December 31, 2005, included in discontinued operations	73
Value of contracts acquired with NRG Texas on February 2, 2006	(472)
Contracts realized or otherwise settled during the period	153
Changes in fair value	700
Fair value of contracts at September 30, 2006	$ 51

	Fair Value of Contracts as of September 30, 2006				
Sources of Fair Value Gains/(Losses) (In millions)	**Maturity Less than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in excess of 5 Years**	**Total Fair Value**
Prices actively quoted	$ (4)	$ (2)	$ —	$ —	$ (6)
Prices provided by other external sources	63	6	15	(27)	57
Total	$ 59	$ 4	$ 15	$ (27)	$ 51

NRG may use a variety of financial instruments to manage the Company's exposure to fluctuations in foreign currency exchange rates on NRG's international project cash flows, interest rates on the Company's cost of borrowing and energy and energy-related commodities prices.

Item 4 — Controls and Procedures

Under the supervision and with the participation of NRG's management, including the Company's principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended. Based on this evaluation, NRG's principal executive officer, principal financial officer and principal accounting officer concluded that the Company's disclosure controls and procedures are effective to ensure that the information required to be disclosed in reports filed under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

With the completion and associated integration of the acquisition of Texas Genco LLC and WCP, there have been no changes in the Company's internal control over financial reporting during the completed third quarter of 2006 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1 — Legal Proceedings

For a discussion of material legal proceedings in which NRG was involved through September 30, 2006, see Note 15 to the condensed consolidated financial statements of this Form 10-Q.

Item 1A — Risk Factors

Information regarding risk factors appears in Item 1A Risk Factors in NRG Energy, Inc.'s 2005 Annual Report on Form 10-K for the fiscal year ended December 31, 2005. There have been no material changes from the risk factors previously disclosed in NRG Energy, Inc.'s 2005 Annual Report on Form 10-K.

Item 2 — Unregistered Sales of Equity Securities and Use of Proceeds

Item 2(c) — Purchase of Equity securities by NRG

For the period ended October 13, 2006	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Dollar value of shares that may be purchased under the plans or programs
First quarter	—	—	—	—
Second quarter	—	—	—	—
July 1 – July 31	—	—	—	—
August 1 – August 31	—	—	—	$ 500,000,000
September 1 - September 30	6,113,000	$ 48.61	6,113,000	203,000,000
Third Quarter Total	6,113,000	48.61	6,113,000	
October 1 – October 13, 2006	4,474,700	45.32	10,587,700	—
Year-to-date	10,587,700	47.22	10,587,700	

During the third quarter 2006, NRG repurchased 6,113,000 common shares at an average price per share of $48.61 in connection with a share repurchase program announced on August 1, 2006. On October 13, 2006, NRG completed Phase I of the share repurchase program with a total of 10,587,700 shares of common stock repurchased at an average price per share of $47.22.

Item 3 — Defaults Upon Senior Securities

None.

Item 4 — Submission of Matters to a Vote of Security Holders

None

Item 5 — Other Information

On November 3, 2006, NRG announced its intention to enter into a series of transactions that includes (i) the reset of existing out-of-the-money hedges for years 2006 through 2010 to market, (ii) substantial new baseload hedges for the years 2010 and 2011 and, possibly, later years, (iii) the issuance of $1.1 billion of new high yield notes and (iv) amendments to NRG's existing Senior Credit Facility, including the increase of the synthetic letter of credit facility by $500 million. Except as otherwise noted, all of these transactions are expected to close by November 21, 2006.

The Hedge Reset include amendments to the Amended and Restated Master Power Purchase Agreement dated February 2, 2006, between J. Aron & Company, or J. Aron, and Texas Genco II, LP (including the cover sheet and confirmations letter thereto). The Amended Agreement provides among other things, for the amendment of the prices to be paid by J. Aron to reflect current market prices for power and for the payment by NRG of cash in an amount reflecting a negotiated present value of the difference between the original price in the agreement and the amended price.

Item 6 — Exhibits

(a) Exhibits

10.1	Limited Liability Company Agreement of NRG Common Stock Finance I LLC. (1)
10.2	Limited Liability Company Agreement of NRG Common Stock Finance II LLC. (1)
10.3	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC. (1)
10.4	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance II LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC, as agent. (1)
10.5	Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent. (1)
10.6	Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance II LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent. (1)
10.7	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC. (1)
10.8	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance II LLC. (1)
10.9	Common Interest Purchase Agreement, dated August 4, 2006, between NRG Energy, Inc. and NRG Common Stock Finance I LLC. (1)
10.10	Common Interest Purchase Agreement, dated August 4, 2006, between NRG Energy, Inc. and NRG Common Stock Finance II LLC. (1)
10.11	Underwriting Agreement, dated as of August 4, 2006, by and among NRG Energy, Inc., Credit Suisse International, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC. (1)
10.12	Underwriting Agreement, dated as of August 9, 2006, among NRG Energy, Inc., affiliates of The Blackstone Group, Hellman & Friedman, Kohlberg Kravis Roberts & Co. and Texas Pacific Group, as selling stockholders, and Morgan Stanley & Co. Incorporated, as underwriter. (2)
10.13	Underwriting Agreement, dated as of August 23, 2006, among NRG Energy, Inc., affiliates of Kohlberg Kravis Roberts & Co., as selling stockholders, and Morgan Stanley & Co. Incorporated, as underwriter. (3)
10.14	Underwriting Agreement, dated as of August 23, 2006, among NRG Energy, Inc., affiliates of Texas Pacific Group, as selling stockholders, and Morgan Stanley & Co., Incorporated, as underwriter. (3)
12.1	Computation of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.3	Certification of Controller pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
32	Certification of Chief Executive Officer, Chief Financial Officer and Controller pursuant to Section 906 of the Sarbanes- Oxley Act of 2002, 18 U.S.C. Section 1350, filed herewith.

(1) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 10, 2006.

(2) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 11, 2006.

(3) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 25, 2006.

SIGNATURES

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

NRG ENERGY, INC.
(Registrant)

/s/ DAVID CRANE
David Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON
Robert C. Flexon,
Chief Financial Officer
(Principal Financial Officer)

/s/ CAROLYN J. BURKE
Carolyn J. Burke,
Controller
(Principal Accounting Officer)

Date: November 6, 2006

Exhibit Index

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(2) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 11, 2006.

(3) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 25, 2006.

EXHIBIT 12.1

NRG Energy, Inc.
Computation Ratio of Earnings to Fixed Charges

(In millions except for ratios)	For the Year Ended December 31, 2001	For the Year Ended December 31, 2002	For the Period January 1, 2003 Through December 5, 2003	For the Period December 6, 2003 Through December 31, 2003	For the Year Ended December 31, 2004	For the Year Ended December 31, 2005	For the Nine Months Ended September 30, 2005	For the Nine Months Ended September 30, 2006
Earnings:								
Income/(loss) before taxes from continuing operations before income tax	$ 251	$ (2,955)	$ 3,120	$ 10	$ 226	$ 120	$ 20	$ 912
Minority interest in earnings				—	—	—		
Less:								
Undistributed equity in (earnings)/losses of unconsolidated affiliates	(119)	(22)	(41)	2	(1)	(8)	1	(27)
Capitalized interest	(27)	(46)	—	—	—	—	—	(4)
Add:								
Fixed charges	394	502	312	19	270	200	143	427
Total Earnings/(Losses):	$ 499	$ (2,521)	$ 3,391	$ 31	$ 495	$ 312	$ 164	$ 1,308
Fixed Charges:								
Interest expense	$ 353	$ 424	$ 290	$ 16	$ 239	$ 186	$ 133	$ 400
Interest capitalized	27	46	—	—	—	—	—	4
Amortization of debt issuance costs	11	28	18	1	9	6	4	15
Amortization of debt discount	—	—	—	2	18	5	4	5
Approximation of interest in rental expense	3	4	4	0	4	3	2	3
Total Fixed Charges:	$ 394	$ 502	$ 312	$ 19	$ 270	$ 200	$ 143	$ 427
Ratio of Earnings/(Losses) to combined Fixed Charges	1.27	—(1)	10.87	1.62	1.83	1.56	1.15	3.06

(1) Earnings did not cover fixed charges.

EXHIBIT 31.1

CERTIFICATION

I, David Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID CRANE
David Crane
Chief Executive Officer
(Principal Executive Officer)

Date: November 6, 2006

EXHIBIT 31.2

CERTIFICATION

I, Robert C. Flexon, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ROBERT C. FLEXON

Robert C. Flexon
Chief Financial Officer
(Principal Financial Officer)

Date: November 6, 2006

EXHIBIT 31.3

CERTIFICATION

I, Carolyn J. Burke, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CAROLYN J. BURKE
Carolyn J. Burke
Controller
(Principal Accounting Officer)

Date: November 6, 2006

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of NRG Energy, Inc. on Form 10-Q for the quarter ended September 30, 2006, as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-Q"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Form 10-Q.

Date: November 6, 2006

/s/ DAVID CRANE
David Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON
Robert C. Flexon,
Chief Financial Officer
(Principal Financial Officer)

/s/ CAROLYN J. BURKE
Carolyn J. Burke,
Controller
(Principal Accounting Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NRG Energy, Inc. and will be retained by NRG Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.