NRG ENERGY, INC.
Form 10-Q
August 02, 2007

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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
**FORM 10-Q**

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

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

**For the quarterly period ended: June 30, 2007** **Commission File Number: 001-15891**

**NRG Energy, Inc.**
(Exact name of Registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such 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** þ **No** o

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 þ** **Accelerated filer o** **Non-accelerated filer o**

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

**Yes** o **No** þ

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** þ **No** o

As of July 30, 2007, there were 239,833,005 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 , exp 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, or NRG s, actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Risks Related to NRG in Part I, Item 1A, of the Company s Annual Report on Form 10-K and Part II, Item 1A, of NRG s Quarterly Report on Form 10-Q 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 may not have adequate insurance to cover losses as a result of such hazards;

The effectiveness of NRG s risk management policies and procedures, and the ability of NRG s counterparties to satisfy their financial commitments;

Counterparties collateral demands and other factors affecting NRG s liquidity position and financial condition;

NRG s ability to operate its businesses efficiently, manage capital expenditures and costs tightly (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 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 ISOs, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate NRG s generation units for all of its costs;

NRG s ability to borrow additional funds and access capital markets, as well as NRG s substantial indebtedness and the possibility that NRG may incur additional indebtedness going forward;

Operating and financial restrictions placed on NRG contained in the indentures governing NRG s outstanding notes in NRG s senior credit facility and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;

NRG s ability to implement its *RepoweringNRG* strategy of developing and building new power generation facilities, including new nuclear units and Integrated Gasification Combined Cycle, or IGCC, units; and

NRG s ability to achieve the expected benefits of the Comprehensive Capital Allocation Plan and Holdco structure.

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

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# 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, now referred to as the Company s Texas region |
| ARO | Asset Retirement Obligation |
| Baseload capacity | Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year |
| BTU | British Thermal Unit |
| CAISO | California Independent System Operator |
| Capital Allocation Program | Share repurchase program entered into in August 2006 |
| CDD | Cooling Degree Day It represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in a region |
| CDWR | California Department of Water Resources |
| CL&P | Connecticut Light & Power |
| $CO_2$ | Carbon Dioxide |
| Comprehensive Capital Allocation Plan | A comprehensive plan to support and facilitate NRG s capital allocation strategy that includes a holding company structure to enable the distribution of a cash dividend on NRG s common stock, the pay down of debt, a stock split, and the Capital Allocation Program |
| CPUC | California Public Utilities Commission |
| DOJ | Department of Justice |
| DNREC | Delaware Department of Natural Resources and Environmental Control |
| EAB | Environmental Appeals Board |
| EFOR | Equivalent Forced Outage Rates considers the equivalent impact that forced de-ratings have in addition to full forced outages |
| EPC | Engineering, Procurement and Construction |
| ERCOT | Electric Reliability Council of Texas, the Independent System Operator and regional reliability coordinator of the various electricity systems within Texas |
| FASB | Financial Accounting Standards Board, the designated organization for establishing standards for financial accounting and reporting |
| FERC | Federal Energy Regulatory Commission |
| FIN | FASB Interpretation |
| GAAP | Accounting principles generally accepted in the United States |
| HDD | Heating Degree Day It represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in a region |
| Hedge Reset | Net settlement of long-term power contracts and gas swaps by negotiating prices to current market completed in November 2006 |
| ICAP | Installed Capacity |
| IGCC | Integrated Gasification Combined Cycle |
| ISO | Independent System Operator, also referred to as Regional Transmission Organization, or RTO |
| ITISA | Itiquira Energetica S.A. |
| kW | Kilowatts |
| LFRM | Locational Forward Reserve Market |
| LIBOR | London Inter-Bank Offered Rate |
| Merit Order | |

| | |
|---|---|
| | A term used for the ranking of power stations in terms of increasing order of fuel costs |
| MMBtu | Million British Thermal Units |
| MW | Megawatts |
| MWh | Saleable megawatt hours net of internal/parasitic load |
| NEPOOL | New England Power Pool |
| New Investment | The value of NRG s investment in West Coast Power (Generation) Holdings, LLC. on March 31, 2006 |
| New York Rest of State | New York State excluding New York City |
| NiMo | Niagara Mohawk Power Corporation |
| $NO_x$ | Nitrogen oxide |
| NOL | Net Operating Loss |
| NOV | Notice of Violation |
| NPNS | Normal Purchase Normal Sale |
| NQSO | Non-Qualified Stock Options |
| NSR | Non-Spinning Reserve |

**GLOSSARY OF TERMS (cont d)**

| | |
|---|---|
| NYISO | New York Independent System Operator |
| OCI | Other Comprehensive Income |
| Original Investment | The value of NRG investment in WCP (Generation) Holdings, LLC before March 31, 2006. |
| Phase II 316(b) Rule | A section of the Clean Water Act regulating cooling water intake structures |
| PJM | 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 | NRG Power Marketing, Inc., a wholly-owned subsidiary of NRG which procures transportation and fuel for NRG s generation facilities, sells the power from these facilities, and manages all commodity trading and hedging for NRG |
| PPA | Power Purchase Agreement |
| PRB | Powder River Basin |
| PU | Performance Units |
| PUCT | Public Utility Commission of Texas |
| *RepoweringNRG* | Our program designed to develop, finance, construct and operate over 10,000 MW of new, highly efficient, environmentally responsible capacity over the next decade, at an estimated total cost of approximately $16 billion. |
| Revolving Credit Facility | NRG s $1 billion senior secured revolving credit facility which matures on February 2, 2011 |
| RMR | Reliability Must-Run |
| RPM | Reliability Pricing Model |
| RSU | Restricted Stock Units |
| RTO | Regional Transmission Organization, also referred to as an ISO |
| SEC | United States Securities and Exchange Commission |
| Senior Credit Facility | NRG s senior secured facility, which is comprised of a $3.1 billion Term B loan facility which matures on February 1, 2013, its $1.3 billion Synthetic Letter of Credit Facility, and its $1 billion Revolving Credit Facility |
| SERC | Southeastern Electric Reliability Council/Entergy |
| SFAS | Statement of Financial Accounting Standards issued by the FASB |
| SFAS 5 | SFAS No. 5, *Accounting for Contingencies* |
| SFAS 71 | SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* |
| SFAS 109 | SFAS No. 109, *Accounting for Income Taxes* |
| SFAS 133 | SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* |
| $SO_2$ | Sulfur Dioxide |
| SOP | Statement of Position issued by the American Institute of Certified Public Accountants |
| STP | South Texas Project Nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest |
| Synthetic Letter of Credit Facility | NRG s $1.3 billion senior secured synthetic letter of credit facility which matures on February 1, 2013 |
| Term B loan | $3.1 billion bank term loan included as part of NRG s Senior Credit Facility |
| TEP | Temporary Extraordinary Operating Procedures |
| Texas Genco | Texas Genco LLC, now referred to as the Company s Texas region |
| TWCC | Texas Westmoreland Coal Company |
| U.S. | United States of America |

| | |
|---|---|
| USEPA0 | United States Environmental Protection Agency |
| VAR | Value at Risk |
| WCP | WCP (Generation) Holdings, LLC |

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## Part I FINANCIAL INFORMATION

### Item 1 Condensed Consolidated Financial Statements and Notes

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **(In millions, except for per share amounts)** | **2007** | **2006** | **2007** | **2006** |
| **Operating Revenues** | | | | |
| Total operating revenues | $ 1,548 | $ 1,502 | $ 2,858 | $ 2,537 |
| **Operating Costs and Expenses** | | | | |
| Cost of operations | 843 | 832 | 1,627 | 1,482 |
| Depreciation and amortization | 161 | 177 | 322 | 295 |
| General and administrative | 71 | 83 | 157 | 141 |
| Development costs | 36 | | 59 | |
| Total operating costs and expenses | 1,111 | 1,092 | 2,165 | 1,918 |
| Gain/(loss) on sale of assets | (1) | | 16 | |
| **Operating Income** | 436 | 410 | 709 | 619 |
| **Other Income/(Expense)** | | | | |
| Equity in earnings of unconsolidated affiliates | 8 | 8 | 21 | 29 |
| Write downs and gains on sales of equity method investments | 1 | 14 | 1 | 11 |
| Other income, net | 14 | 8 | 30 | 88 |
| Refinancing expense | (35) | | (35) | (178) |
| Interest expense | (174) | (151) | (355) | (266) |
| Total other expense | (186) | (121) | (338) | (316) |
| **Income From Continuing Operations Before Income Taxes** | 250 | 289 | 371 | 303 |
| Income Tax Expense | 101 | 87 | 157 | 86 |
| **Income From Continuing Operations** | 149 | 202 | 214 | 217 |
| Income from discontinued operations, net of income tax expense | | 1 | | 12 |
| **Net Income** | 149 | 203 | 214 | 229 |
| Dividends for Preferred Shares | 14 | 13 | 28 | 23 |
| **Income Available for Common Stockholders** | $ 135 | $ 190 | $ 186 | $ 206 |
| Weighted Average Number of Common Shares Outstanding Basic | 240 | 274 | 241 | 255 |

| | | | | |
|---|---|---|---|---|
| Income From Continuing Operations per Weighted Average Common Share Basic | $ 0.56 | $ 0.69 | $ 0.77 | $ 0.75 |
| Income From Discontinued Operations per Weighted Average Common Share Basic | | | | 0.05 |
| **Net Income per Weighted Average Common Share Basic** | $ 0.56 | $ 0.69 | $ 0.77 | $ 0.80 |
| Weighted Average Number of Common Shares Outstanding Diluted | 288 | 319 | 273 | 295 |
| Income From Continuing Operations per Weighted Average Common Share Diluted | $ 0.51 | $ 0.63 | $ 0.71 | $ 0.72 |
| Income From Discontinued Operations per Weighted Average Common Share Diluted | | | | 0.04 |
| **Net Income per Weighted Average Common Share Diluted** | $ 0.51 | $ 0.63 | $ 0.71 | $ 0.76 |

See notes to condensed consolidated financial statements.

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## NRG ENERGY, INC. AND SUBSIDIARIES
## CONDENSED CONSOLIDATED BALANCE SHEETS

| (in millions, except for share data) | June 30, 2007 (unaudited) | December 31, 2006 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 795 | $ 795 |
| Restricted cash | 52 | 44 |
| Accounts receivable, less allowance for doubtful accounts of $1 and $1 | 564 | 372 |
| Inventory | 430 | 421 |
| Derivative instruments valuation | 810 | 1,230 |
| Deferred income taxes | 62 | |
| Prepayments and other current assets | 284 | 221 |
| Total current assets | 2,997 | 3,083 |
| **Property, plant and equipment, net of accumulated depreciation of $1,334 and $984** | 11,454 | 11,600 |
| **Other Assets** | | |
| Equity investments in affiliates | 371 | 344 |
| Notes receivable and capital lease, less current portion | 474 | 479 |
| Goodwill | 1,785 | 1,789 |
| Intangible assets, net of accumulated amortization of $319 and $259 | 931 | 981 |
| Nuclear decommissioning trust fund | 377 | 352 |
| Derivative instruments valuation | 203 | 439 |
| Deferred income taxes | 29 | 27 |
| Other non-current assets | 210 | 262 |
| Intangible assets held-for-sale | 105 | 79 |
| Total other assets | 4,485 | 4,752 |
| **Total Assets** | $ 18,936 | $ 19,435 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| **Current Liabilities** | | |
| Current portion of long-term debt and capital leases | $ 126 | $ 130 |
| Accounts payable | 383 | 332 |
| Derivative instruments valuation | 687 | 964 |
| Deferred income taxes | | 164 |
| Accrued expenses and other current liabilities | 449 | 442 |
| Total current liabilities | 1,645 | 2,032 |
| **Other Liabilities** | | |
| Long-term debt and capital leases | 8,609 | 8,647 |

| | | | | |
|---|---|---|---|---|
| Nuclear decommissioning reserve | | 298 | | 289 |
| Nuclear decommissioning trust liability | | 335 | | 324 |
| Deferred income taxes | | 713 | | 554 |
| Derivative instruments valuation | | 562 | | 351 |
| Out-of-market contracts | | 768 | | 897 |
| Other non-current liabilities | | 425 | | 435 |
| Total non-current liabilities | | 11,710 | | 11,497 |
| **Total Liabilities** | | 13,355 | | 13,529 |
| Minority Interest | | 1 | | 1 |
| 3.625% Redeemable perpetual preferred stock (at liquidation value, net of issuance costs) | | 247 | | 247 |
| **Commitments and Contingencies** | | | | |
| **Stockholders Equity** | | | | |
| Preferred stock (at liquidation value, net of issuance costs) | | 892 | | 892 |
| Common Stock | | 3 | | 1 |
| Additional paid-in capital | | 4,028 | | 4,476 |
| Retained earnings | | 925 | | 739 |
| Less treasury stock, at cost 21,175,400 and 29,601,162 shares | | (500) | | (732) |
| Accumulated other comprehensive income/(loss) | | (15) | | 282 |
| **Total Stockholders Equity** | | 5,333 | | 5,658 |
| **Total Liabilities and Stockholders Equity** | $ | 18,936 | $ | 19,435 |

See notes to condensed consolidated financial statements.

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

| (In millions) Six months ended June 30, | 2007 | 2006 |
|---|---|---|
| **Cash Flows from Operating Activities** | | |
| Net income | $ 214 | $ 229 |
| Adjustments to reconcile net income to net cash provided by operating activities | | |
| Distributions less than equity in earnings of unconsolidated affiliates | (7) | (13) |
| Depreciation and amortization of nuclear fuel | 348 | 308 |
| Amortization and write-off of financing costs and debt discount/premiums | 51 | 63 |
| Amortization of intangibles and out-of-market contracts | (73) | (211) |
| Amortization of unearned equity compensation | 14 | 9 |
| Changes in deferred income taxes | 142 | 96 |
| Changes in derivatives | 47 | (41) |
| Changes in nuclear decommissioning trust liability | 20 | 3 |
| Changes in collateral deposits supporting energy risk management activities | (103) | 272 |
| Gain on legal settlement | | (67) |
| Gain on sale of emission allowances | (24) | (67) |
| (Gain)/loss on sale of assets | (16) | 3 |
| Gain on sale of discontinued operations | | (10) |
| Write down and gains on sale of equity method investments | (1) | (11) |
| Cash provided/(used) by changes in other working capital, net of acquisition and disposition affects | (153) | 114 |
| **Net Cash Provided by Operating Activities** | 459 | 677 |
| **Cash Flows from Investing Activities** | | |
| Acquisition of Texas Genco LLC, and WCP, net of cash acquired | | (4,328) |
| Capital expenditures | (205) | (74) |
| Increase in restricted cash, net | (8) | (9) |
| Decrease in notes receivable | 17 | 14 |
| Purchases of emission allowances | (135) | (78) |
| Proceeds from sale of emission allowances | 131 | 84 |
| Investments in nuclear decommissioning trust fund securities | (140) | (106) |
| Proceeds from sale of nuclear decommissioning trust fund securities | 120 | 103 |
| Proceeds from sale of assets | 29 | 1 |
| Proceeds from sale of investments | 2 | 86 |
| Decrease in trust fund balances | 13 | |
| Investments in marketable securities | 4 | |
| Proceeds from sale of discontinued operations | | 15 |
| **Net Cash Used by Investing Activities** | (172) | (4,292) |
| **Cash Flows from Financing Activities** | | |
| Payment of dividends to preferred stockholders | (28) | (23) |
| Payment of financing element of acquired derivatives | | (73) |

| | | |
|---|---|---|
| Payment for treasury stock | (215) | |
| 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 |
| Proceeds from issuance of long-term debt | 1,411 | 7,175 |
| Payment of deferred debt issuance costs | | (164) |
| Payments for short and long-term debt | (1,459) | (4,662) |
| **Net Cash Provided/(Used) by Financing Activities** | (291) | 4,075 |
| Change in Cash from Discontinued Operations | | 2 |
| Effect of Exchange Rate Changes on Cash and Cash Equivalents | 4 | 3 |
| **Net Increase in Cash and Cash Equivalents** | | 465 |
| **Cash and Cash Equivalents at Beginning of Period** | 795 | 493 |
| **Cash and Cash Equivalents at End of Period** | $ 795 | $ 958 |

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., or NRG or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is 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 trading of energy, capacity and related products in the United States and certain international markets.

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the United States Securities and Exchange Commission s, or SEC s, regulations for interim financial information and with the instructions to Form 10-Q. Accordingly, they do not include all of the information and notes required by generally accepted accounting principles for complete financial statements. The accounting policies NRG follows are set forth in Note 2, *Summary of Significant Accounting Policies*, to the Company s consolidated financial statements in its Annual Report on Form 10-K for the year ended December 31, 2006. The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly the Company s consolidated financial position as of June 30, 2007, results of operations for the three and six months ended June 30, 2007 and 2006, and cash flows for the six months ended June 30, 2007 and 2006. Certain prior-year amounts have been reclassified for comparative purposes.

***Stock Split***

On April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. All share and per share amounts in the consolidated results of operations and financial position as well as in the notes to the financial statements retroactively reflect the effect of the stock split.

***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.

***Recent Accounting Developments***

In April 2007, the Financial Accounting Standards Board, or FASB, issued FASB Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39*, or FSP FIN 39-1, which amends FIN 39, *Offsetting of Amounts Related to Certain Contracts*. FSP FIN 39-1 impacts entities that enter into master netting arrangements as part of their derivative transactions. Under the guidance in this new FSP, entities may choose to offset derivative positions in the financial statements against the fair value of amounts recognized as cash collateral paid or received under those arrangements. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. Entities that choose to change their accounting policy upon adoption of FSP FIN 39-1 shall recognize the effects retrospectively for all financial statements presented. The Company does not presently offset derivative positions under master netting arrangement under FIN 39 or FSP FIN 39-1 and is assessing the impact that implementing FIN 39 and FSP FIN 39-1 may have on its consolidated financial position.

The Company adopted FASB Interpretation Number 48, Accounting for Uncertainty in Income Taxes *an interpretation of FASB Statement No. 109*, or FIN 48, on January 1, 2007. FIN 48 applies to all tax positions related to income taxes subject to SFAS 109, and requires a new evaluation process for all tax positions taken, recognizing tax benefits when it is more likely than not that a tax position will be sustained upon examination by the authorities. The benefit from a position that has surpassed the more likely than

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not threshold is the largest amount of benefit that is more than 50% likely to be realized upon settlement. The adoption of FIN 48 did not have a material impact on the Company s financial position, results of operations and cash flows. The Company recognizes interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense.

**Note 2 Comprehensive Income/(Loss)**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **(In millions)** | **2007** | **2006** | **2007** | **2006** |
| Net Income | $ 149 | $ 203 | $ 214 | $ 229 |
| Unrealized gain/(loss) from derivative activity | (41) | 57 | (324) | 304 |
| Foreign currency translation adjustment | 15 | 34 | 25 | 37 |
| Gain on available-for-sale securities | 2 | | 2 | |
| Other comprehensive income/(loss), net of tax | $ (24) | $ 91 | $ (297) | $ 341 |
| Comprehensive income/(loss) | $ 125 | $ 294 | $ (83) | $ 570 |

Accumulated other comprehensive income/(loss) as of June 30, 2007 was as follows:

| **(In millions)** | |
|---|---|
| Accumulated other comprehensive income as of December 31, 2006 | $ 282 |
| Unrealized loss from derivative activity | (324) |
| Foreign currency translation adjustments | 25 |
| Gain on available-for-sale securities | 2 |
| Accumulated other comprehensive loss as of June 30, 2007 | $ (15) |

**Note 3 Business Acquisitions and Dispositions**

***Acquisition of Remaining 50% interest in WCP***

On March 31, 2006, NRG completed purchase and sale agreements for projects co-owned with Dynegy, Inc. Under the agreements, NRG acquired Dynegy s 50% ownership interest in WCP (Generation) Holdings, LLC., or WCP, for $205 million in cash and the assumption of a $1 million liability, with NRG becoming the sole owner of WCP s 1,825 MW of generation capacity in Southern California. In addition, NRG sold to Dynegy the Company s 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 fair value sale price of $45 million, paying Dynegy a net purchase price of $160 million at closing. Prior to the purchase, NRG s existing investment in WCP, the Original Investment, was accounted for as an equity method 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 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 the book value of approximately $159 million as of the date of the acquisition of the New Investment.

The value of the New Investment was allocated based on the fair value of assets acquired and liabilities assumed as of March 31, 2006. The purchase price allocation reflected an excess of fair value of the net assets acquired over the purchase price of the New Investment, resulting in negative goodwill of approximately $48 million. The negative goodwill was subsequently allocated as a reduction to the fair value of WCP s fixed and intangible assets.

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The following summarizes the 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 | Purchase Price Allocation |
| Current assets | $ 149 | $ 153 | $ | $ 153 | $ 302 |
| Property, plant and equipment | 24 | 103 | (38) | 65 | 89 |
| Intangible assets | 2 | 26 | (10) | 16 | 18 |
| Other non-current assets | | 9 | | 9 | 9 |
| Current liabilities | (13) | (18) | | (18) | (31) |
| Non-current liabilities | (3) | (19) | | (19) | (22) |
| Negative goodwill | | (48) | 48 | | |
| Total Equity | $ 159 | $ 206 | $ | $ 206 | $ 365 |

***Other Business Events***

*Red Bluff and Chowchilla* On January 3, 2007, NRG completed the sale of the Company s Red Bluff and Chowchilla II power plants to an entity controlled by Wayzata Investment Partners LLC. These power plants, located in California, are fueled by natural gas, with generating capacity of 45 MW and 49 MW, respectively. The sale resulted in a pre-tax gain of approximately $18 million.

**Note 4 Discontinued Operations**

NRG has classified material business operations and gains/losses recognized on sale as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for the affected businesses have been accounted for as discontinued operations. Accordingly, prior periods have been recast to report those operations as discontinued.

NRG had no business operations that were classified as discontinued operations for the three and six months ended June 30, 2007. For the three and six months ended June 30, 2006, discontinued operations consisted of activity related to the Company s Flinders and Audrain operations.

Summarized results of operations of discontinued entities were as follows:

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| (In millions) | 2007 | 2006 | 2007 | 2006 |
| Operating revenues | $ | $ 77 | $ | $ 145 |
| Pre-tax income from operations of discontinued operations | | 1 | | 3 |
| Income from discontinued operations, net of income taxes | | 1 | | 12 |

**Note 5 Nuclear Decommissioning Trust Fund**

NRG s nuclear decommissioning trust fund assets which are for the decommissioning of South Texas Project, or STP, are primarily comprised of securities recorded at fair value based on actively quoted market prices. NRG accounts for these trust fund assets per SFAS 71, Accounting for the Effects of Certain Types of Regulation, because the Company s nuclear decommissioning activities are regulated by the Public Utility Commission of Texas, or PUCT. Although the owners of STP are responsible for the management of decommissioning STP, the cost of decommissioning is the responsibility of the Texas ratepayers. As such, NRG does not bear the cost for these decommissioning responsibilities, except to the extent that NRG has a prudence obligation with respect to the management of the trust funds or the future decommissioning of STP. Third party appraisals are periodically conducted to estimate the future decommissioning liability related to STP. These appraisals are then used to determine the adequacy of the existing decommissioning trust investments to cover that estimated future liability. Should there be a shortfall in the value of the assets in the trust relative to the estimated liability, NRG has the ability to file a rate case with the PUCT to increase decommissioning reimbursements over time from retail customers. As of June 30, 2007, NRG believes the trust funds are adequately funded.

The following table summarizes the fair values of the securities held in the trust funds as of June 30, 2007 and December 31, 2006:

| (In millions) As of | June 30, 2007 | December 31, 2006 |
|---|---|---|
| Cash and cash equivalents | $ 5 | $ 7 |
| U.S. government and federal agency obligations | 24 | 29 |
| Federal agency mortgage-backed securities | 51 | 41 |
| Commercial mortgage-backed securities | 19 | 16 |
| Other debt securities | 41 | 43 |
| Marketable equity securities | 237 | 216 |
| Total | $ 377 | $ 352 |

**Note 6 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 unless they qualify for a Normal Purchase Normal Sale, or NPNS, exception. 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 to Other Comprehensive Income, or OCI, and subsequently recognize in earnings when the hedged transaction occurs. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

***Accumulated OCI***

The following table summarizes the effects of SFAS 133 on NRG s accumulated OCI balance attributable to hedged derivatives for the three months ended June 30, 2007, net of tax:

| (In millions) | Energy Commodities | Interest Rate | Total |
|---|---|---|---|
| Accumulated OCI balance at March 31, 2007 | $ (83) | $ 9 | $ (74) |
| Realized from OCI during the period: | | | |
| Due to realization of previously deferred amounts | (10) | | (10) |
| Mark-to-market of hedge contracts | (52) | 21 | (31) |
| Accumulated OCI balance at June 30, 2007 | $ (145) | $ 30 | $ (115) |
| Gains expected to be realized from OCI during the next 12 months | $ 30 | $ 1 | $ 31 |

The following table summarizes the effects of SFAS 133 on NRG s accumulated OCI balance attributable to hedged derivatives for the six months ended June 30, 2007, net of tax:

| (In millions) | Energy Commodities | Interest Rate | Total |
|---|---|---|---|
| Accumulated OCI balance at December 31, 2006 | $ 193 | $ 16 | $ 209 |
| Realized from OCI during the period: | | | |
| Due to realization of previously deferred amounts | (27) | | (27) |
| Mark-to-market of hedge contracts | (311) | 14 | (297) |

| | | | |
|---|---|---|---|
| Accumulated OCI balance at June 30, 2007 | $ (145) | $ 30 | $ (115) |

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

| **(In millions)** | **Energy Commodities** | **Interest Rate** | **Total** |
|---|---|---|---|
| Accumulated OCI balance at March 31, 2006 | $ 3 | $ 48 | $ 51 |
| Realized from OCI during the period: | | | |
| Due to realization of previously deferred amounts | 7 | (1) | 6 |
| Mark-to-market of hedge contracts | 19 | 32 | 51 |
| Accumulated OCI balance at June 30, 2006 | $ 29 | $ 79 | $ 108 |

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The following table summarizes the effects of SFAS 133 on NRG s accumulated OCI balance attributable to hedged derivatives for the six months ended June 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 | 27 | (3) | 24 |
| Mark-to-market of hedge contracts | 206 | 74 | 280 |
| Accumulated OCI balance at June 30, 2006 | $ 29 | $ 79 | $ 108 |

As of June 30, 2007, the net balance in OCI relating to SFAS 133 was an unrecognized loss of approximately $115 million, which is net of $77 million in income taxes. NRG expects $31 million of net deferred gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

***Statement of Operations***

In accordance with SFAS 133, unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of non-hedge derivatives or derivative activities that do not qualify as hedges, and ineffectiveness of hedge derivatives on NRG s statement of operations for the three months ended June 30, 2007:

| (In millions) | Energy Commodities | Interest Rate | Total |
|---|---|---|---|
| Revenue from majority-owned subsidiaries | $ 43 | $ | $ 43 |
| Equity in earnings of unconsolidated subsidiaries | | | |
| Cost of operations | | | |
| Interest Expense | | | |
| Total statement of operations impact before tax | $ 43 | $ | $ 43 |

The following table summarizes the pre-tax effects of non-hedge derivatives or derivative activities that do not qualify as hedges, and ineffectiveness of hedge derivatives on NRG s statement of operations for the six months ended June 30, 2007:

| (In millions) | Energy Commodities | Interest Rate | Total |
|---|---|---|---|
| Revenue from majority-owned subsidiaries | $ (47) | $ | $ (47) |
| Equity in earnings of unconsolidated subsidiaries | | | |
| Cost of operations | | | |
| Interest expense | | | |
| Total statement of operations impact before tax | $ (47) | $ | $ (47) |

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

| **(In millions)** | **Energy Commodities** | **Interest Rate** | **Total** |
|---|---|---|---|
| Revenue from majority-owned subsidiaries | $ 67 | $ | $ 67 |
| Equity in earnings of unconsolidated subsidiaries | | | |
| Cost of operations | | | |
| Interest expense | | | |
| Total statement of operations impact before tax | $ 67 | $ | $ 67 |

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

| (In millions) | Energy Commodities | Interest Rate | Total |
|---|---|---|---|
| Revenue from majority-owned subsidiaries | $ 117 | $ | $ 117 |
| Equity in earnings of unconsolidated subsidiaries | | | |
| Cost of operations | | | |
| Interest expense | | 3 | 3 |
| Total statement of operations impact before tax | $ 117 | $ (3) | $ 114 |

For the three months ended June 30, 2007, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $43 million was comprised of $100 million of fair value increases in forward sales of electricity and fuel, a $21 million net loss due to the ineffectiveness associated with financial forward electric and gas sales, and a $43 million loss from the reversal of mark-to-market gains which ultimately settled as financial revenues of which $35 million was related to economic hedges and $8 million was related to trading activity. In addition, the Company recorded $7 million of gains associated with open positions related to trading activity.

For the six months ended June 30, 2007, the unrealized loss associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $47 million was comprised of $21 million of fair value increases in forward sales of electricity and fuel, a $23 million gain due to the ineffectiveness associated with financial forward electric and gas sales, and a $113 million loss from the reversal of mark-to-market gains which ultimately settled as financial revenues of which $92 million was related to economic hedges and $21 million was related to trading activity. In addition, the Company recorded $22 million of gains associated with open positions related to trading activity.

For the three months ended June 30, 2006, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $67 million was comprised of $7 million of fair value decreases in forward sales of electricity and fuel, a $52 million gain due to the ineffectiveness associated with financial forward electric and gas sales, and $17 million from the reversal of mark-to-market losses which ultimately settled as financial revenues, of which $20 million was related to losses on economic hedges and $3 million was related to gains on trading activity. In addition, the Company recorded $5 million of gains associated with open positions related to trading activity.

For the six months ended June 30, 2006, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $117 million was comprised of $31 million of fair value increases in forward sales of electricity and fuel, a $44 million gain due to the ineffectiveness associated with financial forward electric and gas sales, and a $38 million gain from the reversal of mark-to-market losses which ultimately settled as financial revenues, of which $65 million was related to losses on economic hedges and $27 million was related to gains on trading activity. In addition, the Company recorded $4 million of gains associated with open positions related to trading activity. NRG s pre-tax earnings were also affected by a $3 million loss due to ineffectiveness associated with the Company s fixed-to-floating interest rate swap which was designated as a hedge of fair value changes in the Company s Senior Notes.

**Note 7 Long Term Debt**

On May 2, 2007, NRG announced plans for a Comprehensive Capital Allocation Plan to support a fixed and variable structure for the return of capital to stockholders. If fully implemented, this plan will provide the Company with the ability to (i) initiate an annual cash dividend the fixed component, and (ii) to continue the Company s historical program of common share repurchases the variable component.

Upon completion of the contemplated Comprehensive Capital Allocation Plan:

- NRG would become a wholly owned operating subsidiary of a newly created holding company, NRG Holdings, Inc or Holdco, with the stockholders of NRG becoming stockholders of Holdco;

- Holdco would borrow up to $1 billion under a new term loan financing, or Holdco Credit Facility; and

Holdco would make a capital contribution to NRG in the amount of the $1 billion borrowed under the Holdco Credit Facility, less fees and expenses associated with the loan, which will be used to prepay NRG s existing Term B loan under its existing Senior Credit Facility.

In connection with the Comprehensive Capital Allocation Plan, on June 8, 2007, NRG completed the $4.4 billion refinancing of the Company s Senior Credit Facility previously announced on May 2, 2007. The transaction resulted in a 0.25% reduction on the spread that the Company pays on its Term B loan and Synthetic Letter of Credit facility, a $200 million reduction in the Synthetic Letter of Credit Facility to $1.3 billion, and various amendments to provide improved flexibility, efficiency for returning capital to shareholders, asset repowering and investment opportunities. The pricing on the Company s Term B loan and Synthetic Letter of Credit is also subject to further reductions upon the achievement of certain financial ratios. The refinancing resulted in a charge of approximately $35 million to the current period s results of operations which were primarily related to the write-off of previously deferred financing costs.

Other amendments to NRG s existing Senior Credit Facility include amendments that:

permit the completion of the Holdco structure;

permit the payment of up to $150 million in annual common stock dividends;

exclude principal and interest payments made on the Holdco Credit Facility, once funded, from being considered restricted payments under its senior credit facility;

modify the existing excess cash flow prepayment mechanism so that the prepayments are offered to both NRG and Holdco on a pro rata basis; and

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.

Also in connection with the Comprehensive Capital Allocation Plan, the Company executed the Holdco Credit Facility, which is a delayed-draw credit facility providing for the funding of $1 billion in term loan financing to Holdco. For this commitment, NRG will pay the participants a fee from June 8, 2007, until the earlier of the date the facility is drawn upon or the termination date of December 28, 2007. The fee is equal to 0.5% of the facility for the first 180 days and 0.75% thereafter. No balances were outstanding under this credit facility at June 30, 2007. The formation of the Holdco structure and the drawdown on the Holdco Credit Facility are contingent upon receiving the approval of three regulatory bodies, two of which have granted approval, with the final approval anticipated in the second half of 2007.

The Company previously announced its intention to form and fund the Holdco structure during the fourth quarter 2007. If this occurs, it will constitute a change in control event under the Company s Senior Note indentures. If the current weakness in the credit markets persists into the fourth quarter and NRG s Senior Notes trade at levels below par, the Company will likely postpone implementation of the Holdco structure or allow the Holdco credit facility to expire on December 28, 2007. If this occurs, the Company would likely delay the initiation of the planned common stock dividend.

**Note 8 Changes in Capital Structure**

***Stock Split***

On April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. In connection with the stock split, the Company transferred approximately $1.3 million from Additional Paid-in Capital to Common Stock, representing the par value of additional shares issued. All share amounts for all periods presented have been adjusted to reflect the stock split.

The following table reflects the changes in NRG s common stock issued and outstanding for the six months ended June 30, 2007 and 2006:

| | Authorized | Issued | Treasury | Outstanding |
|---|---|---|---|---|
| Balance as of December 31, 2006 | 500,000,000 | 274,248,264 | (29,601,162) | 244,647,102 |
| Capital Allocation Program Phase II during the first half of 2007 | | | (5,669,200) | (5,669,200) |
| Shares issued from LTIP through June 30, 2007 | | 851,885 | | 851,885 |
| Retirement of shares through June 30, 2007 | | (14,094,962) | 14,094,962 | |
| **Balance as of June 30, 2007** | 500,000,000 | 261,005,187 | (21,175,400) | 239,829,787 |
| Balance as of December 31, 2005 | 500,000,000 | 200,097,352 | (38,693,576) | 161,403,776 |
| Shares issued January 2006 | | 41,710,114 | | 41,710,114 |
| Acquisition of Texas Genco LLC | | 32,119,008 | 38,693,576 | 70,812,584 |
| Shares issued from LTIP through June 30, 2006 | | 31,690 | | 31,690 |
| **Balance as of June 30, 2006** | 500,000,000 | 273,958,164 | | 273,958,164 |

***Common Stock***

NRG s authorized common stock consists of 500 million shares of NRG stock. Common stock issued as of June 30, 2007 and 2006 was 261,005,187 and 273,958,164 shares, respectively.

***Treasury Stock***

In 2006, NRG initiated a Capital Allocation Program to be executed in two phases. Phase I was completed in the fourth quarter 2006, with the repurchase of 21,175,400 shares of the Company s common stock for approximately $500 million. Phase II is also a $500 million share buyback program that began in the fourth quarter 2006 with the repurchase of 8,425,762 shares of NRG common stock for a total of approximately $232 million. During the first half of 2007, NRG repurchased an additional 5,669,200 shares of the Company s common stock for approximately $215 million, of which 2,669,200 shares were repurchased during the three months ended June 30, 2007, for approximately $113 million. The Company expects to complete Phase II of its previously announced $1 billion share repurchase program by the end of the third quarter 2007, with the repurchase of approximately $53 million in NRG common stock.

As part of Phase I of the Capital Allocation Program, NRG, through its unrestricted wholly-owned subsidiaries NRG Common Stock Fund I, or CSF I, and NRG Common Stock Fund II, or CSF II, issued notes and preferred interests to Credit Suisse. These notes and preferred interests contain a feature considered an embedded derivative, which requires NRG to pay to Credit Suisse at maturity, either in cash or stock, the excess of NRG s then current stock price over a Reference Price. This Reference Price is the price of NRG s stock in excess of a compound annual growth rate of 20% beyond the volume-weighted average share price of the stock at the time of repurchase. As of June 30, 2007, the amount owed to Credit Suisse was approximately $97 million, with approximately $89 million relating to CSF I whose notes and preferred interests mature in 2008 and $8 million relating to CSF II whose notes and preferred interests mature in 2009.

***Retirement of Treasury Stock***

On May 22, 2007, on a pre-stock split basis, NRG retired 7,047,481 (14,094,962 on a post-stock split basis) shares of treasury stock. These retired shares are now included in the Company s pool of authorized but unissued shares. The retired stock had a carrying value of approximately $447 million. The Company s accounting policy upon the formal retirement of treasury stock is to deduct its par value from Common Stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital.

**Note 9 Equity Compensation**

NRG s compensation plans allow for anti dilutive adjustments for stock splits, and as such, all share and per share amounts within the tables below reflect the impact of a two-for-one stock split discussed in Note 8, *Changes in Capital Structure*:

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***Non-Qualified Stock Options, or NQSO s***

The following table summarizes the change in the Company s outstanding NQSO for the six months ended June 30, 2007:

| | Shares | Weighted Average Exercise Price | Weighted Average Grant-Date Fair Value Per Share |
|---|---|---|---|
| **Outstanding as of December 31, 2006** | 3,411,072 | $ 17.59 | $ 6.70 |
| Granted | 762,350 | 28.37 | 8.25 |
| Forfeited | (122,670) | 24.09 | 7.31 |
| Exercised | (251,847) | 15.65 | 5.82 |
| **Outstanding at June 30, 2007** | 3,798,905 | 19.67 | 7.05 |
| **Exercisable at June 30, 2007** | 1,958,606 | $ 13.93 | $ 6.43 |

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

The following table shows the change in the outstanding RSU balance during the six months ended June 30, 2007:

| Non-vested Shares | Shares | Weighted Average Grant-Date Fair Value Per Share |
|---|---|---|
| **Non-vested as of December 31, 2006** | 2,277,186 | $ 15.73 |
| Granted | 92,580 | 26.96 |
| Vested | (1,005,700) | 10.05 |
| Forfeited | (66,600) | 19.77 |
| **Outstanding as of June 30, 2007** | 1,297,466 | $ 20.73 |

***Performance Units, or PU s***

The following table shows the change in the outstanding PU balance during the six months ended June 30, 2007:

| Non-vested Shares | Shares | Weighted Average Grant-Date Fair Value Per Share |
|---|---|---|
| **Non-vested as of December 31, 2006** | 410,664 | $ 17.24 |
| Granted | 183,800 | 16.91 |
| Vested | | |
| Forfeited | (41,600) | 16.55 |
| **Outstanding as of June 30, 2007** | 552,864 | $ 17.19 |

**Note 10 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. Both basic and diluted earnings per share for all prior periods have been recast to reflect the impact of the Company s two-for-one stock split as discussed in Note 8, *Changes in Capital Structure*.

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **(In millions, except per share data)** | **2007** | **2006** | **2007** | **2006** |
| ***Basic earnings per share*** | | | | |
| **Numerator:** | | | | |
| Income from continuing operations | $ 149 | $ 202 | $ 214 | $ 217 |
| Preferred stock dividends | (14) | (14) | (28) | (25) |
| Net income available to common stockholders from continuing operations | 135 | 188 | 186 | 192 |
| Discontinued operations, net of income tax expense | | 1 | | 12 |
| Net income available to common stockholders | $ 135 | $ 189 | $ 186 | $ 204 |
| **Denominator:** | | | | |
| Weighted average number of common shares outstanding | 240.3 | 274.0 | 241.1 | 254.6 |
| ***Basic earnings per share:*** | | | | |
| Income from continuing operations | $ 0.56 | $ 0.69 | $ 0.77 | $ 0.75 |
| Discontinued operations, net of income tax expense | | | | 0.05 |
| Net income | $ 0.56 | $ 0.69 | $ 0.77 | $ 0.80 |
| ***Diluted earnings per share*** | | | | |
| **Numerator:** | | | | |
| Net income available to common stockholders from continuing operations | $ 135 | $ 188 | $ 186 | $ 192 |
| Add preferred stock dividends for dilutive preferred stock | 11 | 11 | 8 | 20 |
| Adjusted income from continuing operations | 146 | 199 | 194 | 212 |
| Discontinued operations, net of tax | | 1 | | 12 |
| Net income available to common stockholders | $ 146 | $ 200 | $ 194 | $ 224 |
| ***Denominator:*** | | | | |
| Weighted average number of common shares outstanding | 240.3 | 274.0 | 241.1 | 254.6 |
| Incremental shares attributable to the issuance of equity compensation (treasury stock method) | 3.7 | 3.0 | 3.5 | 2.8 |
| Incremental shares attributable to embedded derivatives of certain financial instruments (if-converted method) | 6.5 | | 7.4 | |
| Incremental shares attributable to assumed conversion features of outstanding preferred stock (if-converted | 37.5 | 41.6 | 21.0 | 37.8 |

| | | | | |
|---|---|---|---|---|
| method) | | | | |
| Total dilutive shares | 288.0 | 318.6 | 273.0 | 295.2 |
| ***Diluted earnings per share:*** | | | | |
| Income from continuing operations | $ 0.51 | $ 0.63 | $ 0.71 | $ 0.72 |
| Discontinued operations, net of tax | | | | 0.04 |
| Net income | $ 0.51 | $ 0.63 | $ 0.71 | $ 0.76 |

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

| | **Three months ended June 30** | | **Six months ended June 30** | |
|---|---|---|---|---|
| **(In millions)** | **2007** | **2006** | **2007** | **2006** |
| Equity compensation (NQSO s and PU s) | | 2.1 | 0.5 | 2.1 |
| 5.75% redeemable preferred stock | | | 16.5 | 3.6 |
| Embedded derivative of 3.625% convertible perpetual preferred stock | 11.8 | 16.0 | 11.2 | 16.0 |
| Embedded derivative of preferred interests and notes issued by CSF I and CSF II | 16.0 | | 15.7 | |
| Total | 27.8 | 18.1 | 43.9 | 21.7 |

**Note 11 Segment Reporting**

The Company s segment structure reflects NRG s core areas of operation which are primarily the geographic regions of the Company s wholesale power generation, the thermal and chilled water business, and corporate activities. Within NRG s wholesale power generation operations, there are distinct components with separate operating results and management structures for the following regions: Texas, Northeast, South Central, West and International. All prior period information have been recasted to reflect the change in the Company s segment structure as discussed in Note 17, *Segment Reporting*, to the Company s consolidated financial statements in its Annual Report on Form 10-K for the year ended December 31, 2006.

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| (In millions) Three months ended June 30, 2007 | Wholesale Power Generation Texas | Northeast | South Central | West | International | Thermal | Corporate | Elimination | Total |
|---|---|---|---|---|---|---|---|---|---|
| Operating revenues | $ 875 | $ 395 | $ 163 | $ 29 | $ 44 | $ 37 | $ 17 | $ (12) | $ 1,548 |
| Depreciation and amortization | 114 | 24 | 17 | 1 | | 3 | 2 | | 161 |
| Equity in earnings of unconsolidated affiliates | | | | (1) | 9 | | | | 8 |
| Income/(loss) from continuing operations before income taxes | 236 | 110 | (4) | 8 | 23 | 5 | (116) | (12) | 250 |
| **Net income/(loss)** | $ 134 | $ 110 | $ (4) | $ 8 | $ 17 | $ 5 | $ (109) | $ (12) | $ 149 |
| **Total assets** | $ 12,452 | $ 1,555 | $ 1,012 | $ 226 | $ 1,047 | $ 210 | $ 12,081 | $ (9,647) | $ 18,936 |

| (In millions) Three months ended June 30, 2006 | Wholesale Power Generation Texas | Northeast | South Central | West | International | Thermal | Corporate | Elimination | Total |
|---|---|---|---|---|---|---|---|---|---|
| Operating revenues | $ 941 | $ 303 | $ 125 | $ 49 | $ 45 | $ 34 | $ 3 | $ 2 | $ 1,502 |
| Depreciation and amortization | 131 | 22 | 18 | 1 | | 3 | 2 | | 177 |
| Equity in earnings of unconsolidated affiliates | | | | 1 | 7 | | | | 8 |
| Income/(loss) from continuing operations before income taxes | 292 | 51 | (14) | 9 | 21 | 3 | (75) | 2 | 289 |
| Income on discontinued operations, net of income taxes | | | | | (2) | | 3 | | 1 |
| **Net income/(loss)** | $ 256 | $ 50 | $ (14) | $ 8 | $ 15 | $ 3 | $ (117) | $ 2 | $ 203 |

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| (In millions)<br>Six months ended June 30, 2007 | Wholesale Power Generation<br>Texas | Northeast | South Central | West | International | Thermal | Corporate | Elimination | Total |
|---|---|---|---|---|---|---|---|---|---|
| Operating revenues | $ 1,570 | $ 737 | $ 314 | $ 57 | $ 87 | $ 86 | $ 22 | $ (15) | $ 2,858 |
| Depreciation and amortization | 228 | 49 | 34 | 1 | 1 | 6 | 3 | | 322 |
| Equity in earnings of unconsolidated affiliates | | | | (3) | 24 | | | | 21 |
| Income/(loss) from continuing operations before income taxes | 349 | 148 | 6 | 13 | 47 | 28 | (208) | (12) | 371 |
| **Net income/(loss)** | $ 194 | $ 148 | $ 6 | $ 13 | $ 34 | $ 28 | $ (197) | $ (12) | $ 214 |

| (In millions)<br>Six months ended June 30, 2006 | Wholesale Power Generation<br>Texas [(a)] | Northeast | South Central | West [(b)] | International | Thermal | Corporate | Elimination | Total |
|---|---|---|---|---|---|---|---|---|---|
| Operating revenues | $ 1,347 | $ 718 | $ 266 | $ 50 | $ 87 | $ 76 | $ 11 | $ (18) | $ 2,537 |
| Depreciation and amortization | 205 | 44 | 34 | 1 | 1 | 6 | 4 | | 295 |
| Equity in earnings of unconsolidated affiliates | | | | (1) | 28 | | 2 | | 29 |
| Income/(loss) from continuing operations before income taxes | 285 | 183 | 14 | 5 | 52 | 7 | (225) | (18) | 303 |
| Income/(loss) from discontinued operations, net of income taxes | | | | | (1) | | 13 | | 12 |
| **Net income/(loss)** | $ 274 | $ 182 | $ 14 | $ 6 | $ 38 | $ 7 | $ (274) | $ (18) | $ 229 |

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

*(b) Only included the equity earnings of WCP for the first quarter 2006.*

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**Note 12 Income Taxes**

Income tax expense for the three and six months ended June 30, 2007 was $101 million and $157 million, respectively, compared to income tax expense of $87 million and $86 million for the three and six months ended June 30, 2006, respectively. The income tax expense for the three and six months ended June 30, 2007 includes domestic tax expense of $95 million and $143 million, respectively, and foreign tax expense of $6 million and $14 million, respectively. The income tax expense for the three and six months ended June 30, 2006 includes domestic tax expense of $84 million and $73 million, respectively, and foreign tax expense of $3 million and $13 million, respectively.

A reconciliation of the U.S. statutory rate to NRG s effective tax rate from continuing operations for the six months ended June 30, 2007 and 2006 is as follows:

| | Six months ended June 30 | |
|---|---|---|
| **(In millions except rate data)** | **2007** | **2006** |
| Income from continuing operations before income taxes | $ 371 | $ 303 |
| Tax at 35% | 130 | 106 |
| State taxes | 16 | 16 |
| Valuation allowance | 2 | 3 |
| Disputed claims reserve | (1) | (29) |
| Foreign operations | (4) | (14) |
| Foreign dividends | 8 | |
| Non-deductible interest | 5 | |
| Permanent differences including subpart F income | 1 | 4 |
| Income tax expense | $ 157 | $ 86 |
| Effective income tax rate | 42.3% | 28.4% |

The effective income tax rate for the six months ended June 30, 2007 differs from the U.S. statutory rate of 35% due to a taxable dividend from foreign operations and non-deductible interest, offset by earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate. For the six months ended June 30, 2006, the effective tax rate differs from the U.S. statutory rate of 35% due to settlements paid from a claimant reserve established at bankruptcy as well as 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* As of June 30, 2007, NRG recorded a net deferred tax liability of $38 million. However, due to an assessment of positive and negative evidence, related to 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 $584 million of tax assets, thus a valuation allowance has remained, resulting in a net deferred tax liability of $622 million.

*NOL carryforwards* As of June 30, 2007, the Company had net operating loss, or NOL, carryforwards available for domestic income tax purposes of $90 million that will expire through 2027. In addition, NRG has cumulative foreign NOL carryforwards of $277 million of which $75 million will expire in 2016 and of which $202 million does not have an expiration date.

***Uncertain tax benefits***

NRG has identified certain unrecognized tax benefits whose after-tax value was $712 million, and if recognized, $19 million will impact the Company s effective tax rate. Of the $712 million in unrecognized tax benefits, $693 million relates to periods prior to the Company s emergence from bankruptcy, and in accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*, and the application of

Fresh Start accounting, any recognized benefit would not impact the Company s effective tax rate but would increase Additional Paid In Capital. NRG has accrued interest and penalty related to these unrecognized tax benefits of approximately $4 million as of the adoption of FIN 48 by the Company on January 1, 2007. An immaterial amount of interest and penalties related to unrecognized tax benefits was recognized in the Company s results of operations for the three and six months ended June 30, 2007.

*Tax jurisdictions* NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including major operations located in Germany, Australia, and Brazil. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2002. With few exceptions, state and local income tax examinations are no longer open for years before 2003. The Company s significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2000.

***German Tax Reform Act 2008***

On July 6, 2007, the German upper house of parliament passed Tax Reform Act 2008, which reduces the effective tax rates on earnings from approximately 36% to approximately 27%. As of June 30, 2007, NRG had a net deferred tax liability of approximately $109 million that will be impacted by this tax rate change during the third quarter 2007.

**Note 13 Benefit Plans and Other Postretirement Benefits**

The net annual periodic pension cost for the three and six months ended June 30, 2007 and 2006 related to all of the Company s defined benefit pension plans, include the following components:

| | Defined Benefit Pension Plans | | | |
|---|---|---|---|---|
| | Three months ended June 30, | | Six months ended June 30, | |
| **(In millions)** | **2007** | **2006** | **2007** | **2006** |
| Service cost benefits earned | $ 4 | $ 5 | $ 8 | $ 9 |
| Interest cost on benefit obligation | 5 | 5 | 9 | 8 |
| Expected return on plan assets | (3) | (2) | (6) | (3) |
| Net periodic benefit cost | $ 6 | $ 8 | $ 11 | $ 14 |

The net annual periodic cost for the three and six months ended June 30, 2007 and 2006 related to all of the Company s other post retirement benefits plans, include the following components:

| | Other Postretirement Benefits Plans | | | |
|---|---|---|---|---|
| | Three months ended June 30, | | Six months ended June 30, | |
| **(In millions)** | **2007** | **2006** | **2007** | **2006** |
| Service cost benefits earned | $ | $ | $ 1 | $ 1 |
| Interest cost on benefit obligation | 1 | 1 | 2 | 2 |
| Net periodic benefit cost | $ 1 | $ 1 | $ 3 | $ 3 |

The total amount of employer contributions paid for the six months ended June 30, 2007 was $35 million.

**Note 14 Commitments and Contingencies**

**Commitments**

***Second Lien Structure***

NRG has granted second priority liens to certain counterparties on substantially all of the Company s assets in the United States in order to secure certain obligations, which are primarily long-term in nature under certain power sale agreements and related contracts. NRG uses the second lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under these agreements. Within the second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties. As of June 30, 2007, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the second lien structure was approximately $65 million.

***Fuel Commitments***

NRG enters into long-term contractual arrangements to procure fuel and transportation services for the Company s generation assets. NRG entered into additional coal and gas purchase agreements during the first half of 2007 with total commitments of approximately $454 million and $713 million, respectively, spanning over the next three to ten years. Approximately $326 million of the coal commitments were entered into in order to ensure adequate future supplies at the Company s Limestone facility because the Company has not yet received an agreement for supply of coal from the mine located at the Limestone facility beyond 2007.

***RepoweringNRG Project Deposits***

NRG has made non-refundable deposits totaling approximately $15 million towards the procurement of equipment related to *RepoweringNRG* initiatives. The Company believes that these deposits are necessary for the timely and successful execution of these projects. Although NRG is committed to their successful implementation, the Company may decide not to take delivery of the equipment and thus terminate the projects. This would result in the Company expensing the deposit it already has made.

**Contingencies**

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 effect 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. The consolidated cases moved between state and federal court several times. 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 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 and on February 26, 2007, the court affirmed the lower court s judgment of dismissal. Plaintiffs voluntarily dismissed the case with prejudice on May 1, 2007. These same claims were previously dismissed on May 17, 2006, by the U.S. Bankruptcy Court in New York and plaintiffs did not appeal. 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.

In August 2006, Dynegy executed a settlement agreement to resolve the class action claims in the natural gas anti-trust cases consolidated and pending in state court in San Diego, California. Approved in late December 2006, the Court has dismissed the class action claims. WCP and some of its subsidiaries were named defendants and Dynegy s settlement includes 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 trades. The settlement 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.

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. In May 2007, the Court preliminary approved and Dynegy funded the settlement. Neither WCP, its 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.

***California Department of Water Resources***

On December 19, 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the Federal Energy Regulatory Commission s, or FERC s, prior determinations regarding the enforceability of certain wholesale power contracts and remanded the case to FERC for further proceedings consistent with the decision. One of these contracts was the wholesale power contract between the California Department of Water Resources, or CDWR, and subsidiaries of WCP. This case originated with a February 2002 complaint filed at FERC by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, FERC rejected this complaint, denied rehearing, and the case was appealed to the Ninth Circuit where oral argument was held on December 8, 2004. On December 19, 2006, the Court decided that in FERC s review of the contracts at issue, FERC could not rely on the Mobile-Sierra standard presumption of just and reasonable rates, where such contracts were not reviewed by FERC with full knowledge of the then existing market conditions. WCP and the other defendants separately filed petitions for certiorari seeking review by the U.S. Supreme Court on May 3, 2007. The Supreme Court will decide in the fourth quarter 2007 whether it will accept the appeal. At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG s financial position, statement of operations, and statement of cash flows. As part of the 2006 acquisition of Dynegy s 50% ownership interest in WCP, WCP and NRG assumed responsibility for any risk of loss arising from this case, unless any such loss was deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally between WCP and Dynegy.

***Connecticut Congestion Charges***

On November 28, 2001, Connecticut Light & Power, or 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 NRG Power Marketing, Inc., or PMI, under contract and PMI counterclaimed. CL&P s motion for summary judgment was granted by the Court on July 20, 2007. PMI has 30 days from the date of the decision to decide to file an appeal. The full amount withheld by CL&P was previously reserved as a reduction to outstanding accounts receivable and no payment will be required as a result of the decision.

***Station Service Disputes***

On October 2, 2000, Niagara Mohawk Power Corporation, or 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 the disputes in the 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. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on June 23, 2006, denied the appeal finding that New York Independent System Operator s, or 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. On April 30, 2007, the U.S. Supreme Court denied NiMo s request for review of the D.C. Circuit decision thus ending further avenues to appeal FERC s ruling in this matter. 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. Briefing before the three member arbitration panel is ongoing and a hearing is set for September 2007. NRG believes it is adequately reserved.

***Itiquira Energetica S.A.***

NRG s Brazilian project company, Itiquira Energetica S.A, or ITISA, the owner of a 155 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 ITISA in September 2002 and pertains to certain matters arising under the EPC contract between the parties. ITISA sought Real 140 million and asserted that Inepar breached the contract. Inepar sought Real 39 million and alleged that ITISA breached the contract. On September 2, 2005, the arbitration panel ruled in favor of ITISA, 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, ITISA s award was increased to approximately Real 227 million (approximately $118 million as of June 30, 2007). On December 21, 2005, Inepar s request for clarifications was denied. ITISA has commenced the lengthy process in Brazil to execute on the arbitral award. NRG is unable to predict the outcome of this execution process. Due to the uncertainty of the ongoing collection process, NRG is accounting for receipt of any amounts as a gain contingency.

***Lignite Contract with Texas Westmoreland Coal Co.***

The lignite used to fuel the Texas region s Limestone facility is obtained from a surface mine adjacent to the facility under an amended long-term contract with Texas Westmoreland Coal Co., or TWCC, entered into in August 1999. In June 2007, TWCC notified NRG of their election to deliver zero tons of lignite from the Jewett Mine for 2008, effectively ending TWCC s rights to deliver lignite from the Jewett Mine per the long-term contract after December 31, 2007. NRG is currently seeking to negotiate an agreement with TWCC that will result in a new contractual structure for the mine, as well as an extension of mining through 2018. However, the Company cannot predict whether or not it will be able to reach an acceptable agreement with TWCC. If no agreement is reached, production from the mine could cease as early as January 2008. If no agreement is reached the Company expects to have adequate supply of PRB coal and adequate rail transport to continue operations of the Limestone Facility.

TWCC is responsible for performing ongoing reclamation activities at the mine until all lignite reserves have been produced. When production is completed at the mine, NRG will be responsible for final mine reclamation obligations. Final reclamation activity was previously expected to commence in 2015, and based on the assumption that mining would continue through the term of the long-term contract into August 2015. As of June 30, 2007, NRG has established an asset retirement obligation for mine reclamation costs of $21 million. However, should NRG be unsuccessful in its negotiations to enter into a new agreement, cash payments for reclamation costs would be incurred as early as 2008. Management is currently assessing the potential impact on our results of operation, financial position and cash flows from such early reclamation. In addition, up to $86 million of mining assets may be subject to impairment.

The Railroad Commission of Texas has imposed a bond obligation of approximately $70 million on TWCC for the reclamation of this lignite mine. Pursuant to the contract with TWCC, an affiliate of CenterPoint Energy, Inc. has guaranteed $50 million of this obligation until 2010. The remaining sum of approximately $20 million has been bonded by the mine operator, TWCC. Under the terms of the agreement, NRG is required to post a corporate guarantee of TWCC s bond obligation in the amount of $50 million when CenterPoint s obligation lapses.

***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

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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 bankruptcy plan, totaling $25 million in cash and 5,082,000 shares of common stock. As of July 18, 2007, the reserve held approximately $10 million in cash and approximately 1,319,142 shares of common stock on a post-stock split basis. NRG believes the cash and stock together represent sufficient funds to satisfy all remaining disputed claims.

**Note 15 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, *Accounting for the Effects of Certain Types of Regulation*, 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 levels and in the regions in which NRG operates.

***Northeast Region***

*New England* On July 16, 2007, FERC conditionally accepted, subject to refund, the Reliability-Must-Run, or RMR, agreement filed on April 26, 2007 by Norwalk Power for its units 1 and 2, specifying a June 19, 2007 effective date. Norwalk s RMR rate and its eligibility for the RMR agreement, determined based upon the facility s projected market revenues and costs are subject to further proceedings. Norwalk filed for the RMR agreement in response to FERC s order eliminating the Peaking Unit Safe Harbor bidding mechanism which took effect on June 19, 2007.

On December 28, 2006, the Attorney Generals of the State of Connecticut and Commonwealth of Massachusetts filed an appeal of the FERC orders accepting the settlement of the New England capacity market design with the U.S. Court of Appeals for the D.C. Circuit. The settlement, filed March 7, 2006, by a broad group of New England market participants, 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. On June 16, 2006, FERC issued an order accepting the settlement, which was reaffirmed on rehearing by order dated October 31, 2006. Interim capacity transition payments provided for under the FCM settlement commenced December 1, 2006, as scheduled. A successful appeal by the Attorneys General could disturb the settlement and create a refund obligation of interim capacity transition payments. On April 5, 2007, the Connecticut Attorney General filed a motion seeking to stay the interim capacity transition payments, which was rejected on May 17, 2007.

*New York* On March 6, 2007, FERC rejected the NYISO s proposed tariff revisions that would have imposed additional market power mitigation on the current owners of Consolidated Edison s divested generation units in New York City, including NRG s Arthur Kill and Astoria facilities. The proposed mitigation would have effectively lowered the capacity offer cap for those units from $105/kW-year to $82/kW-year. Although the specific proposal was rejected, FERC initiated an investigation to determine the justness and reasonableness of the NYISO s in-city installed capacity, or ICAP, market, setting a refund effective date of May 12, 2007. On July 6, 2007, FERC issued an order establishing an approximately six-month paper hearing process to address reforms to the in-city ICAP market and to formulate comprehensive solutions. FERC also initiated an enforcement investigation into the in-city market.

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. Resettlement of the market, while viewed as unlikely, could have a material financial impact on the Company s results of operations.

***West Region***

In November 2006, NRG was awarded a 260 MW power purchase agreement, or PPA, by Southern California Edison, or SCE, to repower Units 1-4 at the Company s Long Beach Generating Station in Long Beach, California. On January 25, 2007, the California Public Utilities Commission, or CPUC, issued its order approving the PPA, and authorizing cost recovery by SCE, which order was reaffirmed on rehearing on April 12, 2007. The Utility Reform Network, a consumer advocacy group, has appealed the CPUC orders seeking to overturn the CPUC approval of the PPA and effectively void the PPA. Although the CPUC approval of the PPA is not final, NRG is proceeding with the project. NRG has entered into a waiver agreement with SCE to refund certain payments under the PPA if full cost recovery is not affirmed on appeal.

On December 1, 2006, NRG filed to extend the existing RMR agreements for NRG s Cabrillo Power I, LLC (Encina) and Cabrillo Power II, LLC (San Diego Jets) for 2007, seeking to continue the then-existing rate effective January 1, 2007. On January 24, 2007, FERC accepted the Cabrillo Power I filing. On January 30, 2007, FERC accepted the Cabrillo II filing, subject to refund, in response to protests filed by the CPUC and CAISO, and established settlement procedures. The parties have reached a settlement in principle that will result in an annual fixed revenue requirement of approximately $5 million, which has been accepted by FERC.

**Note 16 Environmental Matters**

The construction and operation of power projects are subject to stringent environmental and 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 modifications to further reduce potential environmental impacts. In addition, increased public concern and mounting political pressure may result in federal or additional state requirements to reduce or mitigate the effects of greenhouse gas emissions, including carbon dioxide. In general, the effect of such future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions or additional costs on the Company s operations.

***Environmental Capital Expenditures***

Based on current rules, technology and plans, NRG has estimated that capital expenditures to be incurred from 2007 through 2012 to keep NRG s facilities in compliance with environmental laws will be between $1.0 billion and $1.5 billion. The environmental capital expenditures, in general, are related to installation of particulate, $SO_2$, $NO_x$, and mercury controls to comply with Clean Air Interstate Rule, the Clean Air Mercury Rule and related state requirements as well as installation of Best Technology Available under the Phase II 316(b) Rule. The new estimate has been revised from an earlier estimate of $1.3 billion. The increase is primarily driven by the Indian River Plant s program for compliance with Delaware s Regulation No. 1146, which is further discussed below. The final rules as promulgated at the end of 2006 were different than had been expected and, in particular, had substituted strict unit-by-unit emissions standards for the facility-wide standards. A thorough engineering analysis was conducted in respect of these differences and has concluded that additional controls are required to ensure compliance with the final rule. This was compounded by a slight increase in market costs for advanced controls. The range of capital expenditure costs is largely a function of the various options under consideration by the Company to address the impact of Regulation No. 1146 on Indian River, which include the mothballing of one or more units, the installation of interim controls and the construction of full back-end controls.

***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 a 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 (without fault) and joint and several liability. The cost of investigation, remediation, or removal of any hazardous or toxic substances or petroleum products could be substantial.

***Northeast Region***

In January 2006, NRG Indian River Operations, Inc. received a letter of informal notification from DNREC, stating that it may be a potentially responsible party with respect to a historic captive landfill. NRG entered into a voluntary clean-up program agreement in

July 2007 to investigate the site. The Company is unable to predict the financial impact until the results of the investigation are available.

In November 2006, DNREC promulgated 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 govern the control of $SO_2$, $NO_x$, and mercury emissions from electric generating units. NRG s current plan to install controls at the Company s Indian River facility, while on an accelerated basis, is unable to meet certain deadlines for $SO_2$ and $NO_x$ controls in Phase 1, taking into account the time required, as a practical matter, to design, install, and commission the necessary equipment. NRG and the owners of all other subject facilities in the state filed a challenge to Reg 1146 with the Environmental Appeals Board, or EAB, on December 6, 2006. In addition, NRG also filed a protective appeal with the Delaware Superior Court on December 29, 2006. Discussions with DNREC are ongoing and a hearing is scheduled to commence before the EAB on August 27, 2007. NRG is unable to predict the outcome of the proceedings at this time, but failure to obtain relief could result in a material impact on the Company s results of operations.

***South Central Region***

On January 27, 2004, NRG s Louisiana Generating, LLC and the Company s Big Cajun II plant received a request under Section 114 of the Clean Air Act from the United States Environmental Protection Agency, or USEPA, seeking information primarily related to physical changes made at the Big Cajun II plant, and subsequently received a notice of violation, or NOV, on February 15, 2005, alleging that NRG s predecessors had undertaken projects that triggered requirements under the Prevention of Significant Deterioration program, including the installation of emission controls. NRG submitted multiple responses commencing February 27, 2004 and ending on 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 NRG s Louisiana Generating, LLC offices by the DOJ during the week of August 14, 2006. On December 8, 2006, the USEPA issued a supplemental NOV updating the original February 15, 2005 NOV. Discussions with the USEPA are ongoing and the Company cannot predict with certainty the outcome of this matter.

**Note 17 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 purchases and sale agreements, commodity sale and purchase agreements, joint venture agreements, operation 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 some cases, NRG s maximum potential liability cannot be estimated, since the underlying agreements contain no limits on potential liability.

This footnote should be read in conjunction with the complete description under Note 25, *Guarantees*, to the Company s financial statements in its Annual Report on Form 10-K for the year ended December 31, 2006.

For the six months ended June 30, 2007, NRG had net increases to its guarantee obligations under other commercial arrangements of approximately $148 million. These increases pertained to payment obligations of PMI.

**Note 18 Condensed Consolidating Financial Information**

As of June 30, 2007, the Company had $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016 and $1.1 billion of 7.375% Senior Notes due 2017 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 June 30, 2007:

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
Hoffman Summit Wind Project, LLC
Huntley IGCC LLC
Huntley Power LLC
Indian River IGCC LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Lake Erie Properties Inc.
Louisiana Generating LLC
Middletown Power LLC
Montville IGCC LLC
Montville Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP, 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 Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Connecticut Affiliate Services Inc
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Generation Holdings, Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
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 Texas LLC
NRG Texas Power LLC
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Padoma Wind Power, LLC
Saguaro Power LLC
San Juan Mesa Wind Project II, 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 SEC s Regulation S-X. The financial

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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.

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Statements of Operations**
**For the Three Months Ended June 30, 2007**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[(a)] | Consolidated Balance |
|---|---|---|---|---|---|
| **Operating Revenues** | | | | | |
| Total operating revenues | $ 1,459 | $ 89 | $ | $ | $ 1,548 |
| **Operating Costs and Expenses** | | | | | |
| Cost of operations | 786 | 56 | 1 | | 843 |
| Depreciation and amortization | 154 | 7 | | | 161 |
| General and administrative | 21 | 4 | 46 | | 71 |
| Development costs | 32 | | 4 | | 36 |
| Total operating costs and expenses | 993 | 67 | 51 | | 1,111 |
| Loss on sale of assets | (1) | | | | (1) |
| **Operating Income/(Loss)** | 465 | 22 | (51) | | 436 |
| **Other Income/(Expense)** | | | | | |
| Equity in earnings of consolidated subsidiaries | 22 | | 253 | (275) | |
| Equity in earnings/(losses) of unconsolidated affiliates | (1) | 9 | | | 8 |
| Write downs and gains on sale of equity method investments | | 1 | | | 1 |
| Other income, net | 3 | 9 | 7 | (5) | 14 |
| Refinancing expense | | | (35) | | (35) |
| Interest expense | (68) | (22) | (89) | 5 | (174) |
| Total other income/(expense) | (44) | (3) | 136 | (275) | (186) |
| **Income From Continuing Operations Before Income Taxes** | 421 | 19 | 85 | (275) | 250 |
| Income tax expense/(benefit) | 157 | 8 | (64) | | 101 |
| **Net Income** | $ 264 | $ 11 | $ 149 | $ (275) | $ 149 |

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

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Statements of Operations**
**For the Six Months Ended June 30, 2007**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[(a)] | Consolidated Balance |
|---|---|---|---|---|---|
| **Operating Revenues** | | | | | |
| Total operating revenues | $ 2,674 | $ 184 | $ | $ | $ 2,858 |
| **Operating Costs and Expenses** | | | | | |
| Cost of operations | 1,502 | 122 | 3 | | 1,627 |
| Depreciation and amortization | 307 | 14 | 1 | | 322 |
| General and administrative | 49 | 7 | 101 | | 157 |
| Development costs | 55 | | 4 | | 59 |
| Total operating costs and expenses | 1,913 | 143 | 109 | | 2,165 |
| Gain/(loss) on sale of assets | 17 | | (1) | | 16 |
| **Operating Income/(Loss)** | 778 | 41 | (110) | | 709 |
| **Other Income/(Expense)** | | | | | |
| Equity in earnings of consolidated subsidiaries | 54 | | 409 | (463) | |
| Equity in earnings/(losses) of unconsolidated affiliates | (3) | 24 | | | 21 |
| Write downs and gains on sale of equity method investments | | 1 | | | 1 |
| Other income, net | 5 | 18 | 17 | (10) | 30 |
| Refinancing expense | | | (35) | | (35) |
| Interest expense | (138) | (48) | (179) | 10 | (355) |
| Total other income/(expense) | (82) | (5) | 212 | (463) | (338) |
| **Income From Continuing Operations Before Income Taxes** | 696 | 36 | 102 | (463) | 371 |
| Income tax expense/(benefit) | 256 | 13 | (112) | | 157 |
| **Net Income** | $ 440 | $ 23 | $ 214 | $ (463) | $ 214 |

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

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Balance Sheet**
**June 30, 2007**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[a] | Consolidated Balance |
|---|---|---|---|---|---|
| **ASSETS** | | | | | |
| **Current Assets** | | | | | |
| Cash and cash equivalents | $ | $ 167 | $ 680 | $ | $ 847 |
| Accounts receivable, net | 526 | 46 | 32 | (40) | 564 |
| Inventory | 417 | 13 | | | 430 |
| Derivative instruments valuation | 809 | | 1 | | 810 |
| Deferred income taxes | 86 | | (24) | | 62 |
| Prepayments and other current assets | 153 | 32 | 242 | (143) | 284 |
| Total current assets | 1,991 | 258 | 931 | (183) | 2,997 |
| **Net property, plant and equipment** | 11,036 | 398 | 20 | | 11,454 |
| **Other Assets** | | | | | |
| Investment in subsidiaries | 513 | | 9,321 | (9,834) | |
| Equity investments in affiliates | 28 | 343 | | | 371 |
| Notes receivable and capital lease | 1,049 | 474 | 5,185 | (6,234) | 474 |
| Goodwill | 1,785 | | | | 1,785 |
| Intangible assets, net | 931 | | | | 931 |
| Nuclear decommissioning trust | 377 | | | | 377 |
| Derivative instruments valuation | 171 | | 32 | | 203 |
| Deferred income taxes | | 150 | (121) | | 29 |
| Other non-current assets | 11 | 57 | 142 | | 210 |
| Intangible assets held-for-sale | 105 | | | | 105 |
| Total other assets | 4,970 | 1,024 | 14,559 | (16,068) | 4,485 |
| **Total Assets** | $ 17,997 | $ 1,680 | $ 15,510 | $ (16,251) | $ 18,936 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | | | | |
| **Current Liabilities** | | | | | |
| Current portion of long-term debt | $ 41 | $ 94 | $ 31 | $ (40) | $ 126 |
| Accounts Payable | (519) | 98 | 804 | | 383 |
| Derivative instruments valuation | 687 | | | | 687 |
| Accrued expenses and other current liabilities | 265 | 94 | 233 | (143) | 449 |

| | | | | | |
|---|---|---|---|---|---|
| Total current liabilities | 474 | 286 | 1,068 | (183) | 1,645 |
| **Other Liabilities** | | | | | |
| Long-term debt | 5,164 | 823 | 8,856 | (6,234) | 8,609 |
| Nuclear decommissioning reserve | 298 | | | | 298 |
| Nuclear decommissioning trust liability | 335 | | | | 335 |
| Deferred income taxes | 586 | 174 | (47) | | 713 |
| Derivative instruments valuation | 536 | (2) | 28 | | 562 |
| Out-of-market contracts | 768 | | | | 768 |
| Other long-term obligations | 373 | 27 | 25 | | 425 |
| Total non-current liabilities | 8,060 | 1,022 | 8,862 | (6,234) | 11,710 |
| **Total liabilities** | 8,534 | 1,308 | 9,930 | (6,417) | 13,355 |
| Minority interest | | 1 | | | 1 |
| 3.625% Preferred Stock | | | 247 | | 247 |
| **Stockholders Equity** | 9,463 | 371 | 5,333 | (9,834) | 5,333 |
| **Total Liabilities and Stockholders Equity** | $ 17,997 | $ 1,680 | $ 15,510 | $ (16,251) | $ 18,936 |

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

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Statements of Cash Flows**
**For the Six Months Ended June 30, 2007**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[a] | Consolidated Balance |
|---|---|---|---|---|---|
| **Cash Flows from Operating Activities** | | | | | |
| Net income | $ 440 | $ 23 | $ 214 | $ (463) | $ 214 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | | | |
| Distributions less than equity earnings of unconsolidated affiliates and consolidated subsidiaries | 251 | (10) | (107) | (141) | (7) |
| Depreciation and amortization of nuclear fuel | 333 | 14 | 1 | | 348 |
| Amortization of financing costs and debt discount | | 3 | 48 | | 51 |
| Amortization of intangibles and out-of-market contracts | (73) | | | | (73) |
| Amortization of unearned equity compensation | | | 14 | | 14 |
| Changes in deferred income taxes | 35 | 169 | (62) | | 142 |
| Changes in nuclear decommissioning liability | 20 | | | | 20 |
| Changes in derivatives | 66 | 4 | (23) | | 47 |
| Gain on sale of assets | (16) | | | | (16) |
| Gain on sale of emission allowances | (24) | | | | (24) |
| Changes in collateral deposits supporting energy risk management activities | (103) | | | | (103) |
| Write down and gains on sale of equity method investments | | (1) | | | (1) |
| Cash provided by/(used by) changes in other working capital, net of dispositions affects | (139) | (163) | 149 | | (153) |
| **Net Cash Provided by Operating Activities** | 790 | 39 | 234 | (604) | 459 |
| **Cash Flows from Investing Activities** | | | | | |
| Intercompany loans to subsidiaries | | | 361 | (361) | |
| Capital expenditures | (201) | (2) | (2) | | (205) |

| | | | | | |
|---|---|---|---|---|---|
| Increase in restricted cash | | (8) | | | (8) |
| Decrease in notes receivable | | 17 | | | 17 |
| Purchases of emission allowances | (135) | | | | (135) |
| Proceeds from sale of emission allowances | 131 | | | | 131 |
| Proceeds from sale of investments | | 2 | | | 2 |
| Proceeds from sale of assets | 29 | | | | 29 |
| Investments in marketable securities | | | 4 | | 4 |
| Decrease in trust fund balances | 13 | | | | 13 |
| Investments in trust fund securities | (140) | | | | (140) |
| Proceeds from sales of trust fund securities | 120 | | | | 120 |
| **Net Cash Provided/Used by Investing Activities** | (183) | 9 | 363 | (361) | (172) |
| **Cash Flows from Financing Activities** | | | | | |
| Payments to Parent for intercompany loans | (325) | (36) | | 361 | |
| Payments from intercompany dividends | (302) | (302) | | 604 | |
| Payments for dividends to preferred stockholders | | | (28) | | (28) |
| Payments for treasury stock | | | (215) | | (215) |
| Proceeds from issuance of long-term debt | | | 1,411 | | 1,411 |
| Payments for short and long-term debt | (1) | (30) | (1,428) | | (1,459) |
| **Net Cash Used by Financing Activities** | (628) | (368) | (260) | 965 | (291) |
| Effect of Exchange Rate Changes on Cash and Cash Equivalents | | 4 | | | 4 |
| **Net Increase/(Decrease) in Cash and Cash Equivalent** | (21) | (316) | 337 | | |
| **Cash and Cash Equivalents at Beginning of Period** | 20 | 432 | 343 | | 795 |
| **Cash and Cash Equivalents at End of Period** | $ (1) | $ 116 | $ 680 | $ | $ 795 |

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

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Statements of Operations**
**For the Three Months Ended June 30, 2006**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[a] | Consolidated Balance |
|---|---|---|---|---|---|
| **Operating Revenues** | | | | | |
| Total operating revenues | $ 1,423 | $ 79 | $ | $ | $ 1,502 |
| **Operating Costs and Expenses** | | | | | |
| Cost of operations | 776 | 54 | 2 | | 832 |
| Depreciation and amortization | 169 | 6 | 2 | | 177 |
| General and administrative | 23 | 5 | 55 | | 83 |
| Total operating costs and expenses | 968 | 65 | 59 | | 1,092 |
| **Operating Income/(Loss)** | 455 | 14 | (59) | | 410 |
| **Other Income/(Expense)** | | | | | |
| Equity in earnings of consolidated subsidiaries | 14 | | 270 | (284) | |
| Equity in earnings of unconsolidated affiliates | 1 | 7 | | | 8 |
| Write downs and gain on sales of equity method investments | | 14 | | | 14 |
| Other income, net | 23 | 7 | (17) | (5) | 8 |
| Interest expense | (82) | (16) | (58) | 5 | (151) |
| Total other income/(expense) | (44) | 12 | 195 | (284) | (121) |
| **Income From Continuing Operations Before Income Taxes** | 411 | 26 | 136 | (284) | 289 |
| Income tax expense/(benefit) | 154 | (1) | (66) | | 87 |
| **Income From Continuing Operations** | 257 | 27 | 202 | (284) | 202 |
| Income from discontinued operations, net of income tax expense | | | 1 | | 1 |
| **Net Income** | $ 257 | $ 27 | $ 203 | $ (284) | $ 203 |

*(a) All significant intercompany*

*transactions have been eliminated in consolidation.*

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Statements of Operations**
**For the Six Months Ended June 30, 2006**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[(a)] | Consolidated Balance |
|---|---|---|---|---|---|
| **Operating Revenues** | | | | | |
| Total operating revenues | $ 2,372 | $ 165 | $ | $ | $ 2,537 |
| **Operating Costs and Expenses** | | | | | |
| Cost of operations | 1,363 | 115 | 4 | | 1,482 |
| Depreciation and amortization | 280 | 12 | 3 | | 295 |
| General and administrative | 46 | 5 | 90 | | 141 |
| Total operating costs and expenses | 1,689 | 132 | 97 | | 1,918 |
| **Operating Income/(Loss)** | 683 | 33 | (97) | | 619 |
| **Other Income/(Expense)** | | | | | |
| Equity in earnings of consolidated subsidiaries | 36 | | 431 | (467) | |
| Equity in earnings of unconsolidated affiliates | 1 | 28 | | | 29 |
| Write downs and gain on sales of equity method investments | (3) | 14 | | | 11 |
| Other income, net | 26 | 82 | (10) | (10) | 88 |
| Refinancing expense | | | (178) | | (178) |
| Interest expense | (136) | (32) | (108) | 10 | (266) |
| Total other income/(expense) | (76) | 92 | 135 | (467) | (316) |
| **Income From Continuing Operations Before Income Taxes** | 607 | 125 | 38 | (467) | 303 |
| Income tax expense/(benefit) | 239 | 34 | (187) | | 86 |
| **Income From Continuing Operations** | 368 | 91 | 225 | (467) | 217 |
| Income from discontinued operations, net of income tax expense | | 8 | 4 | | 12 |
| **Net Income** | $ 368 | $ 99 | $ 229 | $ (467) | $ 229 |

*(a)*

*All significant intercompany transactions have been eliminated in consolidation.*

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Balance Sheet**
**December 31, 2006**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[(a)] | Consolidated Balance |
|---|---|---|---|---|---|
| **ASSETS** | | | | | |
| **Current Assets** | | | | | |
| Cash and cash equivalents | $ 20 | $ 432 | $ 343 | $ | $ 795 |
| Restricted cash | 1 | 43 | | | 44 |
| Accounts receivable-trade, net | 332 | 40 | | | 372 |
| Inventory | 408 | 13 | | | 421 |
| Derivative instruments valuation | 1,230 | | | | 1,230 |
| Prepayments and other current assets | 200 | 32 | 736 | (747) | 221 |
| Total current assets | 2,191 | 560 | 1,079 | (747) | 3,083 |
| **Net property, plant and equipment** | 11,178 | 403 | 19 | | 11,600 |
| **Other Assets** | | | | | |
| Investment in subsidiaries | 730 | | 9,163 | (9,893) | |
| Equity investments in affiliates | 31 | 313 | | | 344 |
| Notes receivable and capital lease | 1,015 | 479 | 5,503 | (6,518) | 479 |
| Goodwill | 1,789 | | | | 1,789 |
| Intangible assets, net | 977 | 4 | | | 981 |
| Nuclear decommissioning trust fund | 352 | | | | 352 |
| Derivative instruments valuation | 424 | | 15 | | 439 |
| Deferred income taxes | 27 | | | | 27 |
| Other non-current assets | 24 | 56 | 182 | | 262 |
| Intangible assets held-for-sale | 78 | | 1 | | 79 |
| Total other assets | 5,447 | 852 | 14,864 | (16,411) | 4,752 |
| **Total Assets** | $ 18,816 | $ 1,815 | $ 15,962 | $ (17,158) | $ 19,435 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | | | | |
| **Current Liabilities** | | | | | |
| Current portion of long-term debt | $ 460 | $ 101 | $ 37 | $ (468) | $ 130 |
| Accounts Payable | (682) | 287 | 727 | | 332 |
| Derivative instruments valuation | 964 | | | | 964 |
| Deferred income taxes | 23 | 7 | 134 | | 164 |
| Accrued expenses and other current liabilities | 509 | 53 | 160 | (280) | 442 |

| | | | | | |
|---|---|---|---|---|---|
| Total current liabilities | 1,274 | 448 | 1,058 | (748) | 2,032 |
| **Other Liabilities** | | | | | |
| Long-term debt and capital lease | 5,504 | 869 | 8,791 | (6,517) | 8,647 |
| Nuclear decommissioning reserve | 289 | | | | 289 |
| Nuclear decommissioning trust liability | 324 | | | | 324 |
| Deferred income taxes | 494 | (104) | 164 | | 554 |
| Derivative instruments valuation | 325 | 6 | 20 | | 351 |
| Out-of-market contracts | 897 | | | | 897 |
| Other non-current liabilities | 385 | 26 | 24 | | 435 |
| Total non-current liabilities | 8,218 | 797 | 8,999 | (6,517) | 11,497 |
| **Total liabilities** | 9,492 | 1,245 | 10,057 | (7,265) | 13,529 |
| Minority interest | | 1 | | | 1 |
| 3.625% Preferred Stock | | | 247 | | 247 |
| **Stockholders Equity** | 9,324 | 569 | 5,658 | (9,893) | 5,658 |
| **Total Liabilities and Stockholders Equity** | $ 18,816 | $ 1,815 | $ 15,962 | $ (17,158) | $ 19,435 |

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

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**NRG Energy, Inc. and Subsidiaries**
**Condensed Consolidating Statements of Cash Flows**
**For the Six Months Ended June 30, 2006**
**(Unaudited)**

| (In millions) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | NRG Energy, Inc. (Note Issuer) | Eliminations[a] | Consolidated Balance |
|---|---|---|---|---|---|
| **Cash Flows from Operating Activities** | | | | | |
| Net income | $ 368 | $ 99 | $ 229 | $ (467) | $ 229 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | | | |
| Distributions less than equity earnings of unconsolidated affiliates and consolidated subsidiaries | (37) | (12) | (431) | 467 | (13) |
| Depreciation and amortization of nuclear fuel | 279 | 24 | 5 | | 308 |
| Amortization and write-off of financing costs and debt discount/premiums | | | 63 | | 63 |
| Amortization of intangibles and out-of-market contracts | (206) | (5) | | | (211) |
| Amortization of unearned equity compensation | | | 9 | | 9 |
| Changes in deferred income taxes | 46 | (1) | 51 | | 96 |
| Changes in derivatives | 24 | (11) | (54) | | (41) |
| Changes in nuclear decommissioning liability | 3 | | | | 3 |
| Changes in collateral deposits supporting energy risk management activities | 272 | | | | 272 |
| Gain on legal settlement | | (67) | | | (67) |
| Gain on sale of emission allowances | (67) | | | | (67) |
| Loss on sale of assets | 3 | | | | 3 |
| Gain on sale of discontinued operations | | (10) | | | (10) |
| Write down and gains on sale of equity method investments | 2 | (13) | | | (11) |
| Cash provided by/(used by) changes in other working capital, net of dispositions affects | (212) | 27 | 299 | | 114 |

| | | | | | |
|---|---|---|---|---|---|
| **Net Cash Provided by Operating Activities** | 475 | 31 | 171 | | 677 |
| **Cash Flows from Investing Activities** | | | | | |
| Acquisition of Texas Genco LLC and WCP, net of cash acquired | | | (4,328) | | (4,328) |
| Capital expenditures | (59) | (13) | (2) | | (74) |
| Increase in restricted cash, net | | (9) | | | (9) |
| Decrease in notes receivable | (914) | 14 | (3,318) | 4,232 | 14 |
| Purchases of emission allowances | (78) | | | | (78) |
| Proceeds from sale of emission allowances | 84 | | | | 84 |
| Investments in nuclear decommissioning trust fund securities | (106) | | | | (106) |
| Proceeds from sale of nuclear decommissioning trust fund securities | 103 | | | | 103 |
| Proceeds from sale of assets | | 1 | | | 1 |
| Proceeds from sale of investments | 63 | 23 | | | 86 |
| Proceeds from sale of discontinued operations | | 15 | | | 15 |
| **Net Cash Provided/Used by Investing Activities** | (907) | 31 | (7,648) | 4,232 | (4,292) |
| **Cash Flows from Financing Activities** | | | | | |
| Proceeds from Intercompany Loans | 3,318 | | 914 | (4,232) | |
| Payments for dividends to preferred stockholders | | | (23) | | (23) |
| Payment of financing element of acquired derivatives | (73) | | | | (73) |
| Payments for treasury stock | | | | | |
| Funded letter of credit | | | 350 | | 350 |
| Proceeds from issuance of common stock, net of issuance costs | | | 986 | | 986 |
| Proceeds from issuance of preferred shares, net of issuance cost | | | 486 | | 486 |
| Proceeds from issuance of long-term debt | | | 7,175 | | 7,175 |
| Payment of deferred debt issuance costs | | | (164) | | (164) |
| Payments for short and long-term debt | (2,772) | (14) | (1,876) | | (4,662) |
| **Net Cash Used by Financing Activities** | 473 | (14) | 7,848 | (4,232) | 4,075 |
| Change in Cash from Discontinued Operations | | 1 | 1 | | 2 |
| | | 3 | | | 3 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Effect of Exchange Rate Changes on Cash and Cash Equivalents | | | | | | | | | | |
| **Net Increase in Cash and Cash Equivalent** | | 41 | | 52 | | 372 | | | | 465 |
| **Cash and Cash Equivalents at Beginning of Period** | | (7) | | 78 | | 422 | | | | 493 |
| **Cash and Cash Equivalents at End of Period** | $ | 34 | $ | 130 | $ | 794 | $ | | $ | 958 |

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

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## Item 2 Management s Discussion and Analysis of Financial Conditions and Results of Operations

### Introduction and Overview

NRG Energy, Inc., NRG, or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is 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 trading of energy, capacity and related products in the United States and select international markets. As of June 30, 2007, NRG had a total global portfolio of 187 active operating generation units at 48 power generation plants, with an aggregate generation capacity of approximately 23,900 MW. Within the United States, the Company has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,660 MW of generation capacity in 171 active generating units at 42 plants. These power generation facilities are primarily located in Texas (approximately 10,845 MW), and the Northeast (approximately 6,980 MW), South Central (approximately 2,850 MW), and the West (approximately 1,870 MW) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets. NRG s principal domestic power plants consist of a diversified mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 46%, 33%, 16% and 5% of the Company s total domestic generation capacity, respectively. In addition, 15% of NRG s domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option. NRG s domestic generation facilities primarily consist of baseload, intermediate and peaking power generation facilities, which are referred to as the Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s diverse generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

The direction in which we are taking the Company is reflected in our Five Major Initiatives, four that we announced and began to implement during 2006 and the fifth, Focus on ROIC at NRG , or *FOR*NRG, that has successfully concluded its second year. NRG s Five Major Initiatives, described below, are designed to enable the Company to take advantage of the opportunities, and surmount the challenges presented by the power industry.

1. ***FOR*NRG** is a companywide initiative, introduced in 2005, designed to improve the financial performance of the Company s existing asset base through an extensive range of endeavors that cut costs and boost performance with the goal of increasing its return on invested capital, or ROIC.

2. ***RepoweringNRG*** is our program designed to develop, finance, construct and operate over 10,000 MW of new, highly efficient, environmentally responsible capacity over the next decade, at an estimated total cost of approximately $16 billion. In connection with NRG s acquisition of Padoma Wind Power LLC, the Company has and will continue to actively evaluate and potentially develop or construct domestic terrestrial wind projects as part of the *RepoweringNRG* program.

3. **econrg** represents NRG s commitment to continually move toward more environmentally responsible generation. econrg seeks to find ways to meet the challenges of climate change, clean air and protecting our natural resources. econrg builds upon its foundation in environmental compliance and embraces environmental initiatives for the benefit of our communities, employees and shareholders, such as encouraging investment in new environmental technologies, pursuing activities that preserve and protect the environment and encouraging changes in the daily lives of our employees.

4. **Future NRG** is our workforce planning and development initiative and represents the Company s strong commitment to planning for future staffing requirements to meet the on-going needs of our current operations in addition to the new repowering initiatives. Future NRG encompasses analyzing the demographics, skill set and size of the Company s workforce in addition to the organizational structure. It then determines succession planning requirements, training, development, staffing and recruiting needs and develops programs and

processes to address these needs. Included under the Future NRG umbrella is NRG University, which develops leadership, managerial, supervisory and technical training programs as well as individual skill development courses.

5. **NRG Global Giving -** Responsible corporate citizenship is one of NRG s core values. Our Global Giving Program invests NRG s resources to strengthen the communities where we do business and seeks to make community investments in four FOCUS areas: community and economic development, education, environment and human welfare.

NRG s 2006 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 six months ended June 30, 2007 and 2006. 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;*

*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; and*

*new and on-going Company initiatives that will affect NRG s results of operations and financial condition in the future.*

**Stock Split**

On April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. All share and per share amounts in the consolidated results of operations and financial position as well as in the notes to the financial statements retroactively reflect the effect of the stock split.

**Changes in Accounting Standards**

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

**Regulatory Matters**

As an operator of power plants and a participant in the wholesale markets, NRG is subject to regulation by various federal and state government agencies. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO markets in which NRG participates. These wholesale power markets are subject to ongoing legislative and regulatory changes. In some of NRG s regions, interested parties have advocated for material market design changes, including the elimination of a single clearing price mechanism, as well as proposals to re-regulate the markets or require divestiture by generating companies in order to reduce their market share. The Company cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on NRG s business.

NRG filed its most recent triennial update of its market power analysis on March 26, 2007, and this filing remains pending before FERC. On June 21, 2007, FERC issued its long-awaited final rule on market-based rates for wholesale sales of electric energy, capacity, and ancillary services. Of particular note to NRG, the new rule now requires applicants to use submarkets within an RTO region as the relevant geographic market, specifically identifying Southwest Connecticut (and the Connecticut Import interface), New York City, and PJM East as such submarkets. The impact of this rule, and any additional mitigation that may be imposed by FERC as a result of a determination of market power in a submarket, cannot be determined at this time. The Company has sought rehearing/clarification of this rule.

**Environmental Matters**

On June 20, 2007, the USEPA released its proposal to strengthen the National Ambient Air Quality Standards, or NAAQS, for ground level ozone. USEPA proposes to lower the primary NAAQS (8-hour average) to a level in the range of 0.070 to 0.075 parts per million or ppm, from 0.08. Under the terms of a consent decree, USEPA must issue final standards by March 12, 2008. Such a new standard could result in a significant increase in non-attainment areas in the country. New designations should be finalized by 2010 and states must provide implementation plans to achieve compliance by 2013. Tightening of the standards could result in additional requirements to control $NO_x$ from power plants in the states in which NRG operates.

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**Consolidated Results of Operations**

The following table provides selected financial information for NRG Energy, Inc., for the three and six months ended June 30, 2007 and 2006:

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| **(In millions except otherwise noted)** | **2007** | **2006** | **Change %** | **2007** | **2006** | **Change %** |
| **Operating Revenues** | | | | | | |
| Energy revenue | $ 1,067 | $ 802 | 33% | $ 2,014 | $ 1,355 | 49% |
| Capacity revenue | 288 | 405 | (29) | 562 | 695 | (19) |
| Risk management activities | 52 | 12 | 333 | 9 | 36 | (75) |
| Contract amortization | 67 | 226 | (70) | 119 | 271 | (56) |
| Thermal revenue | 29 | 27 | 7 | 70 | 65 | 8 |
| Other revenues | 45 | 30 | 50 | 84 | 115 | (27) |
| Total operating revenues | 1,548 | 1,502 | 3 | 2,858 | 2,537 | 13 |
| **Operating Costs and Expenses** | | | | | | |
| Cost of operations | 843 | 832 | 1 | 1,627 | 1,482 | 10 |
| Depreciation and amortization | 161 | 177 | (9) | 322 | 295 | 9 |
| General and administrative | 71 | 83 | (14) | 157 | 141 | 11 |
| Development costs | 36 | | NA | 59 | | NA |
| Total operating costs and expenses | 1,111 | 1,092 | 2 | 2,165 | 1,918 | 13 |
| Gain/(loss) on sale of assets | (1) | | NA | 16 | | NA |
| **Operating income** | 436 | 410 | 6 | 709 | 619 | 15 |
| **Other Income/(Expense)** | | | | | | |
| Equity in earnings of unconsolidated affiliates | 8 | 8 | | 21 | 29 | (28) |
| Write downs and gains on sales of equity method investments | 1 | 14 | (93) | 1 | 11 | (91) |
| Other income, net | 14 | 8 | 75 | 30 | 88 | (66) |
| Refinancing expenses | (35) | | NA | (35) | (178) | (80) |
| Interest expense | (174) | (151) | 15 | (355) | (266) | 33 |
| Total other income/(expenses) | (186) | (121) | 54 | (338) | (316) | 7 |
| **Income from Continuing Operations before income tax expense** | 250 | 289 | (13) | 371 | 303 | 22 |
| Income tax expense | 101 | 87 | 16 | 157 | 86 | 83 |
| **Income from Continuing Operations** | 149 | 202 | (26) | 214 | 217 | (1) |
| Income from discontinued operations, net of income tax expense | | 1 | NA | | 12 | NA |
| **Net Income** | $ 149 | $ 203 | (27) | $ 214 | $ 229 | (7) |

**Business Metrics**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Average natural gas price Henry Hub ($/MMBtu) | | 7.65 | 6.67 | 15% | 7.42 | 7.28 | 2% |

*NA Not Applicable*

**Significant Items Reflected in NRG s Results of Operations during the six months ended June 30, 2007**

*Impact of Hedge Reset* energy revenue increased by $145 million as average contract prices for the period increased by approximately $10 per MWh

*Acquisition of Texas and WCP* due to the inclusion of the Texas and WCP results for the entire six month period, operating income increased by approximately $74 million

*New capacity markets* with the introduction of the Locational Forward Reserve Market, or LFRM, the Reliability Pricing Model market, or RPM, and transition capacity payment markets, capacity revenues in the Northeast region increased by $35 million

*Development costs* incurred $59 million in development costs due to progress with licensing new units at the STP nuclear site as well as other *RepoweringNRG* projects

*Refinancing expense* recognized a $35 million write-off of previously deferred financing cost due to the refinancing of the Company s Term B loan

*Interest expense* following the increase in debt due to the Texas acquisition, Hedge Reset and Capital Allocation Program, interest expense increased by approximately $89 million

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**Management s discussion of the results of operations for the three months ended June 30, 2007 and 2006**

***Operating Revenues***

Operating revenues increased by $46 million during the three months ended June 30, 2007, compared to 2006. This was due to:

- *Energy revenues* energy revenues increased by $265 million during the three months ended June 30, 2007, compared to 2006:

  *Texas* - energy revenues increased by $204 million of which $106 million was due to the Hedge Reset as average forward prices for the period increased by approximately $12 per MWh for 2007 compared to 2006. The remaining increase was due to a reduction of the PUCT auctioned capacity that is now being sold in the merchant market. Prior to the Acquisition, PUCT regulations required that Texas sell 15% of its capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG s request to no longer participate in these auctions and that capacity is now being sold in the merchant market.

  *Northeast* - energy revenues increased by approximately $56 million of which $36 million was due to an average increase in prices of 16%, and approximately $17 million due to a 9% increase in generation. On average, prices in the Northeast region increased by 16% compared to 2006 due to a 15% increase in natural gas prices coupled with transmission constraints in the New York City area. Generation increased by 226 thousand MWh at the Arthur Kill plant due to its locational advantage following transmission constraints around New York City.

  *South Central* energy revenues increased by $29 million due to a new contract with a local utility and an increase in Co-op contract prices driven by the updated pass-through of actual fuel costs.

- *Capacity revenues* capacity revenues decreased by $117 million during the three months ended June 30, 2007, compared to 2006, due to a decrease in Texas that was partially offset by increases in the Northeast, South Central and West regions:

  *Texas* - capacity revenues decreased by $134 million due to a reduction of capacity auction sales mandated by the PUCT in prior years, as explained above.

  *Northeast* - capacity revenues increased by $2 million this increase was due to a mix of a $15 million increase from the New England Power Pool, or NEPOOL, assets, $5 million from the new RPM capacity market offset by decreases of $5 million in New York capacity revenues, and by $13 million from the expiration of the region s Devon facility s RMR capacity agreement on December 31, 2006. The NEPOOL assets benefited from the new LFRM market and transition capacity market, both introduced in the fourth quarter of 2006. New York capacity revenues decreased as it realized lower capacity prices during the second quarter of 2007 as compared to 2006.

  *South Central* - capacity revenues increased by $5 million due to increased billed capacity volumes of 482 thousand KW following increased demand during 2006 and additional capacity payments from a new contract with the local utility.

  *West* - capacity revenues increased by $9 million due to tolling agreements at the El Segundo and Encina plants that will expire in April 2008 and December 2009, respectively.

- *Contract amortization* - revenues from contract amortization decreased by $159 million during the three months ended June 30, 2007, compared to 2006, as a result of the Hedge Reset transaction in November 2006 which resulted in the write-off of a large portion of out-of-market power contracts which are amortized as revenue.

- *Other revenues* other revenues increased by $15 million during the three months ended June 30, 2007 compared to 2006 due to the following factors:

*Trading of natural gas* with natural gas generation decreasing by 38%, the Company sold its excess natural gas to third parties increasing other revenues by approximately $4 million. This amount reflects the net profit from the sale and purchase of natural gas.

*Sale of $SO_2$ allowances* net sales of emission allowances increased by $9 million during the period. Although market prices decreased by 16% during 2007 as compared to 2006, the Company increased its sales activity of emission allowances as pricing opportunities arose.

*Ancillary revenues* the Company s revenues from ancillary services increased by approximately $5 million due to a change in strategy which increased the Company s participation in the ancillary services market in the Texas region in lieu of merchant revenues.

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o *Risk management activities* revenues from risk management activities include all derivative activity that does not qualify for hedge accounting as well as the ineffective portion associated with hedged transactions. Such revenues increased to $52 million for the three months ended June 30, 2007 from $12 million for the three months ended June 30, 2006. The breakdown of changes by region are as follows:

| | **Three months ended June 30, 2007** | | | | **Three months ended June 30, 2006** | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **Northeast** | **South Central** | **Total** | **Texas** | **Northeast** | **South Central** | **All Other** | **Total** |
| Net gains/(losses) on settled positions, or financial revenues | $ (2) | $ 7 | $ 4 | $ 9 | $ (45) | $ (11) | $ 1 | $ | $ (55) |
| **Mark-to-market results** | | | | | | | | | |
| Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges | (23) | (12) | | (35) | | 20 | | | 20 |
| Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity | | (3) | (5) | (8) | | (3) | | | (3) |
| Net unrealized gains/(losses) on open positions related to economic hedges | 48 | 31 | | 79 | 53 | (5) | (2) | (1) | 45 |
| Net unrealized gains on open positions related to trading activity | 3 | 1 | 3 | 7 | | 5 | | | 5 |
| **Subtotal mark-to-market results** | 28 | 17 | (2) | 43 | 53 | 17 | (2) | (1) | 67 |
| Total derivative gain/(losses) | $ 26 | $ 24 | $ 2 | $ 52 | $ 8 | $ 6 | $ (1) | $ (1) | $ 12 |

NRG s second quarter 2007 gain was comprised of $43 million of mark-to-market gains and $9 million in settled gains, or financial revenue. Of the $43 million of mark-to-market gains, $35 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $8 million from the reversal of mark-to-market gains previously recognized on trading activity. Both of these gains ultimately settled as financial revenues during 2007. The $79 million gain from economic hedge positions was comprised of a $100 million increase in value of forward sales of electricity and fuel due to favorable power and gas prices offset by a $21 million net loss from hedge accounting ineffectiveness. This ineffectiveness was related to gas swaps and collars in the Texas region due to a change in the correlation as of June 30, 2007, between natural gas and power prices, partially offset in the Northeast region by a change in the correlation between power prices in the Company s delivery points and PJM West.

Since these hedging 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 are afforded hedge accounting treatment) and cost of energy.

***Cost of Operations***

Cost of operations for the three months ended June 30, 2007, increased by $11 million compared to 2006, however as a percentage of revenues remained unchanged at 55% in both 2006 and 2007:

- *Cost of energy* cost of energy decreased by approximately $8 million during the three month period ended June 30, 2007, compared to 2006. This decrease was due to:

  *Texas* Texas expense decreased by $32 million during the period. Natural gas expenses decreased by $61 million due to a 38% reduction in gas-fired generation due to milder weather during 2007 as compared to 2006, coupled with greater economic purchases and increased baseload generation. This decrease was offset by an $8 million increase in coal costs and a $6 million increase in emission amortization due to an 11% increase in coal-fired generation following less planned outages during 2007. Also, ancillary costs increased by $9 million as Texas is now actively providing ancillary services in the Texas region.

  *Northeast* - Northeast expenses increased by $22 million due to a 9% increase in generation. Gas expense increased by $27 million due to the increased generation at our Arthur Kill facility following its locational advantage in the transmission constrained area of New York City, offset by a $5 million reduction in our oil-fired generation in our NEPOOL region whose generation decreased due to transmission improvements in Connecticut thus reducing the extent of transmission support from our assets together with lower economic dispatch on oil fired units due to rising prices for residual fuel oil.

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*South Central* although South Central generation was relatively flat, cost of energy increased by $24 million. Purchased power increased due to more reliance on the region s tolling agreements during the second quarter 2007 as compared to 2006 to support load requirements and merchant sales. Costs also increased by $5 million due to higher coal and transportation costs related to contractual rate increases. In addition, transmission costs increased by $4 million due to contractual increases in transmission rates.

o *Other operating costs* Other operating costs increased by $19 million during the three month period ended June 30, 2007, compared to 2006. This increase was due to:

*Planned outages* operations and maintenance, or O & M, expense increased by $29 million due to the planned refueling outage at STP offset by less outages at our coal-fired plants and gas-fired plants.

*Higher utility and auxiliary power* - of approximately $18 million due to the reversal of an $18 million accrual during 2006 related to a favorable court decision on station service obligations at the region s Western New York plants.

*Property taxes* property taxes decreased by approximately $11 million due to an adjustment to the Company s year-to-date accrual and a tax law change. Final tax assessments for the Texas assets resulted in reduction of $7 million in property taxes for 2007 that was recognized during the quarter. In addition, there was a $5 million reduction in property taxes in the Northeast region during the three months ended June 30, 2007 as compared to 2006 due to a change in tax law that resulted in a reduction of such tax credits during 2006.

***Depreciation and Amortization***

NRG s depreciation and amortization expense for the three months ended June 30, 2007 decreased by $16 million compared to 2006. A decrease of approximately $17 million was the result of additional depreciation expense during 2006 due to lower estimated weighted average useful lives of the Texas assets following acquisition, coupled by catch-up estimates for the first quarter of 2006 that were recorded during the second quarter of 2006.

***General and Administrative***

NRG s general and administrative, or G&A, costs for the three months ended June 30, 2007 decreased by $12 million compared to 2006, and as a percentage of revenues it decreased from 6% in 2006 to 5% in 2007. This decrease was due to:

o *Non-recurring expenses during 2006* during the second quarter of 2006 G&A included non-recurring fees of $11 million of which $6 million were related to the unsolicited takeover attempt by Mirant Corporation and $5 million associated with the Texas integration efforts.

***Development Costs***

NRG s development costs were $36 million for the three months ended June 30, 2007. These costs were due to the Company s *RepoweringNRG* projects:

o *Texas* costs to develop nuclear units 3 and 4 at STP accounted for approximately $23 million of the Company s second quarter 2007 development costs.

o *Wind projects* approximately $4 million in development costs related to wind projects primarily in Texas.

- *Other project*  approximately $8 million in development costs related to other *RepoweringNRG* projects primarily in the Northeast and West regions.

***Interest Expense***

NRG  s interest expense for the three months ended June 30, 2007 increased by $23 million compared to 2006. This increase was due to:

- *Increase of $1.1 billion in debt for Hedge Reset*  the Company issued $1.1 billion in Senior Notes due 2017 in November 2006 related to the Hedge Reset, which increased interest expense by $20 million.

- *Capital Allocation Program*  the Company issued a total of $330 million of debt to fund Phase I of the Capital Allocation Program during the second half of 2006, increasing interest expense by $7 million.

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- o *Repayment of $400 million of Term Loan* in December 2006 the Company repaid $400 million of its Term B loan, reducing interest expense by approximately $7 million.

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 s financial results. For the three months ended June 30, 2007, NRG had deferred a gain of $21 million in other comprehensive income compared to deferred gains of $32 million in 2006.

***Refinancing Expense***

Refinancing expense increased by $35 million during the three months ended June 30, 2007, compared to 2006 due to the initiation of the Comprehensive Capital Allocation Plan which was implemented during the second quarter 2007. On June 8, 2007, NRG completed the $4.4 billion refinancing of the Company s Senior Credit Facility previously announced on May 2, 2007. The transaction resulted in a 0.25% reduction on the spread that the Company pays on its Term B loan and Synthetic Letter of Credit facility, a $200 million reduction in the Synthetic Letter of Credit Facility to $1.3 billion, and various amendments to provide improved flexibility, efficiency for returning capital to shareholders, asset repowering and investment opportunities. The pricing on the Company s Term B loan and Synthetic Letter of Credit is also subject to further reductions upon the achievement of certain financial ratios. The refinancing resulted in a charge of approximately $35 million to the current period s results of operations that were primarily related to the write-off of deferred financing costs as the lenders for approximately 45% of the Term B loan either exited the financing or reduced their holdings and were replaced by other institutions.

***Income Tax Expense***

Income tax expense increased by $14 million during the three months ended June 30, 2007, compared to 2006. The effective tax rate was 40.4% and 30.1% for the three months ended June 30, 2007 and 2006, respectively. The increase in tax expense was due to a large distribution from the Company s claimants reserve during the second quarter of 2006 compared to an increase in non-deductible expenses during 2007, despite a reduction in income:

- o *Decrease in profits* - income before tax decreased by $39 million, with a corresponding decrease of approximately $14 million in tax expense.

- o *Permanent differences*

  *Payment from claimants reserve* - during the second quarter 2006, the Company distributed payments from its disputed claims reserve that reduced income tax expense by approximately $21 million.

  *Taxable dividends from foreign subsidiaries* - in January 2007 the Company transferred the proceeds from the sale of its Flinders assets to the US creating additional tax expense of approximately $3 million.

  *Lower tax rates in foreign jurisdictions* lower tax rates at the Company s foreign locations benefited the Company during 2006 by an additional $5 million as opposed to 2007.

  *Non-deductible interest* interest expense from the stock buybacks from Phase I of the Company s Capital Allocation Program increased tax expense by approximately $3 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.

**Management s discussion of the results of operations for the six months ended June 30, 2007 and 2006**

***Operating Revenues***

Operating revenues increased by $321 million during the six months ended June 30, 2007, compared to 2006. This was due to:

- o *Energy revenues* energy revenues increased by $659 million during the six months ended June 30, 2007, compared to 2006:

*Texas* - energy revenues increased by $537 million, of which $217 million was due to the inclusion of six months activity in 2007 compared to five months in 2006, and $145 million is due to the Hedge Reset as the period s average forward prices increased by approximately $10 per MWh for 2007 compared to 2006. The remaining increase was due to a reduction of PUCT auctioned capacity that is now being sold in the merchant market at higher prices. Prior to the Acquisition, PUCT regulations required that Texas sell 15% of its capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG s request to discontinue these auctions and such capacity is now being sold in the merchant market at higher prices.

*Northeast* - energy revenues increased by approximately $105 million, with $43 million the result of increased generation, $50 million due to increased prices per MWh and $12 million from new contracted energy revenues. Generation increased by 10% in the first half 2007 compared to 2006, of which 194 thousand MWh was from the region s Arthur Kill plant primarily due to transmission constraints around New York City, the region s Oswego plant whose generation increased by 135 thousand MWh due to a relatively colder winter during 2007 compared to 2006, and an increase of 116 thousand MWh from the Company s NEPOOL assets due to an extended outage of a baseload plant in the region as well as a colder winter. On average, prices in the Northeast region increased by 12% compared to 2006 due to a 15% increase in natural gas prices during the second quarter 2007 coupled with a 17% price increase in the New York City area following the said transmission constraints.

*South Central* - energy revenues increased by $38 million primarily due to a new contract with a local utility. Contract energy revenues increased by $40 million due to a new contract and a 6% increase in Co-op contract prices as they were updated for the pass-through of actual fuel costs.

o *Capacity revenues* capacity revenues decreased by $133 million during the six months ended June 30, 2007, compared to 2006, due to a decrease in Texas capacity revenues that were partially offset by increases in capacity revenues in the Northeast, South Central and West regions:

*Texas* capacity revenues decreased by $207 million due to a reduction of auction sales mandated by the PUCT in prior years as described above.

*Northeast* capacity revenues increased by $27 million $13 million of the increase was from the Company s NEPOOL assets, $9 million was from New York Rest of State assets and $5 million was from the Company s PJM assets. The NEPOOL assets benefited from the new LFRM market and transition capacity market, both introduced in the fourth quarter 2006. During the six months ended June 30, 2007, capacity revenues increased by $17 million from the LFRM market and $13 million from transition capacity payments, offset by a reduction in capacity payments of $15 million due to the expiration of an RMR agreement for the Company s Devon plant on December 31, 2006. New York Rest of State capacity prices increased by 109% during the first half 2007 compared to 2006 as load requirement growth increased demand for capacity, coupled with the impact from the new capacity markets in NEPOOL which reduced exported supply into the New York market that further improved the supply/demand dynamics. On June 1, 2007, the new RPM capacity market became effective in PJM increasing capacity revenues by $5 million as compared to the first half of 2006.

*South Central* capacity revenues increased by $10 million due to increased capacity volumes following increased demand during 2006 which in turn increased billable capacity volumes by 482 thousand KW during 2007, and increased capacity payments to the Rockford facilities.

*West* capacity revenues increased by $35 million, of which $26 million was due to the consolidation of WCP s results for a full six month period during 2007 as opposed to three months during 2006 and $10 million were for tolling agreements at the El Segundo and Encina plants that will expire in April 2008 and December 2009, respectively.

o *Contract amortization* revenues from contract amortization decreased by $152 million during the six months ended June 30, 2007, compared to 2006, as a result of $23 million of amortization of in-the-market power contracts acquired with Texas Genco LLC that were fully amortized in 2006 and the balance is primarily due to the November 2006 Hedge Reset transaction, which resulted in the write-off of a large portion of the Company s out-of-market power contracts.

- o *Other revenues* other revenues decreased by $31 million during the six months ended June 30, 2007 compared to 2006 due to the following factors:

  *Ancillary revenues* the Company s revenues from ancillary services increased by approximately $13 million due to a change in strategy to actively provide ancillary services in the Texas region which increased revenues by $19 million, partially offset by a $4 million reduction in ancillary services in the Northeast region due to higher transmission costs.

  *Sale of $SO_2$ allowances* net sales of emission allowances decreased by $44 million due to increased generation and a decrease in sales activity following a 43% reduction in market prices.

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o *Risk management activities* revenues from risk management activities include all derivative activity that does not qualify for hedge accounting as well as the ineffective portion associated with hedged transactions. Such revenues decreased to $9 million for the six months ended June 30, 2007 from $36 million for the six months ended June 30, 2006. The breakdown of changes by region are as follows:

| | **Six months ended June 30, 2007** | | | | **Six months ended June 30, 2006** | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **Northeast** | **South Central** | **Total** | **Texas (a)** | **Northeast** | **South Central** | **All Other** | **Total** |
| Net gains/(losses) on settled positions, or financial revenues | $ 16 | $ 36 | $ 4 | $ 56 | $ (73) | $ (12) | $ 4 | $ | $ (81) |
| **Mark-to-market results** | | | | | | | | | |
| Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges | (54) | (38) | | (92) | | 65 | | | 65 |
| Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity | 1 | (12) | (10) | (21) | | (27) | | | (27) |
| Net unrealized gains/(losses) on open positions related to economic hedges | 38 | 6 | | 44 | 51 | 25 | | (1) | 75 |
| Net unrealized gains on open positions related to trading activity | 5 | 3 | 14 | 22 | | 4 | | | 4 |
| **Subtotal mark-to-market results** | (10) | (41) | 4 | (47) | 51 | 67 | | (1) | 117 |
| Total derivative gain/(losses) | $ 6 | $ (5) | $ 8 | $ 9 | $ (22) | $ 55 | $ 4 | $ (1) | $ 36 |

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

NRG s 2007 gain was comprised of $47 million of mark-to-market losses and $56 million in settled gains, or financial revenue. Of the $47 million of mark-to-market losses, $92 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $21 million from the reversal of mark-to-market gains previously recognized on trading activity. Both of these gains ultimately settled as financial revenues during 2007. The $44 million gain from economic hedge positions was comprised of a $21 million increase in the value of forward sales of electricity and fuel due to favorable power and gas prices and a $23 million gain from hedge accounting ineffectiveness. This ineffectiveness was related to gas swaps and collars in the Texas region due to a change in the correlation as at June 30, 2007, between natural gas and power prices, and in the Northeast region due to a change in the correlation between power prices in the Company s delivery points and PJM West.

Since these hedging 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 are afforded hedge accounting treatment) and cost of energy.

***Cost of Operations***

Cost of operations for the six months ended June 30, 2007, increased by $145 million compared to 2006, but as a percentage of revenues it decreased from 58% for the six months ended June 30, 2006 to 57% for the six months ended June 30, 2007.

- o *Cost of energy* cost of energy increased by approximately $53 million during the first half of 2007 as compared to 2006, and as a percentage of revenue it decreased from 43% for the six months ended June 30, 2006 to 40% for the six months ended June 30, 2007. This increase was due to:
  - *Texas* cost of energy decreased by $13 million, however, excluding January 2007 expense of $96 million in 2007, cost of energy decreased by $109 million. This decrease was due to a reduction in gas expense, purchased power and fuel contract amortization, partially offset by increased ancillary service expense.
    - *Gas expense* decreased by $82 million due to a decrease of 1 million MWh during the period following milder weather coupled with greater economic purchases from ERCOT and increased baseload generation.
    - *Purchased power* decreased by $27 million due to forced outages in 2006 at the region s Parish and Limestone plants.
    - *Amortized fuel costs* decreased by approximately $16 million during 2007 as compared to 2006.

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*Purchased ancillary service expense* increased by approximately $15 million due to the favorable market price in purchasing this service in the market as opposed to providing the service from internal resources.

*Northeast* cost of energy increased by $35 million due to increased oil and natural gas costs, offset by lower emission amortization and coal costs.

*Oil costs* increased by approximately $28 million was due to an increase in generation of 308 thousand MWh at the region s oil-fired plants due to a relatively colder winter during 2007 compared to 2006.

*Natural gas costs* - increased by approximately $19 million as a result of increased generation at the Company s Arthur Kill plant due to its locational advantage to New York City following transmission constraints during the second quarter 2007.

*Emission allowance amortization* - decreased by approximately $9 million in amortization expense due to a reduction in the value of the Company s emission allowances.

*Coal costs* despite increased generation of 126 thousand MWh at the Company s coal-fired plants, coal costs decreased by $4 million due to lower average cost of generation from the region s coal-fired assets as a result of lower average prices of purchased coal. In addition, an extended outage at the region s Indian River facility further contributed to the decline in the Company s coal costs as compared to 2006.

*South Central* Cost of energy increased by $46 million due to increases in purchased power, coal expense and transmission expense.

*Purchased power* - increased by approximately $29 million primarily from increased market purchases due to planned maintenance.

*Coal expense* increased by approximately $12 million due to an average increase to the cost per MMBtu of $0.25 following higher fuel charges and new contract rates.

*Transmission expense* increased by approximately $8 million due to the region s merchant sales outside the Entergy market as well as purchasing power outside the Entergy market. Due to transmission constraints in the Entergy market, both the sale and purchase of power was limited in the region, increasing transmission expense.

o *Other operating costs* Other operating costs increased by $92 million during the six months ended June 30, 2007, compared to 2006. This increase was due to:

*Texas* other operating costs increased by $52 million, however, when excluding the January 2007 expense of $38 million, other operating costs increased by $14 million. This increase was due to a refueling outage at STP and increased maintenance at the region s gas plants, offset by reduced maintenance to the region s coal-fired plants. During 2007, an STP refueling outage increased maintenance expense by $16 million, and maintenance expense at the gas plants increased by $7 million. These increases were partially offset by a $10 million of lower maintenance costs at the region s coal-fired plants because of reduced planned outage time in 2007.

*Northeast* other operating costs increased by $15 million due to the reversal of an $18 million accrual during 2006 following the favorable court decision related to station service obligations at the region s Western New York plants.

*Acquisition of WCP* these results include $14 million of WCP expenses that were not included in the Company s results in 2006, as well as $6 million from increased maintenance work at the region s Encina and El Segundo facilities to ensure availability due to new tolling agreements.

***Depreciation and Amortization***

NRG s depreciation and amortization expense for the six months ended June 30, 2007 increased by $27 million compared to 2006. This increase was primarily due to:

- *Texas acquisition* - the inclusion of Texas results for six months in 2007 compared to five months in 2006 resulted in an increase of approximately $38 million that was offset by higher depreciation estimates of approximately $15 million during 2006 as compared to 2007.

- *Impact of new environmental legislation* Due to new and more restrictive environmental legislation, the useful life of certain pollution control equipment has been reduced. The Company accelerated depreciation on certain of these equipment to reflect the remaining useful life, resulting in increased depreciation of approximately $5 million.

***General and Administrative***

NRG s general and administrative, or G&A, costs for the six months ended June 30, 2007 increased by $16 million compared to 2006, and as a percentage of revenues was 6% in 2006 and 5% in 2007. This increase was due to:

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- o *Texas acquisition* - the inclusion of Texas results for six months in 2007 compared to five months in 2006 resulted in an increase of approximately $7 million.

- o *Wage and Benefit Costs* due to the expansion of the Company including *RepoweringNRG* initiatives, head count increased coupled with related benefit costs that resulted in a $7 million increase in G&A.

- o *Franchise tax* the Company s Louisiana state franchise tax increased by approximately $7 million. This is because the state franchise tax is assessed based on the Company s total debt and equity that significantly increased following the acquisition of Texas Genco LLC.

- o *Non-recurring expenses during 2006* during the second quarter 2006 G&A included non-recurring fees of $11 million of which $6 million were related to the unsolicited takeover attempt by Mirant Corporation and $5 million associated with the Texas integration efforts.

***Development Costs***

NRG s development costs were $59 million for the six months ended June 30, 2007. These costs were due to the Company s *RepoweringNRG* projects:

- o *Texas* Costs to develop nuclear units 3 and 4 at STP accounted for approximately $39 million of the Company s development costs.

- o *Wind projects* approximately $6 million in development costs related to wind projects primarily in Texas.

- o *Other project* approximately $14 million in development costs related to other *RepoweringNRG* project primarily in the Northeast and West regions.

***Gain on Sale of Assets***

NRG s net gain on sale of assets for the six months ended June 30, 2007 was approximately $16 million. On January 3, 2007, NRG completed the sale of the Company s Red Bluff and Chowchilla II power plants resulting in a pre-tax gain of approximately $18 million.

***Equity in Earnings of Unconsolidated Affiliates***

NRG s equity earnings from unconsolidated affiliates for the six months ended June 30, 2007 decreased by $8 million compared to 2006. This decrease was due to:

- o *Sale of multiple equity investments* equity earnings of $5 million were earned in the six months ended June 30, 2006, from multiple affiliates that were either sold or subsequently consolidated, including: WCP, Rocky Road, James River and Latin American funds.

- o *Other equity investments* earnings from the Company s MIBRAG investment decreased by $5 million due to increased stripping costs during 2007 and the positive impact of new accounting guidance associated with German retirement requirements that was implemented during 2006. Earnings from Gladstone increased by $3 million due to the collection of insurance claims for forced outages that occurred during 2006 and increased generation.

- o *MIBRAG* - On June 22, 2007, Germany enacted the *German National $CO_2$ Allocation Plan 2008 2012*, in which MIBRAG was granted $CO_2$ allocations that are less than the needs of its three generating plants. The financial impact of this regulation on MIBRAG s results is not yet clear and management of MIBRAG is investigating a number of options to minimize any adverse impact.

***Other Income, Net***

NRG s other income for the six months ended June 30, 2007 decreased by $58 million compared to 2006. This decrease was due to:

- o *Non-cash settlement* during the first quarter 2006, NRG recorded approximately $67 million of other income associated with a settlement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001. The settlement resulted in the 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.

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- o *Interest income* increased by approximately $3 million for the six months ended June 30, 2007 compared to 2006 due to higher market interest rates on deposits.

***Interest Expense***

NRG s interest expense for the six months ended June 30, 2007 increased by $89 million compared to 2006. This increase was due to:

- o *Refinancing for the acquisition of Texas Genco LLC in February 2006* - the Company significantly increased its corporate debt facilities from approximately $2 billion as of December 31, 2005, to approximately $7 billion as of February 2, 2006. This increased interest expense by $34 million compared to 2006.

- o *Increase of $1.1 billion in debt for Hedge Reset* the Company issued $1.1 billion in Senior Notes due 2017 in November 2006 related to the Hedge Reset, which increased interest expense by $41 million.

- o *Capital Allocation Program* the Company issued a total of $330 million of debt to fund Phase I of the Capital Allocation Program during the second half of 2006. This increased interest expense by $14 million compared to 2006.

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 six months ended June 30, 2007, NRG had deferred a gain of $14 million in other comprehensive income compared to deferred gains of $74 million in 2006.

***Refinancing Expense***

Refinancing expense decreased by $143 million during the six months ended June 30, 2007, compared to 2006 due to the refinancing of the Company s corporate debt for the acquisition of Texas Genco LLC on February 2, 2006 compared to the refinancing expense related to the Comprehensive Capital Allocation Plan implemented during 2007.

*Comprehensive Capital Allocation Plan* - on June 8, 2007, NRG completed the $4.4 billion refinancing of the Company s Senior Credit Facility previously announced on May 2, 2007. The transaction resulted in a 0.25% reduction on the spread that the Company pays on its term loan and Synthetic Letter of Credit facility, a $200 million reduction in the Synthetic Letter of Credit Facility to $1.3 billion, and various amendments to provide improved flexibility, efficiency for returning capital to shareholders, asset repowering and investment opportunities. The pricing on the Company s term loan and Synthetic Letter of Credit is also subject to further reductions upon the achievement of certain financial ratios. The refinancing resulted in a charge of approximately $35 million to the current period s results of operations that were primarily related to the write-off of deferred financing costs as the lenders for approximately 45% of the Term B loan either exited the financing or reduced their holdings and were replaced by other institutions.

***Income Tax Expense***

Income tax expense increased by $71 million during the six months ended June 30, 2007, compared to 2006. The effective tax rate was 42.3% and 28.4% for the six months ended June 30, 2007 and 2006, respectively. The increase in tax expense was due to increased profits and an increase in permanent differences:

- o *Increased profits* - income before tax increased by $68 million with a corresponding increase of approximately $27 million in tax expense.
- o *Permanent differences*

  *Taxable dividends from foreign subsidiaries* - in January 2007 the Company transferred the proceeds from the sale of its Flinders assets to the U.S. creating additional tax expense of approximately $8 million.

  *Non-deductible interest* interest expense from the stock buybacks from Phase I of the Company s Capital Allocation Program increased tax expense by approximately $5 million.

  *Recognizing losses in foreign jurisdictions during 2006* in certain foreign locations, the Company recognized a benefit of approximately $10 million during the first half of 2006 as compared to 2007.

*Disputed claims reserve* - During the first half of 2006 as compared to 2007, the Company distributed larger payments from its disputed claims reserve that reduced income tax expense by approximately $28 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***

Income from discontinued operations decreased by $12 million during the six months ended June 30, 2007, compared to 2006 as all discontinued operations were disposed of in 2006. During 2006, the Company sold its Audrain, Flinders and Resource Recovery operations that were classified as discontinued operations, with $11 million due to the after tax gain from the sale of Audrain and $1 million due to the aggregated results of their remaining operations for the six month period ended June 30, 2006.

**Business Segment Results**

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 Company s Texas operations, see pages 18-22 of NRG s 2006 Annual Report on Form 10-K.

***Selected income statement data***

| | Three months ended June 30 | | | Six months ended June 30 [b] | | |
|---|---|---|---|---|---|---|
| **(In millions except otherwise noted)** | **2007** | **2006** | **Change %** | **2007** | **2006** | **Change %** |
| **Operating Revenues** | | | | | | |
| Energy revenue | $ 687 | $ 483 | 42 | $ 1,250 | $ 713 | 75 |
| Capacity revenue | 91 | 225 | (60) | 183 | 390 | (53) |
| Risk management activities | 26 | 8 | 225 | 6 | (22) | NA |
| Contract amortization | 61 | 222 | (73) | 108 | 263 | (59) |
| Other revenues | 10 | 3 | 233 | 23 | 3 | 667 |
| Total operating revenues | 875 | 941 | (7) | 1,570 | 1,347 | 17 |
| **Operating Costs and Expenses** | | | | | | |
| Cost of energy | 310 | 342 | (9) | 547 | 560 | (2) |
| Other operating expenses | 166 | 140 | 19 | 352 | 236 | 49 |
| Depreciation and amortization | 114 | 131 | (13) | 228 | 205 | 11 |
| **Operating income** | $ 285 | $ 328 | (13) | $ 443 | $ 346 | 28 |
| MWh sold (in thousands) | 12,265 | 12,742 | (4) | 23,245 | 20,055 | 16 |
| MWh generated (in thousands) | 11,994 | 12,571 | (5) | 22,737 | 19,109 | 19 |
| **Business Metrics** | | | | | | |
| Average on-peak market power prices ($/MWh) | 70.87 | 70.19 | 1 | 64.18 | 63.34 | 1 |
| Cooling Degree Days, or CDDs[a] | 752 | 1,012 | (26) | 854 | 1,109 | (23) |
| CDD s 30 year rolling average | 790 | 777 | 2 | 870 | 843 | 3 |
| Heating Degree Days, or HDDs[a] | 169 | 47 | 260 | 1,372 | 654 | 110 |
| HDD s 30 year rolling average | 112 | 112 | | 1,382 | 789 | 75 |

(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.*

(b) *For the period February 2, 2006 to June 30, 2006.*

***<u>Quarterly Results</u>***

***Operating Income***

For the three months ended June 30, 2007 compared to 2006, operating income decreased by $43 million due to:

o

*Hedge Reset* this increased the Texas region s revenues by approximately $106 million as the period s average price of the underlying power contracts increased by $12 per MWh.

o *Contract Amortization* following the Hedge Reset, contract amortization revenues decreased by $161 million.

o *Fuel Cost* significantly lower gas generation resulted in a corresponding reduction in natural gas cost of $61 million.

o *Outage Impacts* a planned refueling outage at STP led to an $8 million increase in operating expense and outage-associated purchased power increased the cost of energy by $9 million.

o *Development costs* as part of *RepoweringNRG*, development costs totaled $24 million.

***Operating Revenues***

Total operating revenues from the Texas region decreased by $66 million during the three months ended June 30, 2007, as compared to 2006, due to the following:

- o *Energy revenues*  energy revenues increased by $204 million of which $106 million was due to the Hedge Reset as average forward prices for the period increased by approximately $12 per MWh for 2007 compared to 2006. The remaining increase was due to a reduction of the PUCT auctioned capacity that is now being sold in the merchant market. Prior to the Acquisition, PUCT regulations required that Texas sell 15% of its capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG s request to no longer participate in these auctions and that capacity is now being sold in the merchant market.

- o *Capacity revenues*  capacity revenues decreased by $134 million due to the reduction in capacity auction sales mandated by the PUCT in prior years.

- o *Contract amortization* - revenues from contract amortization decreased by $161 million as a result of the Hedge Reset coupled with the fact that in-the-market power contracts acquired with the Texas acquisition were fully amortized in 2006.

- o *Other revenues*  the Company s revenues from ancillary services increased by approximately $7 million due to a change in strategy which increased the Company s participation in the ancillary services market in the Texas region.

*Risk Management Activity*  Total derivative revenues increased by $18 million for the second quarter 2007 as compared to 2006. The derivative gain of $26 million was comprised of a loss on financial revenues of $2 million offset by mark-to-market gains of $28 million. Of these mark-to-market gains, $23 million was due to the roll-off of 2006 mark-to-market gains and $51 million was related to open positions on forward hedges  a $76 million gain from forward electric and gas sales partially offset by a $28 million loss in cash flow hedge ineffectiveness due to a change in the correlation between natural gas and power prices and a $3 million gain from trading activities.

***Cost of Energy***

Cost of energy for the Texas region decreased by $32 million during the three months ended June 30, 2007, compared to 2006, due to the following:

- o *Purchased power*  increased by $13 million due to forced outages at the region s Parish and Limestone plants in 2007.

- o *Natural gas costs*  decreased by approximately $61 million due to a 38% decrease in gas-fired generation largely because of milder weather and increased economic purchases from ERCOT.

- o *Purchased ancillary service expense*  increased by $9 million due to the favorable market price in purchasing this service in the market as opposed to providing the service from internal resources.

- o *Coal expense*  increased by $8 million due to higher generation.

***Other Operating Expenses***

Other operating expenses for the Texas region increased by $26 million during the three months ended June 30, 2007 compared to 2006. This was due to:

- o *Planned outages*  O & M expense increased by $8 million due to the planned refueling outage at STP.

- o *Development costs*  as part of *RepoweringNRG*, development costs totaled $24 million in the second quarter 2007. Of this amount, $23 million was incurred for developing nuclear units 3 and 4 at STP.

***Year-to-date Results***

***Operating Income***

For the six months ended June 30, 2007, operating income increased by $97 million as compared to 2006. Of this increase, $67 million was due to the January 2007 results on 4.2 million MWh of generation.

- o *Hedge Reset* - for the first half of 2007, the Hedge Reset increased the region s revenues by approximately $145 million as compared to 2006 as the period s average price of the underlying power contracts increased by

$10 per MWh.

- *Outage Impacts* decreased forced outages in 2007 as compared to the same period last year led to an $11 million increase in operating income.

- *Development costs* as part of *RepoweringNRG*, development costs totaled $42 million in the first half of 2007. Of this amount, $39 million was incurred for developing nuclear units 3 and 4 at STP.

***Operating Revenues***

Total operating revenues from the Texas region increased by $223 million during the six months ended June 30, 2007, as compared to 2006, due to the following:

- *Energy revenues* energy revenues increased by $537 million of which $217 million was due to the inclusion of six months activity in 2007 compared to five months in 2006, and $145 million is due to the Hedge Reset as the period s average forward prices increased by approximately $10 per MWh for 2007 compared to 2006. The remaining increase was due to a reduction of PUCT auctioned capacity that is now being sold under long-term bilateral agreements in the merchant market. Prior to the Acquisition, PUCT regulations required that Texas sell 15% of its capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG s request to no longer participate in these auctions.

- *Capacity revenues* capacity revenues decreased by $207 million due to the inclusion of six months activity in 2007 compared to five months in 2006 of $31 million and a reduction of capacity auction sales mandated by the PUCT in prior years as described above.

- *Contract amortization* revenues from contract amortization decreased by $155 million as a result of in-the-market power contracts acquired with the Texas acquisition that were fully amortized in 2006 and the write off of out-of-market contract revenue during the fourth quarter of 2006 related to the Hedge Reset.

- *Other revenues* the Company s revenues from ancillary services increased by approximately $20 million due to a change in strategy to actively provide ancillary services in the Texas region.

*Risk Management Activity* Total derivative gain for the first half of 2007 increased by $28 million as compared to 2006. The derivative gain of $6 million is comprised of financial revenues of $16 million offset by mark-to-market losses of $10 million. Of these mark-to-market losses, $53 million was due to the roll-off of 2006 mark-to-market gains and $43 million was related to open positions on forward hedges a $23 million gain from forward electric and gas sales and a $15 million gain in cash flow hedge ineffectiveness due to a change in the correlation between natural gas and power prices.

***Cost of Energy***

Cost of energy for the Texas region decreased by $13 million during the six months ended June 30, 2007, compared to 2006. This included an additional month s expense of $96 million in 2007, without which cost of energy would have decreased by $109 million. This was due to:

- *Gas expense* decreased by $82 million due to the decrease of 1 million MWh during the period due to milder weather coupled with greater economic purchases from ERCOT and increased baseload generation.

- *Purchased power* decreased by $27 million due to forced outages in 2006 at the region s Parish and Limestone plants.

- *Amortized fuel costs* decreased by approximately $16 million due to the fuel price curves being below the contracted prices at acquisition in February 2006.

- *Purchased ancillary service expense* increased by approximately $15 million due to the favorable market price in purchasing this service in the market as opposed to providing the service from internal resources.

***Other Operating Expenses***

Other operating expenses for the Texas region increased by $116 million during the six months ended June 30, 2007 compared to 2006. This was due to:

- *Texas acquisition* - the inclusion of Texas results for six months in 2007 compared to five months in 2006 that resulted in an increase of approximately $53 million, of which $32 million was related to operating and maintenance costs, $6 million was property taxes and $15 million was related to general and administrative expenses and corporate allocations.

- *Increase in operations and maintenance, or O&M, expense* O&M expense increased by $45 million, of which $32 million was related to January 2007. The remaining difference is due to the Spring 2007 STP refueling outage that cost $16 million and $7 million of increased maintenance expense at the gas plants. These increases were offset by $10 million lower maintenance costs at the coal-fired plants because of reduced planned outage time in 2007.

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- o *Development costs* as part of *RepoweringNRG*, development costs totaled $42 million in the first half of 2007, of which $39 million was related to developing nuclear units 3 and 4 at STP.

- o *Higher corporate allocations* - of approximately $5 million

**Northeast Region**

For a discussion of the business profile of the Northeast region, see pages 22-25 of NRG s. 2006 Annual Report on Form 10-K.

***Selected income statement data***

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| **(In millions except otherwise noted)** | **2007** | **2006** | **Change %** | **2007** | **2006** | **Change %** |
| **Operating Revenues** | | | | | | |
| Energy revenue | $ 254 | $ 198 | 28 | $ 526 | $ 421 | 25 |
| Capacity revenue | 93 | 91 | 2 | 176 | 149 | 18 |
| Risk management activities | 24 | 6 | 300 | (5) | 55 | NA |
| Other revenues | 24 | 8 | 200 | 40 | 93 | (57) |
| Total operating revenues | 395 | 303 | 30 | 737 | 718 | 3 |
| **Operating Costs and Expenses** | | | | | | |
| Cost of energy | 145 | 123 | 18 | 307 | 272 | 13 |
| Other operating expenses | 103 | 92 | 12 | 206 | 185 | 11 |
| Depreciation and amortization | 24 | 22 | 9 | 49 | 44 | 11 |
| **Operating income** | $ 123 | $ 66 | 86 | $ 175 | $ 217 | (19) |
| MWh sold (in thousands) | 3,073 | 2,820 | 9 | 6,696 | 6,081 | 10 |
| MWh generated (in thousands) | 3,073 | 2,820 | 9 | 6,696 | 6,081 | 10 |
| **Business Metrics** | | | | | | |
| Average on-peak market power prices ($/MWh) | 75.33 | 65.10 | 16 | 74.62 | 66.79 | 12 |
| Cooling Degree Days, or CDDs(a) | 161 | 140 | 15 | 161 | 140 | 15 |
| CDD s 30 year rolling average | 112 | 105 | 7 | 112 | 105 | 7 |
| Heating Degree Days, or HDDs(a) | 830 | 716 | 16 | 3,901 | 3,457 | 13 |
| HDD s 30 year rolling average | 841 | 841 | | 3,935 | | |