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

FORM 10-Q

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

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

For the quarterly period ended: **June 30, 2007**

Commission File Number: **001-15891**

NRG Energy, Inc.

(Exact name of Registrant as specified in its charter)

Delaware

(State or other jurisdiction
of incorporation or organization)

41-1724239

(I.R.S. Employer
Identification No.)

211 Carnegie Center

Princeton, New Jersey

(Address of principal executive offices)

08540

(Zip Code)

(609) 524-4500

(Registrant's telephone number, including area code)

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

Yes No

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

Large accelerated filer Accelerated filer Non-accelerated filer

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

Yes No

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

Yes No

As of 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”, “expects”, “intends”, “estimates” and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause NRG Energy Inc’s, 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 *Repowering NRG* 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.

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
LFMR	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
<i>RepoweringNRG</i>	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

Part I — FINANCIAL INFORMATION

Item 1 — Condensed Consolidated Financial Statements and Notes

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

(In millions, except for per share amounts)	Three months ended June 30		Six months ended June 30	
	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.

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.

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

(In millions)	2007	2006
Six months ended June 30,		
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)

(In millions)	Three months ended June 30		Six months ended June 30	
	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 Dynege, Inc. Under the agreements, NRG acquired Dynege'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 Dynege 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 Dynege 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:

(In millions)	Original Investment	New Investment		Purchase Price Allocation	
		Fair Value before Negative Goodwill Allocation	Allocation of Negative Goodwill		Fair Value after Negative Goodwill 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:

(In millions)	Three months ended June 30		Six months ended June 30	
	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.

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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

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- 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.

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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*:

[Table of Contents](#)*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:

(In millions, except per share data)	Three months ended June 30		Six months ended June 30	
	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 method)	37.5	41.6	21.0	37.8
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:

(In millions)	Three months ended June 30		Six months ended June 30	
	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)	Wholesale Power Generation								
	Three months ended June 30, 2007	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination
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)	Wholesale Power Generation								
	Three months ended June 30, 2006	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination
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)	Wholesale Power Generation								
	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Six months ended June 30, 2007									
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)	Wholesale Power Generation								
	Texas (a)	Northeast	South Central	West (b)	International	Thermal	Corporate	Elimination	Total
Six months ended June 30, 2006									
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.

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:

(In millions except rate data)	Six months ended June 30	
	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

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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:

(In millions)	Defined Benefit Pension Plans			
	Three months ended June 30,		Six months ended June 30,	
	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:

(In millions)	Other Postretirement Benefits Plans			
	Three months ended June 30,		Six months ended June 30,	
	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.

Repowering NRG Project Deposits

NRG has made non-refundable deposits totaling approximately \$15 million towards the procurement of equipment related to *Repowering NRG* 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

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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

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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, SO₂, 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 SO₂, 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 SO₂ 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.

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Each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of June 30, 2007:

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

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

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the 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.

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					
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.

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					
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.

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.

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.

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					
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.

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					
Income tax expense/(benefit)	607	125	38	(467)	303
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.

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.

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
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	3	—	—	3
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.*

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 *FORNRG*, 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. ***FORNRG*** 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.

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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.

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:

(In millions except otherwise noted)	Three months ended June 30,			Six months ended June 30,		
	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 *Repowering NRG* 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

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:

- o *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.
- o *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.
- o *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.
- o *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 SO2 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:

(In millions)	Three months ended June 30, 2007				Three months ended June 30, 2006				
	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:

- o *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.
- o *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:

- 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 \$20 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, 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

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- 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 SO2 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:

(In millions)	Six months ended June 30, 2007				Six months ended June 30, 2006				
	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:

- 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 \$38 million that was offset by higher depreciation estimates of approximately \$15 million during 2006 as compared to 2007.
- o *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 CO₂ Allocation Plan 2008 – 2012*, in which MIBRAG was granted CO₂ 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

(In millions except otherwise noted)	Three months ended June 30			Six months ended June 30 (b)		
	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.

Quarterly Results

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 *Repowering NRG*, 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:

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- 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 \$5 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 *Repowering NRG*, 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.
- o *Outage Impacts* – decreased forced outages in 2007 as compared to the same period last year led to an \$11 million increase in operating income.

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- o *Development costs* – as part of *Repowering NRG*, 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:

- o *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.
- o *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.
- o *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.
- o *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:

- o *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.
- o *Purchased power* – decreased by \$27 million due to forced outages in 2006 at the region's Parish and Limestone plants.
- o *Amortized fuel costs* – decreased by approximately \$16 million due to the fuel price curves being below the contracted prices at acquisition in February 2006.
- o *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:

- o *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.
- o *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 *Repowering NRG*, 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

(In millions except otherwise noted)	Three months ended June 30,			Six months ended June 30,		
	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	3,935	—

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

Quarterly Results

Operating Income

Operating income increased by \$57 million for the three months ended June 30, 2007, as compared to 2006. This was due to:

- o *Operating revenues* – increased by approximately \$92 million due to both increased generation and higher power prices that ultimately increased energy revenues by \$56 million, higher risk management results of \$18 million and a \$10 million increase in sales of emission allowances.
- o *Offset by cost of energy* - increased by approximately \$22 million due to increased generation at the region's natural gas-fired plants in New York City.
- o *Other operating expenses* - increased by approximately \$11 million due to prior year benefit of \$18 million related to a favorable station service court decision during 2006, offset by lower maintenance costs of \$5 million and lower property tax of \$5 million.

Operating Revenues

Operating revenues increased by \$92 million for the three months ended June 30, 2007, as compared to 2006, due to:

- o *Energy revenues* – increased by \$56 million of which \$17 million was due to a 9% increase in generation led by the region's gas fired Arthur Kill plant whose generation increased by 226 thousand MWh and \$36 million was due to a 16% increase in average market prices. These increases were due to increasing natural gas prices which drove increases in

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average prices in the region's primary market, coupled with the effect of transmission constraints in the New York City area which also allowed the dispatch of our Arthur Kill plant.

- o *Capacity revenues* – increased by \$2 million – this was due to increased capacity in NEPOOL from LFRM of \$9 million and transition payments of \$6 million, offset by the loss of \$13 million primarily from the Devon RMR capacity agreement as of December 31 2006. Increased capacity revenues from PJM from the new RPM market of \$5 million were offset by lower capacity revenues in New York as we realized capacity prices that were lower than those attained during 2006.
- o *Risk management activities* – of approximately \$24 million during 2007 compared to \$6 million in gains in 2006. The \$24 million gain includes a \$17 million unrealized gain related to the changes in fair value of forward derivative positions not qualifying for hedge accounting treatment as compared to a gain of the same amount in the same period in 2006. Risk management revenues also includes the value of settled power positions of \$7 million gain for the 2007 quarter compared to a \$11 million loss in 2006. The \$18 million increase is driven largely by favorable energy trading by \$8 million combined with an increase in option premium revenues of \$8 million.
- o *Other revenues* – increased by \$16 million of which approximately \$10 million was due to increased sales of emission credits together with a \$6 million increase in inter-company natural gas sales.

Cost of Energy

Cost of energy increased by \$22 million for the three months ended June 30, 2007 as compared to 2006, primarily due to higher natural gas costs of approximately \$27 million due to increased generation from the region's New York City plants, offset by lower fuel oil costs of approximately \$5 million due to the reduction in generation from the region's oil-fired assets, particularly in NEPOOL.

Other Operating Expenses

Other operating expenses increased by \$11 million for the three months ended June 30, 2007 as compared to 2006, due to higher utilities and auxiliary powers of approximately \$18 million following the reversal of an \$18 million accrual during 2006 after the favorable court decision related to station service obligations at the region's Western New York plants. This was partially offset by:

- o *Maintenance expense* – decreased by approximately \$3 million due to fewer outage repairs.
- o *Property tax* - decreased by approximately \$5 million as prior year results included a \$5 million reduction in property tax credits following a change in the tax law during 2006.

Year-to-date Results

Operating Income

Operating income decreased by \$42 million for the six months ended June 30, 2007, compared to 2006. This was due to:

- o *Cost of energy* - increased by approximately \$35 million due to increased generation at the region's oil- and natural gas-fired plants in New York City.
- o *Other operating expenses* – increased by \$21 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
- o *Offset by higher operating revenues* – of approximately \$19 million due to increased generation and favorable pricing, the favorable impact from new capacity markets, partially offset by losses in the region's risk management activities and lower sales of emission allowances due to the 43% reduction in market prices.

Operating Revenues

Operating revenues increased by \$19 million for the six months ended June 30, 2007, compared to 2006, due to:

- o *Energy revenues* – increased by approximately \$105 million due to \$43 million from 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 of 2007 compared to 2006, of which 194 thousand MWh was from the region's Arthur Kill plant due to transmission constraints around New York City, the region's Oswego plant whose

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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 region's NEPOOL assets due to an extended outage of a baseload plant in the region and a colder winter.

- *Price* - On average, prices in the Northeast increased by 12% due to a 15% increase in natural gas prices during the second quarter and following transmission constraints in New York City that led to price increases of approximately 17% in the area.
- o *Capacity revenues* – increased by \$27 million — \$13 million of the increase was from the region's NEPOOL assets, \$9 million was from New York Rest of State assets and \$5 million was from the region's PJM assets.
 - *NEPOOL* – The region's NEPOOL assets benefited from the new LFRM market and transition capacity market, both introduced in the fourth quarter 2006. Capacity revenues increased by \$17 million from the LFRM market and \$13 million from transition capacity payments, offset by a reduction of \$17 million due primarily to the expiration of an RMR agreement for the region's Devon plant on December 31, 2006.
 - *NYISO* – New York Rest of State capacity prices increased by 109% 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.
 - *PJM* – 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.

These were partially offset by:

- o *Losses related to risk management activities* – losses of approximately \$5 million during 2007 compared to \$55 million in gains in 2006. The \$5 million loss includes a \$41 million unrealized loss related to the changes in fair value of forward derivative positions not qualifying for hedge accounting treatment as compared to a \$67 million gain in the same period in 2006. Risk management activities also include the value of settled power positions of \$36 million gain for the first half of the year 2007 compared to a \$12 million loss in 2006. The \$48 million increase is driven largely by favorable gas trading of \$27 million combined with an increase in option premium revenues of \$18 million..
- o *Reduction in other revenues* – of approximately \$53 million of which approximately \$51 million was due to reduced activity in the trading of emission allowance following both an increase in generation and a 43% decrease in market prices..

Cost of Energy

Cost of energy increased by \$35 million for the six months ended June 30, 2007 compared to 2006, due to:

- o *Oil costs* - increased by approximately \$28 million 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.
- o *Natural gas costs* - increased by approximately \$19 million following increased generation at the region's Arthur Kill plant due to its locational advantage to New York City following transmission constraints during the second quarter 2007.

These were partially offset by:

- o *Emission allowance amortization* - decreased by approximately \$9 million in amortization expense due to a reduction in the value of the Company's emission allowances.
- o *Coal costs* - despite increased generation of 126 thousand MWh at the region's coal-fired plants, coal costs decreased by \$4 million due to a lower average cost of generation from the region's coal-fired assets as a result of lower average prices of purchased coal. This reduction in price was favorably impacted by an extended outage at the Company's Indian River plant which avoided the consumption of higher cost coal.

Other Operating Expenses

Other operating expenses increased by \$21 million for the six months ended June 30, 2007 compared to 2006, due to:

- o *Favorable station service court decision in 2006* – during 2006, the Company reversed an \$18 million accrual following the favorable court decision related to station service obligations at the region's Western New York plants.
- o *Development costs* – as part of *Repowering NRG*, development costs totaled \$4 million in the first half of 2007 primarily on the Company's New York IGCC project. These were partially offset by:

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- o *Favorable property tax* – of approximately \$5 million due to a tax law change in 2006 that resulted in the reduction of a property tax receivable of \$5 million in 2006.

South Central Region

For a discussion of the business profile of the South Central region, see pages 26-27 of NRG's 2006 Annual Report on Form 10-K.

Selected income statement data

(In millions except otherwise noted)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	Change %	2007	2006	Change %
Operating Revenues						
Energy revenue	\$ 101	\$ 72	40	\$ 188	\$ 150	25
Capacity revenue	54	49	10	107	97	10
Risk management activities	2	(1)	NA	8	4	100
Contract amortization	6	4	50	11	8	38
Other revenues	—	1	NA	—	7	NA
Total operating revenues	163	125	30	314	266	18
Operating Costs and Expenses						
Cost of energy	105	81	30	186	140	33
Other operating expenses	32	27	19	62	49	27
Depreciation and amortization	17	18	(6)	34	34	—
Operating income/(loss)	\$ 9	\$ (1)	NA	\$ 32	\$ 43	(26)
MWh sold (in thousands)	3,004	2,810	7	5,831	5,593	4
MWh generated (in thousands)	2,515	2,429	4	5,223	5,229	—
Business Metrics						
Average on-peak market power prices (\$/MWh)	64.13	57.13	12	60.99	55.62	10
Cooling Degree Days, or CDDs ^(a)	752	1,012	(26)	854	1,126	(24)
CDD's 30 year rolling average	790	777	2	870	857	2
Heating Degree Days, or HDDs ^(a)	169	47	260	1,372	993	38
HDD's 30 year rolling average	112	112	—	1,382	1,382	—

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

Quarterly Results

Operating Income

Operating income for the South Central region increased by \$10 million for the second quarter 2007 compared to the same period in 2006. The increase was driven by a new contract with a local utility, higher Co-op billing peaks, and favorable tolling agreements to support load, offset by increased scope of maintenance work and higher coal costs. Although MWh sold increased by 7% the potential increase to operating income was eliminated due to an average increase to the cost per MMBtu of \$0.16 as higher fuel charges and new contract rates negatively impacted the South Central region. Maintenance expenses increased by \$5 million at the region's Big Cajun II facility due to planned outages as the scope of work was larger during 2007 as compared to 2006.

Operating Revenues

Operating revenues increased \$38 million for the three months ended June 30, 2007, compared to 2006, due to:

- o *Energy revenue* – increased by \$29 million of which \$21 million was due to a new contract with a local utility, and an additional \$3 million was due to increased Co-op contract prices driven by the updated pass-through of actual fuel costs.
- o *Capacity revenue* – increased by \$5 million due to the billing peak set by the Co-op customers in 2006, capacity payments from the new contract with the local utility, and a favorable merchant capacity market for the region's Rockford facilities.

Cost of Energy

Cost of energy increased by \$24 million for the three months ended June 30, 2007, compared to 2006:

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- o *Purchased power* – the region relied more heavily on tolling agreements to support contract load requirements and merchant sales during the second quarter 2007 as compared to 2006.
- o *Coal and transportation costs* – increased by approximately \$5 million and higher transmission costs of approximately \$4 million. These increases were due to higher unit and contractual rate increases.

Other Operating Expenses

Other operating expenses increased by \$5 million for the three months ended June 30, 2007, compared to 2006. Major maintenance expense increased by \$5 million due to the increased scope of the Big Cajun II, Unit 1 outage and the hanger replacement project. G&A decreased by \$1 million despite an increase in franchise tax expense as this was offset by lower development costs and lower insurance expense.

Year-to-date Results

Operating Income

Operating income for the South Central region declined by \$11 million for the six months ended June 30, 2007 compared to 2006, primarily due to increased scope of maintenance work and increased state franchise tax. Although MWh sold increased by 4%, the potential increase to operating income was eliminated due to an average increase to the cost per MMBtu of \$0.25 as higher fuel charges and new contract rates negatively impacted the South Central region. Maintenance expenses at the region's Big Cajun II facility due to planned outages increased by approximately \$6 million as the scope of work was larger during 2007 as compared to 2006. Louisiana state franchise tax increased by approximately \$7 million because this franchise tax is assessed based on the Company's total debt and equity that increased significantly following the acquisition of Texas Genco LLC.

Operating Revenues

Operating revenues increased by \$48 million for the six months ended June 30, 2007, compared to 2006, due to:

- o *Contract energy revenues* – increased by \$40 million due to new annual contracts and a 6% increase in Co-op contract prices driven by the updated pass-through of actual fuel costs.
- o *Capacity revenues* – increased by \$10 million, of which \$7 million was due to increased demand during 2006 which in turn increased billed capacity volumes by 482 thousand KW during 2007. The region's Rockford facilities added an additional \$2 million in capacity revenue.

This increase was offset by:

- o *Merchant energy revenues* – decreased by \$1 million due to reduced sales into the Entergy market following transmission constraints, and increased outage hours.
- o *Emission sales* – decreased by \$8 million due to reduced activity in the trading of emission allowance following a 43% decrease in market prices.

Cost of Energy

Cost of energy increased by \$46 million for the six months ended June 30, 2007, compared to 2006, due to:

- o *Purchased power* – increased by approximately \$29 million primarily from increased reliance on tolling agreements and increased market purchases due to planned maintenance.
- o *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.
- o *Transmission expense* – transmission constraints in SERC Entergy led to an increase in off-system purchases and sales which resulted in an increase in transmission-related expenses of approximately \$8 million.

Other Operating Expenses

Other operating expenses increased by \$13 million for the six months ended June 30, 2007, compared to 2006 due to increased maintenance costs and an increase in Louisiana state franchise tax. Maintenance expenses at the region's Big Cajun II facility due to planned outages increased by approximately \$6 million as the scope of work was larger during 2007 as compared to 2006. Louisiana state franchise tax increased by approximately \$7 million because this franchise tax is assessed based on the Company's total debt and equity that increased significantly following the acquisition of Texas Genco LLC.

West Region

For a discussion of the business profile of the West region, see pages 28-29 of NRG's 2006 Annual Report on Form 10-K.

Selected income statement data

(In millions except otherwise noted)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	Change %	2007	2006	Change
Operating Revenues						
Energy revenue	\$ —	\$ 27	NA	\$ 1	\$ 27	(96)
Capacity revenue	29	20	45	55	20	175
Risk management activities	—	(1)	NA	—	(1)	NA
Other revenues	—	3	NA	1	4	(75)
Total operating revenues	29	49	(41)	57	50	14
Operating Costs and Expenses						
Cost of energy	—	26	NA	1	26	(96)
Other operating expenses	19	15	27	39	18	117
Depreciation and amortization	1	1	—	1	1	—
Operating income	\$ 9	\$ 7	29	\$ 16	\$ 5	220
MWh sold (in thousands)	108	400	(73)	147	694	(79)
MWh generated (in thousands)	108	400	(73)	147	694	(79)
Business Metrics						
Average on-peak market power prices (\$/MWh)	68.86	54.14	27	64.46	56.01	15
Cooling Degree Days, or CDDs ^(a)	135	240	(44)	137	240	(43)
CDD's 30 year rolling average	171	150	14	181	157	15
Heating Degree Days, or HDDs ^(a)	607	444	37	2,193	1,878	17
HDD's 30 year rolling average	556	556	—	1,975	1,975	—

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

Quarterly Results

Operating Income

Operating income increased by \$2 million for the three months ended June 30, 2007, compared to 2006, due to:

- o *New tolling agreements* – the new tolling agreements at the region's Encina and El Segundo plants contributed \$5 million to operating income as compared to the prior year's RMR agreement at our Encina facility and the El Segundo toll which started May 1, 2006.
- o *Derivative revenue* – during 2006, fuel hedges covering the Company's investment in Saguaro reduced revenues by \$1 million.

This increase was offset by:

- o *Operating expenses* – increased by approximately \$4 million due to increased maintenance work at the Encina and El Segundo facilities to ensure availability per the new tolling agreements partially offset by a decrease in corporate allocations.

Year-to-date Results

Operating Income

Operating income increased by \$11 million for the six months ended June 30, 2007, compared to 2006, due to:

- o *Consolidation since March 31, 2006* – operating income increased by \$11 million due to the consolidation of WCP’s results following the acquisition of Dynegy’s 50% interest.
- o *New tolling agreements* – operating income increased by \$5 million due to the new tolling agreements at the region’s Encina and El Segundo plants as compared to the prior year’s RMR agreement at our Encina facility and the El Segundo toll which started May 1, 2006.
- o *Derivative revenue* – during 2006, fuel hedges covering the Company’s investment in Saguaro reduced revenues by \$1 million.
- o *Emission credit revenue* – sold excess emission credits with a gain of approximately \$1 million.

This increase was offset by:

- o *Major maintenance costs* – increased by approximately \$3 million for increased maintenance work at the Encina and El Segundo facilities to ensure availability per the new tolling agreements.
- o *Development costs* – as part of *Repowering NRG*, development costs totaled \$3 million in the first half of 2007 related to the El Segundo II project and other initiatives in the region.
- o *G&A costs* – increased by \$2 million due to increased labor costs to support the acquired WCP assets and an increase in Corporate allocations.

Liquidity and Capital Resources

Liquidity Position

As of June 30, 2007, NRG's liquidity was approximately \$1.9 billion and included approximately \$847 million of unrestricted and restricted cash. NRG's liquidity also included \$929 million of borrowing capacity under the Company's Revolving Credit Facility, and \$78 million of availability under the Company's Synthetic Letter of Credit Facility. As of December 31, 2006, NRG's liquidity was approximately \$2.2 billion and included approximately \$839 million of unrestricted and restricted cash. NRG's liquidity also included \$855 million of borrowing capacity under the Company's Revolving Credit Facility, and \$533 million of availability under the Company's Synthetic Letter of Credit Facility.

Management believes that these amounts and cash flows from operations will be adequate to finance capital expenditures, to fund dividends to NRG's preferred shareholders and other liquidity commitments. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activity in a manner consistent with its intention to maintain a steady debt to capital ratio in the range of 45-60%.

Comprehensive Capital Allocation Plan

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 and increase common share repurchases in 2008 from previously stated targets.

During the first half of 2007, NRG repurchased 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.

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 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 may 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 and July 25, 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 and \$58 million, respectively.

The following table summarizes the amount of MWs hedged against the Company's baseload assets and as a percentage relative to the Company's forecasted baseload capacity under the second lien structure as of July 25, 2007:

Equivalent Net Sales secured by Second Lien Structure^(a)	2007^(b)	2008	2009	2010	2011	2012
In MW	3,579	3,673	3,704	2,978	3,189	566
As a percentage of total forecasted baseload capacity	59%	62%	63%	51%	55%	11%

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

(b) 2007 MW value consists of August through December positions only.

Capital Expenditures

The following table summarizes NRG's capital expenditure forecast relating to maintenance and environmental projects, by region, for the full year 2007 of approximately \$350 million, inclusive of the \$128 million spent during the first half of 2007:

(In millions)	Maintenance	Environmental	Total
Northeast	\$ 17	\$ 18	\$ 35
Texas	78	—	78
South Central	4	—	4
West	1	—	1
Thermal	9	—	9
Capital expenditures through June 30, 2007	\$ 109	\$ 18	\$ 127
Capital expenditures through the remainder of 2007	121	102	223
Total capital expenditures for 2007	\$ 230	\$ 120	\$ 350

- o *Texas* – capital expenditures in the Texas region were approximately \$78 million due to:
 - *STP* - \$45 million related to nuclear fuel and maintenance
 - *Fossil plants* – \$33 million was spent on low pressure turbine rotor replacement at the W.A Parish and Limestone facilities, combustion system replacement at T.H. Wharton and San Jacinto plants and work related to the Jewett mine.
- o *Northeast* – capital expenditures in the Northeast region were approximately \$36 million due to:
 - *Huntley and Dunkirk* – approximately \$16 million was related to bag house emission project at these two facilities.

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- *Other Northeast facilities* – general plant improvements

NRG anticipates funding these capital projects primarily with funds generated from operating activities. We are also pursuing funding for certain environmental expenditures in the Northeast through Solid Waste Disposal Bonds utilizing tax exempt financing. We only expect to draw upon such funds during 2008.

Repowering NRG Project Deposits

NRG has made non-refundable deposits totaling approximately \$15 million towards the procurement of equipment related to *Repowering NRG* initiatives. The Company believes that these deposits are necessary for the timely and successful execution of these projects. The deposits are in support of expected deliveries of wind turbines and other equipment totaling approximately \$428 million through 2009. Although NRG is committed to the successful implementation of these projects, the Company may decide not to take delivery of the equipment and thus terminate the project. This would result in the Company expensing the deposit it already has made.

NOL's and Other Tax Discussions

As of June 30, 2007, the Company had U.S. domestic net operating loss carryforwards of \$90 million. In addition to this amount, the Company had \$712 million of tax effected unrecognized tax benefits which relate primarily to net operating losses for tax return purposes which have been classified as capital loss carryforwards for financial statements purposes for which a full valuation allowance has been established. As a result of the Company's tax position, and based on current forecasts, future U.S. domestic income tax payments will be minimal through mid year 2009 as these unrecognized tax benefits will be utilized for tax return purposes.

However, as these positions remain uncertain, the Company may recognize a non-current liability of up to \$712 million until resolution with the related taxing authorities. The Company will continue to accrue for such uncertain tax benefits with regular income tax payments that will be contingent upon their final resolution.

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. The change in this net deferred tax liability due to the rate change would be recognized as a tax benefit during the third quarter 2007 and will increase net income by approximately \$28 million.

Cash Flow Discussion

(In millions)	Six months ended June 30,	
	2007	2006
Net cash provided by operating activities	\$ 459	\$ 677
Net cash used in investing activities	(172)	(4,292)
Net cash provided/(used) by financing activities	\$ (291)	\$ 4,075

Net Cash Provided By Operating Activities

For the six months ended June 30, 2007, net cash provided by operating activities decreased by \$218 million compared to the same period in 2006. This was due to:

- Following an upward shift of the forward price curves, NRG's net collateral deposits in support of derivative contracts increased by \$103 million during the six months ended June 30, 2007, compared to a decrease of \$272 million during the same period of 2006, a difference of \$375 million. As of June 30, 2007, NRG had a net cash collateral on deposit of \$49 million;
- Due to the 2006 redemption of NRG's previous senior notes, a premium of \$126 million was paid to NRG's former debt holders;
- NRG's activity for the period resulted in a decrease of \$153 million in cash flows from working capital compared to an increase of \$114 million for the same period in 2006, a difference of \$267 million. This was due to:
 - o The change in accounts receivable reduced cash flows from working capital by \$186 million due to –
 - increase in billable revenues of approximately \$59 million due to the Hedge Reset transaction in November 2006 which increased the second quarter 2007 prices on energy revenues by \$12 per MWh.

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- in March 2006, the PUCT accepted NRG's request to no longer participate in auctions mandating the sale of 15% of generation at reduced rates. Accounts receivable increased during the first half of 2007 as compared to 2006 following this reduction of the PUCT auctioned capacity, as it is now being sold in the merchant market at higher prices by approximately \$52 million.
 - with \$31 million due to the receipt of trade receivables related to sales prior to the purchase of Texas Genco LLC, which was excluded from working capital as they were included as part of the purchase price.
 - the balance for the increase in account receivable was due to a 16% increase in energy prices.
- o An increase of \$24 million in pension funding due to the Company's decision to increase its pension contribution in 2007.

Net Cash Used By Investing Activities

For the six months ended June 30, 2007, net cash used in investing activities was approximately \$4.1 billion less than the same period in 2006. This reduction in investing activities was due to:

- *Texas and WCP acquisitions* – that occurred during the first quarter 2006, NRG acquired Texas Genco LLC for approximately \$6.2 billion that included the issuance of stock at a value of \$1.7 billion and a net cash payment of approximately \$4.3 billion;
- *Capital expenditures* - NRG's capital expenditures increased by \$131 million due to expenditures of approximately \$78 million for *Repowering NRG* projects, primarily Long Beach in the West, and due to \$45 million spent on nuclear fuel and capitalized improvements at the STP plant.

Net Cash Provided/(Used) in Financing Activities

For the six months ended June 30, 2007, net cash used by financing activities decreased by approximately \$4.4 billion as compared to 2006 due to:

- During the first quarter 2006, NRG acquired Texas Genco LLC. As part of the acquisition, NRG refinanced the Company's outstanding debt as well as Texas Genco LLC's outstanding debt, and also issued new debt, preferred stock and common stock to fund the acquisition:
 - o Total debt repayments were \$4.6 billion — \$1.9 billion from NRG debt and \$2.7 billion of Texas Genco LLC debt;
 - o Total proceeds from debt issued was \$7.2 billion — \$3.6 billion of unsecured notes and \$3.6 billion for a senior secured facility, including a \$1.0 billion Revolving Credit Facility, and a \$1.0 billion synthetic Letter of Credit Facility;
 - o Total proceeds from stock issued of approximately \$1.5 billion — net proceeds of \$986 million from issuing approximately 21 million shares of common stock and net proceeds of \$486 million from issuing 2 million shares of the Company's 5.75% Preferred Stock.
- During the six months ended June 30, 2007, NRG repurchased an additional 5,669,200 shares of the Company's common stock for approximately \$215 million as part of the Capital Allocation Program.

New and On-going Company Initiatives

RepoweringNRG Update

Long Beach

On August 1, 2007, the Company successfully completed and commissioned the repowering of 260 MW of new gas-fueled generating capacity at its Long Beach Generating Station. This new generation will provide needed support for the summer peak demand on the Southern California Edison, or SCE, and California Independent System Operator systems. This project is backed by a 10-year power purchase agreement executed with SCE in November 2006. Total capital spending for the project was approximately \$75 million.

Cedar Bayou Generating Station

NRG Texas Power LLC and EnergyCo, LLC (a joint venture between PNM Resources Inc. and a subsidiary of Cascade Investment, L.L.C.) have entered into a Joint Ownership Agreement dated June 26, 2007. Pursuant to this agreement, NRG Cedar Bayou Development Company (a newly formed subsidiary of NRG Energy, Inc.) and EnergyCo Cedar Bayou 4, LLC (a newly formed subsidiary of EnergyCo, LLC) will jointly develop and construct a new 550 MW combined cycle natural gas turbine generating plant at NRG's Cedar Bayou Generating Station in Chambers County, Texas. NRG currently operates two existing units at Cedar Bayou, and a third unit has been in long-term mothball status since 2005.

Pursuant to the terms of the agreement, EnergyCo will pay NRG \$45 million for 50% undivided interest in the proposed plant site and rights to plant equipment already owned by NRG. Going forward, the parties will share equally the obligations to fund plant construction and purchase of additional equipment. Pursuant to the agreement, NRG will provide various services related to construction management and plant operations and maintenance in return for a fixed fee plus reimbursement of its costs.

The Texas Commission on Environmental Air Quality, or TCEQ, granted the air permit required for construction and operation of this new plant on July 26, 2007. On August 1, 2007, NRG Cedar Bayou Development Company and EnergyCo Cedar Bayou 4, LLC have entered in to an Engineering, Procurement and Construction Agreement with Zachry Construction Corp. to construct the plant that is expected to be completed within 24 months.

Wind Power Projects

The Company is working through its Padoma Wind power subsidiary and has reached a stage of advanced development with respect to three wind projects, totaling approximately 442MW. Two of the projects are located in Texas, one of which is scheduled to commence construction this fall, while the other is scheduled to commence construction in the summer of 2008. The former project is contingent upon reaching a joint development and ownership agreement with a third party by the end of the third quarter 2007. The latter project is located in the Southern California marketplace with construction planned for the early summer of 2009. The total project cost for all three projects, net of third party contributions, is estimated at \$682 million. Project level financing is expected to range from approximately 50% – 80% of project costs, thereby requiring a net cash investment by the Company of approximately \$252 million. The expected capital cost for 2007 is \$177 million of which \$47 million is projected to be funded through non-recourse debt.

Development Costs

During the first half of 2007, NRG incurred approximately \$59 million in costs associated with development efforts related to *RepoweringNRG* initiatives, of which \$39 million has been spent towards STP, mainly for engineering studies required in preparation for the submission of a combined operating license application towards the construction of Units 3 and 4.

The following table summarizes the Company's *RepoweringNRG* capital expenditures for the full year 2007 as well as what has been spent through the first half of 2007 by region:

(In millions)	<i>RepoweringNRG</i>
Northeast	\$ 6
Texas	20
West	75
Wind and other projects	179
Total	\$ 280
<i>RepoweringNRG</i> capital expenditures through June 30, 2007	78
Remaining <i>RepoweringNRG</i> capital expenditures for 2007	\$ 202

Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications.

Retained or Contingent Interests

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

Derivative Instrument obligations

On August 11, 2005, NRG issued 3.625% Preferred Stock that includes a feature which is considered an embedded derivative per FAS 133, as amended. Although it is considered an embedded derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of FAS 133. As of June 30, 2007, based on the Company's stock price, the value of this embedded derivative was approximately \$174 million.

On October 13, 2006, NRG through its unrestricted wholly-owned subsidiaries NRG Common Stock Fund I and NRG Common Stock Fund II, issued notes and preferred interests for the repurchase of NRG's common stock. Included in the agreement is a feature which is considered an embedded derivative per FAS 133, as amended. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of FAS 133. As of June 30, 2007, based on the Company's stock price, the value of this embedded derivative was approximately \$97 million.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments — As of June 30, 2007, NRG had not entered into any financing structure that was designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to the Company. However, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy-related entities that are accounted for under the equity method of accounting. NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately \$138 million as of June 30, 2007. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG.

Synthetic Letter of Credit Facility and Revolver Facility — Under NRG's amended Senior Credit Facility which the company entered in to on June 8, 2007, the Company has a \$1.3 billion synthetic Letter of Credit Facility which is secured by a \$1.3 billion cash deposit at Deutsche Bank AG, New York Branch, the Issuing Bank. This deposit was funded using proceeds from the Term B loan investors who participated in the facility syndication. Under the Synthetic Letter of Credit Facility, NRG is allowed to issue letters of credit for general corporate purposes including posting collateral to support the Company's commercial operations activities. In addition, NRG can issue up to \$300 million in unfunded letters of credit under the Company's Revolving Credit Facility for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the Senior Credit Facility. In addition, NRG is permitted to issue additional letters of credit of up to \$700 million under the Senior Credit Facility through another financial institution.

As of June 30, 2007, the Company had issued \$1.2 billion in letters of credit under the Synthetic Letter of Credit Facility. In addition, as of June 30, 2007, the Company had issued \$71 million in letters of credit under the Revolving Credit Facility. A portion of these letters of credit supports non-commercial letter of credit obligations.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs, as disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2006. Also see Note 14, *Commitments and Contingencies*, to the condensed consolidated financial statements of this Form 10-Q for a discussion of new commitments and contingencies that also include contractual obligations and commercial commitments that occurred during the second quarter 2007.

Critical Accounting Estimates

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

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

Item 3 — Quantitative and Qualitative Disclosures About Market Risk

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

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

Commodity Price Risk

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

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

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

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

NRG measures the sensitivity of the Company's portfolio to potential changes in market prices using Value at Risk, or VAR. VAR is a statistical model that attempts to predict risk of loss based on market price volatility. Currently, the company estimates VAR using a Monte Carlo simulation based methodology. NRG's total portfolio includes mark-to-market and non mark-to-market energy assets and liabilities.

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

As of June 30, 2007, the VAR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VAR model was \$33 million.

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The following table summarizes average, maximum and minimum VAR for NRG for the three months ended June 30, 2007 and 2006. VAR for the three months ended June 30, 2006 does not include Texas since it was not integrated with the consolidated NRG portfolio.

VAR	2007	2006
As of June 30,	\$ 33	\$ 35
Average	22	32
Maximum	33	35
Minimum	15	28

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

In order to provide additional information for comparative purposes to NRG's peers, the Company also uses VAR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VAR for the derivative financial instruments calculated using the diversified VAR model as of June 30, 2007 for the entire term of these instruments entered into for both asset management and trading was approximately \$14 million.

Interest Rate Risk

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

In January 2006, the Company entered into a series of new interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, NRG pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the equivalent of a floating interest payment based on 3-month LIBOR rate calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of July 27, 2007 was \$2.03 billion.

As of June 30, 2007, the Company had various interest rate swap agreements with notional amounts totaling approximately \$2.7 billion. If the swaps had been discontinued on June 30, 2007, the counterparties would have owed the Company approximately \$7 million. Based on the investment grade rating of the counter-parties, NRG believes that the Company's exposure to credit risk due to nonperformance by the counter-parties to the hedging contracts is insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of June 30, 2007, a 100 basis point change in interest rates would result in a \$16 million change in interest expense on a rolling twelve month basis.

As of June 30, 2007, both the fair value and the carrying amount of the Company's long-term debt was approximately \$8.7 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company's long-term debt by \$531 million.

Currency Exchange Risk

NRG expects to continue to be subject to currency risks associated with foreign denominated distributions from the Company's international investments. In the normal course of business, NRG may receive distributions denominated in the Euro, Australian Dollar and the Brazilian Real. NRG has historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to the extent required, fixing the U.S. Dollar equivalent of net foreign

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denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. The Company would expect to enter into similar transactions in the future if management deems them to be appropriate.

Liquidity Risk

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

Based on a sensitivity analysis, a \$1 per MWh increase or decrease in electricity prices across the term of the marginable contracts would cause a change in margin collateral outstanding of approximately \$27 million as of June 30, 2007. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of June 30, 2007.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages the credit risk of NRG and its subsidiaries through credit policies which include (i) an established credit approval process, (ii) a daily monitoring of counterparty credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements, and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company has credit protection within various agreements to call on additional collateral support if and when necessary. As of June 30, 2007, NRG held collateral support of approximately \$472 million from counterparties.

A portion of NRG's credit risk is related to transactions that are recorded on the Company's consolidated Balance Sheet. These transactions primarily consist of open positions from the Company's commercial and risk management operations that are accounted for using mark-to-market accounting, as well as amounts owed by counterparties for transactions that settled but have not yet been paid.

The following table highlights the credit quality and exposures related to these activities as of June 30, 2007:

(In millions, except ratios) Credit Exposure	Exposure Before Collateral	Collateral	Net Exposure
Investment grade	\$1,360	\$ 426	\$ 934
Non-investment grade	48	13	35
Not rated	169	9	160
Total	\$1,577	\$ 448	\$1,129
Investment grade	86%	95%	83%
Non-investment grade	3	3	3
Not rated	11%	2%	14%

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

NRG's exposure to significant counterparties greater than 10% of the exposure before collateral was approximately \$638 million as of June 30, 2007. NRG does not anticipate any material adverse effect on the Company's financial position or results of operations as a result of nonperformance by any of NRG's counterparties.

Fair Value of Derivative Instruments

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

NRG's trading activities include contracts entered into to profit from market price changes as opposed to hedging an exposure, and are subject to limits in accordance with the Company's risk management policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings. These trading activities are a complement to NRG's energy marketing portfolio.

The tables below disclose the activities that include non-exchange traded contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at June 30, 2007, based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at June 30, 2007:

Derivative Activity Gains/(Losses)	(In millions)
Fair value of contracts as of December 31, 2006	\$ 354
Contracts realized or otherwise settled during the period	(45)
Changes in fair value	(545)
Fair value of contracts as of June 30, 2007	\$ (236)

Sources of Fair Value Gains/(Losses) (In millions)	Fair Value of Contracts as of June 30, 2007				Total Fair Value
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	
Prices actively quoted	\$ 10	\$ 7	\$ —	\$ —	\$ 17
Prices provided by other external sources	107	(113)	(227)	(39)	(272)
Prices provided by models and other valuation methods	5	15	(1)	—	19
Total	\$ 122	\$ (91)	\$ (228)	\$ (39)	\$ (236)

Item 4 — Controls and Procedures

Under the supervision and with the participation of Company's management, including the principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the Company's disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, NRG's principal executive officer, principal financial officer and principal accounting officer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this Quarterly Report. There have been no changes in the Company's internal control over financial reporting during the quarter ended June 30, 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1 — Legal Proceedings

For a discussion of material legal proceedings in which NRG was involved through June 30, 2007, see Note 14, *Commitments and Contingencies*, to the condensed consolidated financial statements of this Form 10-Q.

Item 1A — Risk Factors

Information regarding risk factors appears in Part I, Item 1A, Risk Factors in NRG Energy, Inc.'s 2006 Annual Report on Form 10-K for the fiscal year ended December 31, 2006 and Part II, Item 1A, Risk Factors in NRG's Quarterly Report on Form 10-Q for the period ended March 31, 2007.

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

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

For the period ended June 30, 2007	Total number of shares purchased (a)	Average price paid per share (a)	Total number of shares purchased as part of publicly announced plans or programs (a)	Dollar value of shares that may be purchased under the plans or programs
First quarter 2007	3,000,000	\$ 34.37	3,000,000	\$ 165,160,714
April 1 – April 30	—	—	—	—
May 1 – May 31	2,669,200	42.16	2,669,200	52,615,547
June 1 – June 30	—	—	—	—
Second quarter 2007 Total	2,669,200	42.16	2,669,200	
Year-to-date	5,669,200	\$ 38.04	5,669,200	\$ 52,615,547

(a) Reflects the impact of a two-for-one stock split as discussed in Note 8, *Changes in Capital Structure*, of this Form 10-Q

On November 3, 2006, as part of Phase II of the Company's Capital Allocation Program discussed in Note 8, *Changes in Capital Structure*, NRG announced an increase to the share repurchase program to a \$500 million stock buyback. As originally announced on August 1, 2006, Phase II was only to be a \$250 million stock buyback. NRG expects to complete Phase II during the third quarter 2007, with repurchases of approximately \$53 million in NRG common stock.

Item 3 — Defaults upon Senior Securities

None.

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

The stockholders of NRG Energy, Inc. voted on two items at the Annual Meeting of Stockholders held on April 25, 2007. No adjustment has been reflected in the numbers below as a result of the stock split.

1. The election of Class I Directors to a three-year term.
2. The proposal to ratify the appointment of KPMG LLP as NRG's independent registered public accounting firm.

The four individuals named below were elected to serve a three-year term as Class I Directors expiring at the Annual Meeting of Stockholders in 2010:

Nominee	Votes For	Votes Withheld
David Crane	100,546,789	2,853,777
Stephen L. Cropper	100,514,538	2,886,028
Maureen Miskovic	100,556,215	2,844,351
Thomas H. Weidemeyer	100,555,647	2,844,919

The names of the directors whose terms of office as directors continued after the meeting are as follows:

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Class II: Lawrence S. Coben, Paul W. Hobby, Herbert H. Tate and Walter R. Young
Class III: John F. Chlebowski, Howard E. Cosgrove, William E. Hantke and Anne C. Schaumburg

The proposal to ratify the appointment of KPMG LLP as independent registered public accounting firm was ratified with 102,579,033 shares voting for, 602,512 shares voting against, 219,021 shares abstaining and zero broker non-votes.

Item 5 — Other Information

None.

Item 6 — Exhibits

(a) Exhibits

- 4.1 Tenth Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
- 4.2 Eleventh Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
- 4.3 Twelfth Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
- 10.1 Credit Agreement dated June 8, 2007 by and among NRG Holdings, Inc., the lenders party thereto, Credit Suisse Securities (USA) LLC, Credit Suisse and Citigroup Global Markets Inc. (2)
- 10.2 Second Amended and Restated Credit Agreement dated June 8, 2007 by and among NRG Energy, Inc., the lenders party thereto, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Citicorp North America Inc. and Credit Suisse. (2)
- 31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
- 31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
- 31.3 Certification of Controller pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
- 32 Certification of Chief Executive Officer, Chief Financial Officer and Controller pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, filed herewith.

(1) Incorporated herein by reference to NRG Energy Inc's current report on Form 8-K filed on July 20, 2007.

(2) Incorporated herein by reference to NRG Energy Inc's current report on Form 8-K filed on June 13, 2007.

SIGNATURES

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

NRG ENERGY, INC.
(Registrant)

/s/ DAVID W. CRANE
David W. Crane,
Chief Executive Officer

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

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

Date: August 2, 2007

Exhibit Index

- 4.1 Tenth Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
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- 4.3 Twelfth Supplemental Indenture, dated July 19, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
- 10.1 Credit Agreement dated June 8, 2007 by and among NRG Holdings, Inc., the lenders party thereto, Credit Suisse Securities (USA) LLC, Credit Suisse and Citigroup Global Markets Inc. (2)
- 10.2 Second Amended and Restated Credit Agreement dated June 8, 2007 by and among NRG Energy, Inc., the lenders party thereto, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Citicorp North America Inc. and Credit Suisse. (2)
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- 32 Certification of Chief Executive Officer, Chief Financial Officer and Controller pursuant to Section 906 of the Sarbanes- Oxley Act of 2002, 18 U.S.C. Section 1350, filed herewith.

(1) Incorporated herein by reference to NRG Energy Inc's current report on Form 8-K filed on July 20, 2007.

(2) Incorporated herein by reference to NRG Energy Inc's current report on Form 8-K filed on June 13, 2007.

CERTIFICATION

I, David Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID W. CRANE

David W. Crane
Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2007

CERTIFICATION

I, Robert C. Flexon, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ROBERT C. FLEXON

Robert C. Flexon

Chief Financial Officer

(Principal Financial Officer)

Date: August 2, 2007

CERTIFICATION

I, Carolyn J. Burke, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CAROLYN J. BURKE

Carolyn J. Burke

Controller

(Principal Accounting Officer)

Date: August 2, 2007

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

In connection with the Quarterly Report of NRG Energy, Inc. on Form 10-Q for the quarter ended June 30, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-Q"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

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

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

Date: August 2, 2007

/s/ DAVID W. CRANE

David W. Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON

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

/s/ CAROLYN J. BURKE

Carolyn J. Burke,
Controller
(Principal Accounting Officer)

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

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