PRESSURE BIOSCIENCES INC
Form 4
December 16, 2013

FORM 4

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Urdea michael S

(Last) (First) (Middle)

100 BUNCE MEADOWS DRIVE

(Street)

ALAMO, CA 94507

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
PRESSURE BIOSCIENCES INC [PBIO]

3. Date of Earliest Transaction (Month/Day/Year)
12/12/2013

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security	2. Conversion or Exercise	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any	4. Transaction Code	5. Number of Derivative Securities	6. Date Exercisable and Expiration Date (Month/Day/Year)	7. Title and Amou Underlying Securi (Instr. 3 and 4)

(Instr. 3)	Price of Derivative Security		(Month/Day/Year)	(Instr. 8)		Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)					
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amo Num Sha
Series K Convertible Preferred Stock	$ 0.25	12/12/2013		P		130		12/12/2013 (1)	12/12/2014	Common Stock	130
Series K Common Stock Purchase Warrant	$ 0.3125	12/12/2013		P		65,000		12/12/2013 (3)	12/12/2016	Common Stock	65

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Urdea michael S 100 BUNCE MEADOWS DRIVE ALAMO, CA 94507	X			

Signatures

/s/ Michael S. Urdea	12/16/2013
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The terms of the Series K Convertible Preferred Stock contain a limitation on conversion which prevents the Reporting Person from converting shares of Series K Convertible Preferred Stock if, after giving effect to the conversion, the Reporting Person would beneficially own more than 4.99% of the outstanding shares of Common Stock. The Reporting Person may elect to increase this limitation to 9.99%, 14.99%, or 19.99% upon not less than 61 days prior written notice to the Company. Since the Reporting Person currently beneficially owns less than 4.99% of the outstanding shares of Common Stock, the conversion limitation that applies to the Reporting Person is the 4.99% limitation. The Reporting Person disclaims beneficial ownership of such securities except to the extent of the Reporting Person's pecuniary interest in such securities.

(2) Pursuant to a certain Securities Purchase Agreement dated December 12, 2013, among the Company, the Reporting Person, and the other purchasers named therein, the Reporting Person purchased 130 "Units" at a purchase price of $250 per Unit. Each Unit consisted of (i) one share of Series K Convertible Preferred Stock, convertible into 1,000 shares of the Company's Common Stock, and (ii) a warrant to purchase 500 shares of Common Stock, which warrant is exercisable until December 12, 2016.

(3) The Series K Common Stock Purchase Warrants contain a limitation on exercise which prevents the Reporting Person from exercising any Warrants if, after giving effect to the exercise, the Reporting Person would beneficially own more than 4.99% of the outstanding shares of Common Stock. The Reporting Person may elect to increase this limitation to 9.99%, 14.99%, or 19.99% upon not less than 61 days prior written notice to the Company. Since the Reporting Person currently beneficially owns less than 4.99% of the outstanding shares of Common Stock, the exercise limitation that applies to the Reporting Person is the 4.99% limitation. The Reporting Person disclaims beneficial ownership of such securities except to the extent of the Reporting Person's pecuniary interest in such securities.

Accumulated OCI balance at September 30, 2007
$(69) $ $(69)

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

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

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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 nine months ended September 30, 2006, net of tax:

(In millions)	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at December 31, 2005	$ (204)	$ 8	$ (196)
Realized from OCI during the period:			
Due to realization of previously deferred amounts	26	(2)	24
Mark-to-market of hedge contracts	299	9	308
Accumulated OCI balance at September 30, 2006	$ 121	$ 15	$ 136

As of September 30, 2007, the net balance in OCI relating to SFAS 133 was an unrecognized loss of approximately $69 million, which is net of $46 million in income taxes. NRG expects $39 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 and nine months ended September 30, 2007 and 2006, respectively:

	Three months ended September 30		Nine months ended September 30	
(In millions)	2007	2006	2007	2006
Revenue from operations energy commodities	$ 6	$ 183	$ (41)	$ 300
Interest expense interest rate swaps				(3)
Total impact to statement of operations	$ 6	$ 183	$ (41)	$ 297

For the three months ended September 30, 2007, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $6 million was comprised of a $13 million gain from trading activity partially offset by a $7 million loss from economic hedges. The loss from economic hedges includes a $7 million gain due to ineffectiveness related to gas swaps and collars reflecting a change in the correlation between natural gas and power prices as of September 30, 2007.

For the nine months ended September 30, 2007, the unrealized loss associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $41 million was comprised of a $55 million loss from economic hedges partially offset by a $14 million gain from trading activity. The loss from economic hedges includes a $28 million gain due to ineffectiveness related to gas swaps and collars reflecting a change in the correlation between natural gas and power prices.

For the three months ended September 30, 2006, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $183 million was comprised of a $198 million gain from economic hedges partially offset by a $15 million loss from trading activity. The gain from economic hedges includes a $78 million gain due to ineffectiveness related to gas swaps and collars reflecting a change in the correlation between natural gas and power prices.

For the nine months ended September 30, 2006, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $300 million was comprised of $310 million gain from economic hedges partially offset by a $10 million loss from trading activity. The gain from economic hedges includes a $121 million gain due to ineffectiveness related to gas swaps and collars reflecting a change in the correlation between natural gas and power prices. 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.

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Note 7 Long Term Debt

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

Upon completion of the contemplated Comprehensive Capital Allocation Plan:

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

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

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

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 Facility 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 Company s results of operations for the nine months ended September 30, 2007, which was 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 cash dividends on common stock, upon the implementation of the Holdco structure;

exclude payments made on the Holdco Credit Facility, once funded, from being considered restricted payments under the Senior Credit Facility;

modify the existing excess cash flow prepayment mechanism to provide that prepayments are offered to both NRG and Holdco on a pro rata basis and to provide for mandatory annual prepayments; 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.

On August 6, 2007, NRG entered into an agreement with BNP Paribas, or BNP, whereby BNP has agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. BNP has agreed to issue up to $350 million of letters of credit under the revolver at a rate of 0.25% of the amount issued. NRG will pay BNP a letter of credit issuance fee in the amount of $250 per each letter of credit issued. This increases the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility to $650 million. In addition, NRG is permitted to issue additional letters of credit of up $350 million under the Senior Credit Facility through other financial institutions.

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 as of September 30, 2007.

The formation of the Holdco structure and the drawdown on the Holdco Credit Facility are subject to certain conditions including approval by several regulatory bodies. The Company expects to be able to satisfy these conditions during the fourth quarter 2007.

With the recent recovery in financial markets and the prices of NRG s Senior Notes, on November 2, 2007, the Company exercised its right to provide its Senior Note holders with a conditional change of control notice, and related offer to purchase the Company s Senior Notes at 101% of par, prior to the actual formation of the Holdco structure. Concurrent with this change of control offer, NRG is seeking consent from the same Senior Note holders to waive the change of control in exchange for a 0.125% fee. Under the terms of the Company s Senior Notes, holders will have thirty calendar days to respond to the change of control offer and consent solicitation.

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Based on the outcome of this change of control offer and consent solicitation, NRG will make a determination of whether to move forward with the Holdco structure prior to the end of 2007. If the Holdco Credit Facility is drawn, the net proceeds will simultaneously be used to pay down a portion of the Company s Term B loan under its Senior Credit Facility. As a result, the Company s Senior Notes restricted payments capacity that governs, among other things, the amount of capital that can be returned to shareholders will expand by a similar amount. In addition, NRG will retain the right, but not the obligation, to purchase any or all of the Senior Notes tendered by investors during this process regardless of whether NRG decides to move forward and form the Holdco structure.

In connection with the transaction, Bank of America has provided the Company with a $4.2 billion senior unsecured debt financing commitment, subject to customary conditions, to fund the tender offers together with a portion of the Company s cash on hand.

Note 8 Changes in Capital Structure

Stock Split

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

The following table reflects the changes in NRG s common stock issued and outstanding for the nine months ended September 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 2007			(7,006,700)	(7,006,700)
Shares issued from LTIP through September 30, 2007		952,519		952,519
Retirement of shares through September 30, 2007		(14,094,962)	14,094,962	
Balance as of September 30, 2007	500,000,000	261,105,821	(22,512,900)	238,592,921
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
Capital Allocation Program Phase I during 2006			(12,226,000)	(12,226,000)
Shares issued from LTIP through September 30, 2006		134,810		134,810
Balance as of September 30, 2006	500,000,000	274,061,284	(12,226,000)	261,835,284

Common Stock

NRG s authorized common stock consists of 500 million shares of NRG stock. Common stock issued as of September 30, 2007 and 2006 was 261,105,821 and 274,061,284 shares, respectively.

Treasury Stock

In 2006, NRG initiated a Capital Allocation Program to be executed in two phases. Phase I, completed in the fourth quarter 2006, resulted in the repurchase of 21,175,400 shares of the Company s common stock for approximately $500 million. Phase II, also a $500 million share buyback program, began in the fourth quarter 2006 with the repurchase of 8,425,762 shares of NRG common stock for approximately $232 million. NRG completed Phase II in the third quarter 2007, with the repurchase of 1,337,500 shares of the Company s common stock for approximately $53 million. The Company has thus repurchased 7,006,700 shares of NRG common stock for approximately $268 million for the nine months ended September 30, 2007.

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. The notes and preferred interest with CSF I and CSF II mature in 2008 and 2009, respectively. 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, or CAGR, of 20% beyond the volume-weighted average share price of the stock at the time of repurchase. Although this feature is considered a derivative, it is exempt from derivative accounting under the guidance in paragraph 11(a) of SFAS

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133, and will be only be recognized upon settlement with a corresponding impact to Additional Paid-In Capital. As of September 30, 2007, based on the Company s stock price, the redemption value of this embedded derivative was approximately $72 million.

Retirement of Treasury Stock

On May 22, 2007, 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*.

Non-Qualified Stock Options, or NQSO s

The following table summarizes the change in the Company s outstanding NQSO balance for the nine months ended September 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	784,350	28.63	8.28
Forfeited	(156,805)	24.25	7.34
Exercised	(291,180)	15.65	5.88
Outstanding at September 30, 2007	3,747,437	19.77	7.07
Exercisable at September 30, 2007	1,987,917	$ 14.06	$ 6.45

Restricted Stock Units, or RSU s

The following table shows the change in the outstanding RSU balance during the nine months ended September 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	561,230	38.54
Vested	(1,097,900)	10.56
Forfeited	(91,250)	21.46
Outstanding as of September 30, 2007	1,649,266	$ 26.64

Performance Units, or PU s

The following table shows the change in the outstanding PU balance during the nine months ended September 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	189,300		18.10
Forfeited	(56,000)		16.51
Outstanding as of September 30, 2007	543,964	$	17.66

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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 September 30 2007	Three months ended September 30 2006	Nine months ended September 30 2007	Nine months ended September 30 2006
Basic earnings per share				
Numerator:				
Income from continuing operations	$ 268	$ 371	$ 482	$ 588
Preferred stock dividends	(13)	(14)	(41)	(38)
Net income available to common stockholders from continuing operations	255	357	441	550
Discontinued operations, net of income tax expense		51		63
Net income available to common stockholders	$ 255	$ 408	$ 441	$ 613
Denominator:				
Weighted average number of common shares outstanding	239.4	272.4	240.5	260.6
Basic earnings per share:				
Income from continuing operations	$ 1.07	$ 1.31	$ 1.83	$ 2.11
Discontinued operations, net of income tax expense		0.19		0.24
Net income	$ 1.07	$ 1.50	$ 1.83	$ 2.35
Diluted earnings per share				
Numerator:				
Net income available to common stockholders from continuing operations	$ 255	$ 357	$ 441	$ 550
Add preferred stock dividends for dilutive preferred stock	11	11	34	32
Adjusted income from continuing operations	266	368	475	582
Discontinued operations, net of tax		51		63
Net income available to common stockholders	$ 266	$ 419	$ 475	$ 645
Denominator:				
Weighted average number of common shares outstanding	239.4	272.4	240.5	260.6
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	3.8	3.0	3.7	2.8
Incremental shares attributable to embedded derivatives of certain financial instruments (if-converted method)	4.6		4.9	
Incremental shares attributable to assumed conversion features of outstanding preferred stock (if-converted method)	37.5	41.6	37.5	39.2
Total dilutive shares	285.3	317.0	286.6	302.6
Diluted earnings per share:				
Income from continuing operations	$ 0.93	$ 1.16	$ 1.66	$ 1.92
Discontinued operations, net of tax		0.16		0.21

Net income	$ 0.93	$ 1.32	$ 1.66	$ 2.13

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

	Three months ended September 30		Nine months ended September 30	
(In millions of shares)	**2007**	**2006**	**2007**	**2006**
Equity compensation (NQSO s and PU s)		0.9	0.4	2.1
5.75% convertible preferred stock				2.4
Embedded derivative of 3.625% redeemable perpetual preferred stock	13.2	16.0	13.0	16.0
Embedded derivative of preferred interests and notes issued by CSF I and CSF II	16.7	10.6	16.6	10.6
Total	29.9	27.5	30.0	31.1

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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 has been recast 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 Form 10-K.

(In millions)	Wholesale Power Generation								
Three months ended September 30, 2007	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 956	$ 502	$ 200	$ 33	$ 52	$ 36	$ 7	$	$ 1,786
Depreciation and amortization	113	25	17	1	1	3	1		161
Equity in earnings of unconsolidated affiliates				1	18				19
Income/(loss) from continuing operations before income taxes	275	171	18	13	30	4	(96)		415
Net income/(loss)	161	171	17	13	54	4	(152)		268
Total assets	12,308	1,566	996	246	1,135	213	12,774	(10,034)	19,204

(In millions)	Wholesale Power Generation								
Three months ended September 30, 2006	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 1,151	$ 478	$ 171	$ 59	$ 46	$ 38	$ (1)	$	$ 1,942
Depreciation and amortization	104	22	17		1	3	1		148
Equity in earnings of unconsolidated affiliates				3	15		(1)		17
Income/(loss) from continuing operations before income taxes	480	152	18	12	27	6	(86)		609
Income from discontinued operations, net of income taxes					51				51
Net income/(loss)	445	153	18	13	74	6	(287)		422

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(In millions) Nine months ended September 30, 2007	Wholesale Power Generation Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 2,526	$ 1,239	$ 514	$ 90	$ 139	$ 122	$ 29	$ (15)	$ 4,644
Depreciation and amortization	341	74	51	2	2	9	4		483
Equity in earnings of unconsolidated affiliates				(2)	42				40
Income/(loss) from continuing operations before income taxes	624	319	24	26	77	32	(304)	(12)	786
Net income/(loss)	355	319	23	26	88	32	(349)	(12)	482

(In millions) Nine months ended September 30, 2006	Wholesale Power Generation Texas (a)	Northeast	South Central	West (b)	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 2,498	$ 1,196	$ 437	$ 109	$ 133	$ 114	$ 10	$ (18)	$ 4,479
Depreciation and amortization	309	66	51	1	2	9	5		443
Equity in earnings of unconsolidated affiliates				2	43		1		46
Income/(loss) from continuing operations before income taxes	765	335	32	17	80	12	(311)	(18)	912
Income from discontinued operations, net of income taxes					50		13		63
Net income/(loss)	719	335	32	19	113	12	(561)	(18)	651

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

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

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Note 12 Income Taxes

Income tax expense for the three and nine months ended September 30, 2007 was $147 million and $304 million, respectively, compared to income tax expense of $238 million and $324 million for the three and nine months ended September 30, 2006, respectively. The income tax expense for the three and nine months ended September 30, 2007 includes domestic tax expense of $170 million and $314 million, respectively, and foreign tax benefit of $23 million and $10 million, respectively. The income tax expense for the three and nine months ended September 30, 2006 includes domestic tax expense of $234 million and $307 million, respectively, and foreign tax expense of $4 million and $17 million, respectively.

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

	Nine months ended September 30	
(In millions except rate data)	**2007**	**2006**
Income from continuing operations before income taxes	$ 786	$ 912
Tax at 35%	275	319
State taxes	37	47
Valuation allowance	2	2
Disputed claims reserve		(29)
Foreign operations	(9)	(23)
Foreign dividends	21	2
Non-deductible interest	7	
Change in German tax rate	(30)	
Permanent differences including subpart F income	1	6
Income tax expense	$ 304	$ 324
Effective income tax rate	38.7%	35.5%

The effective income tax rate for the nine months ended September 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 including the impact of a law change that reduced the German tax rate. For the nine months ended September 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 September 30, 2007, NRG recorded a net deferred tax liability of $749 million. 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 $589 million of tax assets, thus a valuation allowance has remained.

NOL carryforwards As of September 30, 2007, the Company had generated total domestic pretax book income of $708 million which fully utilized cumulative domestic net operating loss, or NOL, in the amount of $65 million. In addition, as of September 30, 2007, NRG has cumulative foreign NOL carryforwards of $290 million of which $78 million will expire in 2016 and of which $212 million do not have an expiration date.

Uncertain tax benefits

NRG has identified certain unrecognized tax benefits whose after-tax value was $712 million, of which $19 million would impact the Company s effective tax rate if recognized. Of the $712 million in unrecognized tax benefits, $693 million relates to periods prior to the Company s emergence from bankruptcy. 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, recognition of previously unrecognized tax benefits existing pre-emergence would not impact the Company s effective tax rate but would increase Additional Paid in Capital. As of September 30, 2007, NRG has recorded a $51 million non-current tax liability for unrecognized tax benefits. This amount was recorded after utilization in 2007 of the cumulative domestic NOL.

NRG has accrued interest and penalties related to these unrecognized tax benefits of approximately $4 million as of the adoption of FIN 48 by the Company on January 1, 2007. The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. For the three and nine months ended September 30, 2007, the Company incurred an immaterial amount of interest and penalties related to its unrecognized tax benefits.

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

German Tax Reform Act 2008

On July 6, 2007, the German government passed the Tax Reform Act of 2008, which reduces the German statutory and resulting effective tax rates on earnings from approximately 36% to approximately 27% effective January 1, 2008. Due to this reduction in the statutory and resulting effective tax rate, during the third quarter 2007, NRG recognized a $30 million tax benefit and as of September 30, 2007, NRG had a German net deferred tax liability of approximately $79 million which includes the impact of this tax rate change.

Note 13 Benefit Plans and Other Postretirement Benefits

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

	Defined Benefit Pension Plans			
	Three months ended September 30,		**Nine months ended September 30,**	
(In millions)	**2007**	**2006**	**2007**	**2006**
Service cost benefits earned	$ 3	$ 4	$ 11	$ 13
Interest cost on benefit obligation	4	4	13	12
Expected return on plan assets	(3)	(2)	(9)	(5)
Net periodic benefit cost	$ 4	$ 6	$ 15	$ 20

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

	Other Postretirement Benefits Plans			
	Three months ended September 30,		**Nine months ended September 30,**	
(In millions)	**2007**	**2006**	**2007**	**2006**
Service cost benefits earned	$ 1	$ 1	$ 2	$ 2
Interest cost on benefit obligation	2	1	4	3
Net periodic benefit cost	$ 3	$ 2	$ 6	$ 5

The total amount of employer contributions paid for the nine months ended September 30, 2007 was $70 million. NRG does not expect to make any further contributions for the remainder of 2007.

Note 14 Commitments and Contingencies

Commitments

First and Second Lien Structure

NRG has granted first and 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 first or 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 first and 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 part of NRG s amended and restated credit agreement signed June 8, 2007, the Company obtained the ability to move its current second lien counterparty exposure to the first lien, on a pari passu basis with the Company s existing first lien lenders. In exchange for moving some second lien holders to a pari passu basis with the Company s first lien lenders, the counterparties will relinquish letters of credit issued by NRG which they held as a part of their collateral package.

As of September 30, 2007, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the second lien structure was approximately $23 million. On October 30, 2007, NRG successfully moved certain second lien holders to a

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pari passu basis with the Company s first lien lenders effectively releasing $557 million of letters of credit. With the movement to the first lien structure, the Company significantly reduces its outstanding letters of credit exposure and thereby increases its liquidity.

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 nine months ended September 30, 2007 with total commitments of approximately $510 million and $713 million, respectively, spanning over the next three to ten years.

As discussed below under contingencies, the Company renegotiated its long term contract with Texas Westmoreland Coal Co., or TWCC, for the mining of the Jewett Mine adjacent to the Limestone facility. As a result, the Company s estimated commitments to procure fuel and transportation service decreased by $912 million as reported previously under Note 21, *Commitments and Contingencies*, to the Company s financial statements in the Form 10-K. Per the renegotiated terms, NRG can reassess its coal needs on an annual basis, thus, the total commitments related to TWCC only include 2008 contractual amounts.

Repowering*NRG *Project Deposits

NRG has made non-refundable deposits relating to *Repowering*NRG initiatives totaling approximately $30 million primarily towards the procurement of wind turbines. 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 deposits 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 can be reasonably estimated. 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 that these legal proceedings and investigations 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

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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. On October 3, 2005, the court sustained defendants demurrer, dismissing the case against all remaining defendants including WCP s subsidiaries. On February 26, 2007, the California State Court of Appeals Fourth District, 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 with prejudice against NRG only on May 17, 2006, by the U.S. Bankruptcy Court in New York and plaintiffs did not appeal. Other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers that name WCP and/or subsidiaries of WCP, in addition to numerous other defendants. These complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California s antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys fees, and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several of these proceedings.

In August 2006, Dynegy executed a settlement agreement to resolve the class action claims in the natural gas anti-trust cases consolidated and pending in state court in San Diego, California. Approved in late December 2006, the Court dismissed the class action claims. WCP and some of its subsidiaries were named defendants and Dynegy s settlement included full releases for these entities. The settlement resolved 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 excluded similar cases filed by individual plaintiffs. 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 October 2007, Dynegy reached a tentative settlement of all remaining coordinated natural gas index cases pending in state court in San Diego. The settlement has yet to be funded by Dynegy and requires court approval. Neither WCP and its subsidiaries nor NRG paid any defense costs nor will it pay any settlement costs as Dynegy owed and continues to provide 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. On May 3, 2007, WCP and the other defendants filed separate petitions for certiorari seeking review by the U.S. Supreme Court and on September 25, 2007, the Court agreed to hear two of the filed petitions. Although WCP s petition was not selected for review, the Court s ultimate decision with respect to the other defendants petitions will apply equally to WCP. A decision is expected from the Court during the second half of 2008. 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, NRG Power Marketing Inc., or PMI, sought recovery in the U.S. District Court for Connecticut for amounts it claimed were owed for congestion charges under the October 29, 1999 Standard Offer Services Contract. CL&P withheld approximately $30 million from amounts owed to PMI under contract and PMI counterclaimed. CL&P s motion for summary judgment was granted by the Court on July 20, 2007. PMI did not appeal from this decision thereby ending this case. The full amount withheld by CL&P was previously reserved as a reduction to outstanding accounts receivable and therefore no payment was required by PMI.

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Station Service Disputes

On October 2, 2000, Niagara Mohawk Power Corporation, or NiMo, commenced an action against NRG in New York state court seeking damages related to NRG s alleged failure to pay retail tariff amounts for utility services at the Dunkirk plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego plants. On October 8, 2002, by stipulation and order, this action was stayed pending submission to FERC of the disputes in the action. At FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo s petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on June 23, 2006, denied the appeal finding that New York Independent System Operator s, or NYISO s, station service program that permits generators to self supply their station power needs by netting consumption against production in a month is lawful. On April 30, 2007, the U.S. Supreme Court denied NiMo s request for review of the D.C. Circuit decision thus ending further avenues to appeal FERC s ruling in this matter. NRG believes it is adequately reserved.

On December 14, 1999, NRG acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an order finding that, at times when NRG is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration. On September 11, 2007, the parties argued the dispute before a three judge arbitration panel. A decision is expected during the fourth quarter 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 $124 million as of September 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, or the Jewett mine, adjacent to the facility under an amended long-term contract with TWCC, originally entered into in 1979. 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. During the third quarter of 2007, NRG and TWCC renegotiated a long-term contract that has significantly changed the contractual structure as well as extended the mining period. The new contract is based on a cost-plus arrangement with incentives and penalties to ensure proper management of the mine. NRG has flexibility to increase or decrease lignite purchases from the mine within certain ranges, including the ability to suspend or terminate lignite purchases with adequate notice. The mining period has been extended through 2018 with an option to extend the mining period by two five year intervals.

TWCC is responsible for performing ongoing reclamation activities at the mine until all lignite reserves have been exhausted. When production is completed at the mine, NRG will be responsible for final mine reclamation obligations. Due to an increase in reclamation estimates offset by the negotiated three-year extension of the mining contract, the Company s asset retirement obligation for mine reclamation costs increased by $5 million.

The Railroad Commission of Texas has imposed a bond obligation of approximately $76 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. The remaining sum of approximately $26 million has been bonded by the mine operator, TWCC. Under the terms of the new cost plus agreement with TWCC, NRG is required to maintain a corporate guarantee of TWCC s bond obligation in the amount of $50 million if CenterPoint Energy, Inc. s obligation lapses, or pay the costs of obtaining replacement performance assurance. Additionally, NRG is required to provide additional performance assurance over TWCC s current bond obligations if required by the Commission.

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Spring Creek Coal Company

In August 2007, Spring Creek Coal Company filed a complaint against NRG Texas LP, NRG South Texas LP, NRG Texas Power LLC, NRG Texas LLC, and NRG Energy, Inc. in the U.S. District Court for the federal district of Wyoming. The complaint alleges multiple breaches in 2007 of a 1978 coal supply agreement as amended by a later 1987 agreement, which plaintiff alleges is a take or pay contract. Damages in excess of $11 million are being sought. Certain of the defendants have filed a motion to dismiss for lack of personal jurisdiction and certain other defendants have filed a motion to dismiss for lack of a case in controversy. The court will hear both motions on February 4, 2008.

Disputed Claims Reserve

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

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company s Chapter 11 bankruptcy plan, totaling $25 million in cash and 5,082,000 shares of common stock. As of October 25, 2007, the reserve held approximately $10 million in cash and approximately 1,317,138 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. 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.

NRG filed its most recent triennial update of its market power analysis on March 26, 2007, and this filing was accepted by FERC on August 9, 2007. 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.

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, which is 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. Settlement proceedings are still ongoing.

On December 28, 2006, the Attorney General 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 with FERC on 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

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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.

New York On July 6, 2007, FERC issued an order establishing an approximately six-month paper hearing process to address reforms to the in-city Installed Capacity, or ICAP, market and to formulate comprehensive solutions. On October 4, 2007, the NYISO filed its proposal for revisions to the ICAP market for the New York City zone. While the NYISO s proposal will retain the existing ICAP market structure, it will impose additional market power mitigation on the current owners of Consolidated Edison s divested generation units in New York City (which include NRG s Arthur Kill and Astoria facilities) who are deemed to be pivotal suppliers. Specifically, the NYISO proposal will impose a reference price on pivotal suppliers and require bids to be submitted at or below the reference price. The reference price will be the expected clearing price based upon the intersection of the supply curve and the ICAP Demand Curve if all suppliers bid as price-takers. The NYISO proposal, if accepted by FERC, would result in a significant decrease in the clearing price for New York City capacity. Earlier this year, FERC had rejected proposed mitigation that would have effectively lowered the capacity offer cap for those units from $105/kW-year to $82/kW-year. Although that proposal was rejected on March 6, 2007, FERC initiated an investigation to determine the justness and reasonableness of the NYISO s in-city installed capacity market, setting a refund effective date of May 12, 2007. The NYISO s October 4, 2007, filing proposes that any market reforms should be implemented only prospectively and that no refunds should be required.

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 and oral argument is scheduled for November 16, 2007. Resettlement of the market, while viewed as unlikely, could have a material financial impact on the Company s results of operations.

PJM On August 23, 2007, several entities, including the New Jersey Board of Public Utilities, the District of Columbia Office of the People s Counsel, and the Maryland Office of People s Counsel, filed appeals of the FERC orders accepting the settlement of the locational capacity market for PJM Interconnection, LLC. The settlement, filed at FERC on September 29, 2006, by a broad group of PJM Market participants, provides for a capacity market mechanism known as the Reliability Pricing Model, or RPM, which is designed to provide a long-term price signal through competitive forward auctions. On December 22, 2006, FERC issued an order accepting the settlement, which was reaffirmed on rehearing by order dated June 25, 2007. The first RPM auction period for delivery year June 1, 2007 through May 31, 2008 was conducted earlier this year, and capacity payments pursuant to the RPM mechanism have commenced. A successful appeal by the appellants could disturb the settlement and create a refund obligation of capacity payments.

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, had appealed the CPUC orders seeking to overturn the CPUC approval of the PPA. By order dated August 2, 2007, the appellate court summarily denied the 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 I filing. NRG is not affected by the RMR agreement for Cabrillo I because Cabrillo I has a tolling agreement with a load-serving entity. Following settlement negotiations, FERC approved a settlement resulting in an annual fixed revenue requirement of approximately $5 million for Cabrillo II. On September 28, 2007, CAISO notified NRG that it desires to extend the RMR agreements for 2008 for both Cabrillo I and Cabrillo II. In light of the existing tolling arrangement for Cabrillo I with San Diego Gas & Electric, or SDG&E, and the emerging resource adequacy market, NRG is pursuing alternate arrangements with the CAISO that would eliminate the need for the RMR designations for some of the units.

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. New greenhouse gas legislation and regulations to mitigate the effects of gases, including CO_2 from power plants, are under consideration at the federal and state levels. In general, the effect of such future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions or additional costs on the Company s operations.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that capital expenditures to be incurred from 2007 through 2012 to keep NRG s facilities in compliance with environmental laws will be between $1.0 billion and $1.5 billion. The environmental capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with Clean Air Interstate Rule, the Clean Air Mercury Rule and related state requirements as well as installation of Best Technology Available under the Phase II 316(b) Rule. The range reflects alternative strategies available across the fleet.

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 cannot predict with certainty the outcome of this matter until the results of the investigation are fully evaluated.

In November 2006, DNREC promulgated Regulation No. 1146, or Reg 1146, Electric Generating Unit Multi-Pollutant Regulation and Section 111(d) of the State Plan for the Control of Mercury Emissions from Coal-Fired Electric Steam Generating Units. These regulations govern the control of SO_2, NO_x, and mercury emissions from electric generating units. NRG 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. This challenge was settled when DNREC and NRG signed a Consent Order on September 25, 2007, and filed that document with the Delaware Superior Court thereby ending the case. Under this agreement, continued operations at Indian River Generating Station are conditioned upon installation of controls on Units 1 and 2 by May 1, 2008 to reduce NO_x; installation of controls on Units 1-4 by January 1, 2009 to meet mercury requirements; mothball of Units 1 and 2 by May 1, 2011 and May 1, 2010, respectively; and installation of advanced controls on Units 3 and 4 in 2011 to further reduce NO_x and SO_2. If the plant emits NO_x in excess of 1,700 tons in any given ozone season, it will be subject to a graduated scale of stipulated penalties, up to a maximum $2,500/ton. The capital costs associated with this settlement are included in the Company s estimated environmental capital expenditures as previously discussed.

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 Form 10-K.

For the nine months ended September 30, 2007, NRG had net increases to its guarantee obligations under other commercial arrangements of approximately $153 million. These increases pertained to payment obligations of PMI.

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Note 18 Condensed Consolidating Financial Information

As of September 30, 2007, the Company had $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016 and $1.1 billion of 7.375% Senior Notes due 2017 outstanding. These notes are guaranteed by certain of NRG s current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

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

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

NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Cedar Bayou Development Company, LLC
NRG Construction LLC
Vienna Operations Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

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

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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 information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities.

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,685	$ 101	$	$	$ 1,786
Operating Costs and Expenses					
Cost of operations	878	67	(2)		943
Depreciation and amortization	153	5	3		161
General and administrative	36	4	39		79
Development costs	31		18		49
Total operating costs and expenses	1,098	76	58		1,232
Gain/(Loss) on sale of assets	(1)		1		
Operating Income/(Loss)	586	25	(57)		554
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	60		359	(419)	
Equity in earnings of unconsolidated affiliates	1	18			19
Other income, net	2	5	13	(5)	15
Interest expense	(59)	(24)	(95)	5	(173)
Total other income/(expense)	4	(1)	277	(419)	(139)
Income From Continuing Operations Before Income Taxes	590	24	220	(419)	415
Income tax expense/(benefit)	216	(21)	(48)		147
Net Income	$ 374	$ 45	$ 268	$ (419)	$ 268

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 4,359	$ 285	$	$	$ 4,644
Operating Costs and Expenses					
Cost of operations	2,380	189	1		2,570
Depreciation and amortization	460	19	4		483
General and administrative	85	11	140		236
Development costs	86		22		108
Total operating costs and expenses	3,011	219	167		3,397
Gain on sale of assets	16				16
Operating Income/(Loss)	1,364	66	(167)		1,263
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	114		768	(882)	
Equity in earnings/(losses) of unconsolidated affiliates	(2)	42			40
Write downs and gains on sale of equity method investments		1			1
Other income, net	7	23	30	(15)	45
Refinancing expense			(35)		(35)
Interest expense	(197)	(72)	(274)	15	(528)
Total other income/(expense)	(78)	(6)	489	(882)	(477)
Income From Continuing Operations Before Income Taxes	1,286	60	322	(882)	786
Income tax expense/(benefit)	472	(8)	(160)		304
Net Income	$ 814	$ 68	$ 482	$ (882)	$ 482

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

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NRG Energy, Inc. and Subsidiaries
Condensed Consolidating Balance Sheet
September 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	$ (4)	$ 153	$ 1,022	$	$ 1,171
Restricted Cash	1	61			62
Accounts receivable, net	499	37			536
Inventory	412	12			424
Derivative instruments valuation	827				827
Deferred income taxes	123	(18)	(60)		45
Prepayments and other current assets	181	35	350	(282)	284
Total current assets	2,039	280	1,312	(282)	3,349
Net property, plant and equipment	10,996	396	21		11,413
Other Assets					
Investment in subsidiaries	598		9,828	(10,426)	
Equity investments in affiliates	28	381			409
Notes receivable and capital lease	1,085	490	4,749	(5,834)	490
Goodwill	1,785				1,785
Intangible assets, net	898				898
Nuclear decommissioning trust	373				373
Derivative instruments valuation	214				214
Deferred income taxes		30			30
Other non-current assets	13	2	137		152
Intangible assets held-for-sale	91				91
Total other assets	5,085	903	14,714	(16,260)	4,442
Total Assets	$ 18,120	$ 1,579	$ 16,047	$ (16,542)	$ 19,204
LIABILITIES AND STOCKHOLDERS EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 41	$ 97	$ 31	$ (40)	$ 129
Accounts payable	(545)	229	672		356
Derivative instruments valuation	696				696
	385	95	191	(242)	429

Accrued expenses and other current liabilities					
Total current liabilities	577	421	894	(282)	1,610
Other Liabilities					
Long-term debt	4,749	828	8,876	(5,834)	8,619
Nuclear decommissioning reserve	302				302
Nuclear decommissioning trust liability	323				323
Deferred income taxes	655	(147)	316		824
Derivative instruments valuation	456	6	24		486
Out-of-market contracts	697				697
Other long-term obligations	375	30	66		471
Total non-current liabilities	7,557	717	9,282	(5,834)	11,722
Total liabilities	8,134	1,138	10,176	(6,116)	13,332
Minority interest		1			1
3.625% Preferred stock			247		247
Stockholders Equity	9,986	440	5,624	(10,426)	5,624
Total Liabilities and Stockholders Equity	$ 18,120	$ 1,579	$ 16,047	$ (16,542)	$ 19,204

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

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NRG Energy, Inc. and Subsidiaries
Condensed Consolidating Statements of Cash Flows
For the Nine Months Ended September 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	$ 814	$ 68	$ 482	$ (882)	$ 482
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions in excess/(less than) equity earnings of unconsolidated affiliates and consolidated subsidiaries	190	(25)	(466)	278	(23)
Depreciation and amortization of nuclear fuel	502	19	4		525
Amortization of financing costs and debt discount		5	54		59
Amortization of intangibles and out-of-market contracts	(116)	4			(112)
Amortization of stock-based compensation			19		19
Changes in deferred income taxes	63	(40)	209		232
Changes in nuclear decommissioning liability	23				23
Changes in derivatives	41				41
Gain on sale of assets	(16)				(16)
Gain on sale of emission allowances	(31)				(31)
Changes in collateral deposits supporting energy risk management activities	(107)				(107)
Gain on sale of equity method investments		(1)			(1)
Cash provided by/(used by) changes in other working capital, net of dispositions affects	416	54	(585)		(115)
Net Cash Provided by Operating Activities	1,779	84	(283)	(604)	976
Cash Flows from Investing Activities					

Intercompany issuance of notes	(70)			70	
Intercompany receipts on notes			1,182	(1,182)	
Capital expenditures	(299)	(4)	(6)		(309)
Increase in restricted cash		(18)			(18)
Decrease in notes receivable		26			26
Purchases of emission allowances	(152)				(152)
Proceeds from sale of emission allowances	170				170
Proceeds from sale of investments		2			2
Proceeds from sale of assets	29		28		57
Investments in marketable securities			(4)		(4)
Decrease in trust fund balances	19				19
Investments in trust fund securities	(193)				(193)
Proceeds from sales of trust fund securities	170				170
Net Cash Provided/(Used) by Investing Activities	(326)	6	1,200	(1,112)	(232)
Cash Flows from Financing Activities					
Payments for intercompany loans	(1,174)	(38)		1,212	
Receipt for intercompany loans			100	(100)	
Payments from intercompany dividends	(302)	(302)		604	
Payments for dividends to preferred stockholders			(41)		(41)
Payments for treasury stock			(268)		(268)
Proceeds from issuance of long-term debt			1,411		1,411
Payments for deferred financing costs			(5)		(5)
Payments for short and long-term debt	(1)	(36)	(1,435)		(1,472)
Net Cash Used by Financing Activities	(1,477)	(376)	(238)	1,716	(375)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		7			7
Net Increase/(Decrease) in Cash and Cash Equivalent	(24)	(279)	679		376
Cash and Cash Equivalents at Beginning of Period	20	432	343		795
Cash and Cash Equivalents at End of Period	$ (4)	$ 153	$ 1,022	$	$ 1,171

(a) All significant intercompany

transactions have been eliminated in consolidation.

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

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

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

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,846	$ 96	$	$	$ 1,942
Operating Costs and Expenses					
Cost of operations	935	63	(2)		996
Depreciation and amortization	140	7	1		148
General and administrative	19	6	45		70
Development costs	8		1		9
Total operating costs and expenses	1,102	76	45		1,223
Operating Income/(Loss)	744	20	(45)		719
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	94		480	(574)	
Equity in earnings of unconsolidated affiliates	2	15			17
Write downs and losses on sales of equity method investments	(2)	(1)			(3)
Other income, net	(12)	11	36	(5)	30
Interest expense	(34)	(15)	(110)	5	(154)
Total other income/(expense)	48	10	406	(574)	(110)
Income From Continuing Operations Before Income Taxes	792	30	361	(574)	609
Income tax expense/(benefit)	291	10	(63)		238
Income From Continuing Operations	501	20	424	(574)	371
Income from discontinued operations, net of income tax expense		53	(2)		51
Net Income	$ 501	$ 73	$ 422	$ (574)	$ 422

(a)

All significant intercompany transactions have been eliminated in consolidation.

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 4,218	$ 261	$	$	$ 4,479
Operating Costs and Expenses					
Cost of operations	2,298	178	2		2,478
Depreciation and amortization	420	19	4		443
General and administrative	61	11	133		205
Development costs	12		3		15
Total operating costs and expenses	2,791	208	142		3,141
Operating Income/(Loss)	1,427	53	(142)		1,338
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	130		911	(1,041)	
Equity in earnings of unconsolidated affiliates	3	43			46
Write downs and gain/(losses) on sales of equity method investments	(5)	13			8
Other income, net	14	93	26	(15)	118
Refinancing expense			(178)		(178)
Interest expense	(170)	(47)	(218)	15	(420)
Total other income/(expense)	(28)	102	541	(1,041)	(426)
Income From Continuing Operations Before Income Taxes	1,399	155	399	(1,041)	912
Income tax expense/(benefit)	530	44	(250)		324
Income From Continuing Operations	869	111	649	(1,041)	588
Income from discontinued operations, net of income tax expense		61	2		63
Net Income	$ 869	$ 172	$ 651	$ (1,041)	$ 651

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations[a]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 869	$ 172	$ 651	$ (1,041)	$ 651
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions less than equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(133)	(24)	(911)	1,041	(27)
Depreciation and amortization of nuclear fuel	453	30	7		490
Amortization and write-off of financing costs and debt discounts		5	66		71
Amortization of intangibles and out-of-market contracts	(390)	(3)			(393)
Amortization of stock-based compensation			13		13
Write down and (gains)/losses of equity method investments	5	(13)			(8)
Changes in deferred income taxes	430	25	(146)		309
Nuclear decommissioning trust liability	9				9
Loss on sale of equipment	3				3
Changes in derivatives	(190)	1	6		(183)
Gain on legal settlement		(67)			(67)
Gain on sale of discontinued operations		(71)			(71)
Gain on sale of emission allowances	(68)				(68)
Changes in collateral deposit payments supporting of energy risk management activities	397				397
Cash provided/(used) by changes in working capital, net of acquisition and disposition affects	(542)	129	453		40
Net Cash Provided by Operating Activities	843	184	139		1,166

Cash Flows from Investing Activities					
Acquisition of Texas Genco LLC, WCP and Padoma, net of cash acquired			(4,336)		(4,336)
Capital expenditures	(140)	(17)	(2)		(159)
Decrease/(Increase) in restricted cash, net	2	(26)			(24)
Decrease/(Increase) in notes receivable	(922)	22	(3,063)	3,985	22
Purchases of emission allowances	(76)				(76)
Proceeds from sale of emission allowances	97				97
Investments in nuclear decommissioning trust fund securities	(158)				(158)
Proceeds from sales of nuclear decommissioning trust fund securities	149				149
Proceeds from sale of equipment	1				1
Proceeds from sale of investments	53	33			86
Proceeds from sale of discontinued operations		239			239
Net Cash Provided/(Used) by Investing Activities	(994)	251	(7,401)	3,985	(4,159)
Cash Flows from Financing Activities					
Payment of dividends to preferred stockholders			(37)		(37)
Payment of financing element of acquired derivatives	(118)				(118)
Payment for treasury stock		(297)			(297)
Funded letter of credit			350		350
Proceeds from Intercompany loans	3,063		922	(3,985)	
Proceeds from issuance of common stock, net			986		986
Proceeds from issuance of preferred shares, net			486		486
Proceeds from issuance of long-term debt		198	7,175		7,373
Payment of deferred debt issuance costs			(174)		(174)
Payments of short and long-term debt	(2,751)	(42)	(1,904)		(4,697)
Net Cash Provided/(Used) by Financing Activities	194	(141)	7,804	(3,985)	3,872
		14			14

Change in cash from discontinued operations					
Effect of exchange rate changes on cash and cash equivalents		2			2
Net Increase in Cash and Cash Equivalents	43	310	542		895
Cash and Cash Equivalents at Beginning of Period	(7)	78	422		493
Cash and Cash Equivalents at End of Period	$ 36	$ 388	$ 964	$	$ 1,388

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

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

Introduction and Overview

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 select international markets. As of September 30, 2007, NRG had a total global portfolio of 191 active operating generation units at 49 power generation plants, with an aggregate generation capacity of approximately 24,110 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 22,875 MW of generation capacity in 175 active generating units at 43 plants. These power generation facilities are primarily located in Texas (approximately 10,800 MW), the Northeast (approximately 6,980 MW), South Central (approximately 2,850 MW), and West (approximately 2,130 MW) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets. NRG s principal domestic power plants consist of a diversified mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 46%, 33%, 16% and 5% of the Company s total domestic generation capacity, respectively. In addition, 15% of NRG s domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option. NRG s domestic generation facilities primarily consist of baseload, intermediate and peaking power generation facilities, which are referred to as the Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s diverse generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

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

1. ***FOR*NRG** is a companywide initiative, introduced in 2005, and designed to increase the return on invested capital, or ROIC through operational performance improvements to the Company s asset fleet, along with a range of initiatives at plants and at corporate offices to reduce costs or, in some cases, generate revenue. The *FOR*NRG earnings accomplishments disclosed in NRG s SEC filings and press releases are annual, cumulative, recurring improvements measured from the 2004 program inception base data, with the exception of the Texas region which joined the program in 2006 and whose improvements are measured using 2005 as the base year. For plant operations the program measures cumulative current year benefits using current gross margins times the change in baseline levels of certain key performance indicators. The plant performance benefits include both positive and negative results for plant reliability, capacity, heat rate and station service. Recurring improvements in total operating costs and expenses are included in *FOR*NRG savings accomplishments, while non-recurring reductions in operating expenses, working capital and capital expenses are not included, although these benefits are tracked and measured under this program.

2. ***Repowering*NRG** is our program designed to develop, finance, construct and operate new, highly efficient, environmentally responsible capacity over the next decade. In connection with NRG s acquisition of Padoma Wind Power LLC, the Company is actively evaluating domestic terrestrial wind projects as part of the *Repowering*NRG program.

3. **econrg** represents NRG s commitment to environmentally responsible power 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** Respect for the community is one of NRG s core values. Our Global Giving Program invests NRG s resources to strengthen the communities where we do business and seeks to make community investments in four FOCUS areas: community and economic development, education, environment and human welfare.

NRG s 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 Estimates section.

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

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

factors which affect the business;

earnings and costs in the periods presented;

changes in earnings and costs between periods;

sources of earnings;

impact of these factors on NRG s overall financial condition;

expected future expenditures for capital projects; and

expected sources of cash for further operations and capital expenditures.

As you read this discussion and analysis, refer to the consolidated statements of income which present the results of operations for the three and nine months ended September 30, 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.

Environmental Matters

Earlier this year, the U.S. Supreme Court found that CO_2 could be regulated as a pollutant and that the USEPA should regulate CO_2 emissions from mobile sources. In the future, regulation by the USEPA of CO_2 emissions under programs that affect fossil fuel generation could materially impact NRG s operations.

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The Northeast States in the Regional Greenhouse Gas Initiative, or RGGI, as well as California and other Western states are working to move regional and state climate change programs forward. Massachusetts, Maine, Maryland and New York have released draft greenhouse gas rules for comment. RGGI allowance auctions could begin as early as July 2008. Emissions in 2006 for NRG s generating units subject to RGGI were approximately 13 million tons of CO_2. NRG continues to explore strategies to minimize CO_2 emissions at subject plants and to obtain allowances and offsets.

At the national level, climate change and the need for regulation of GHG emissions is being debated by the public, Congress and the Bush Administration. NRG continues to advocate for sound, national legislation to reduce GHG emissions. NRG also seeks to move forward with *Repowering*NRG initiatives that the Company anticipates will result in long-term GHG intensity reductions, evaluate options for control and sequestration of CO_2 from power plants, and review other opportunities for power generation with no or low CO_2 emissions. NRG supports development of new technologies to reduce CO_2 through such investments as the use of algae for uptake of power plant emissions, piloting of backend controls for capture from stacks and underground sequestration.

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.

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

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Consolidated Results of Operations

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

	Three months ended September 30			Nine months ended September 30		
(In millions except otherwise noted)	**2007**	**2006**	**Change %**	**2007**	**2006**	**Change %**
Operating Revenues						
Energy revenue	$ 1,278	$ 1,112	15%	$ 3,292	$ 2,467	33%
Capacity revenue	328	430	(24)	890	1,125	(21)
Risk management activities	35	126	(72)	44	162	(73)
Contract amortization	66	223	(70)	185	494	(63)
Thermal revenue	27	28	(4)	97	93	4
Other revenues	52	23	126	136	138	(1)
Total operating revenues	1,786	1,942	(8)	4,644	4,479	4
Operating Costs and Expenses						
Cost of operations	943	996	(5)	2,570	2,478	4
Depreciation and amortization	161	148	9	483	443	9
General and administrative	79	70	13	236	205	15
Development costs	49	9	444	108	15	620
Total operating costs and expenses	1,232	1,223	1	3,397	3,141	8
Gain on sale of assets				16		NA
Operating income	554	719	(23)	1,263	1,338	(6)
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	19	17	12	40	46	(13)
Write downs and gains/(losses) on sales of equity method investments		(3)	NA	1	8	(88)
Other income, net	15	30	(50)	45	118	(62)
Refinancing expenses				(35)	(178)	(80)
Interest expense	(173)	(154)	12	(528)	(420)	26
Total other expenses	(139)	(110)	26	(477)	(426)	12
Income from Continuing Operations before income tax expense	415	609	(32)	786	912	(14)
Income tax expense	147	238	(38)	304	324	(6)
Income from Continuing Operations	268	371	(28)	482	588	(18)
Income from discontinued operations, net of income tax expense		51	NA		63	NA
Net Income	$ 268	$ 422	(36)	$ 482	$ 651	(26)

Business Metrics						
Average natural gas price Henry Hub ($/MMBtu)	6.24	6.14	2%	7.02	6.90	2%

NA Not Applicable

Significant Items Reflected in NRG s Results of Operations during the nine months ended September 30, 2007

- *Impact of Hedge Reset* energy revenue increased by $365 million as the period s average contract prices increased by approximately $15 per MWh as compared to the 2006 average contract prices
- *Development costs* on September 24, 2007, NRG filed a Combined Construction and Operating License Application, or COLA, with the NRC to build and operate two new nuclear units at the STP site. NRG incurred $108 million in development costs due primarily to required engineering studies to obtain the COLA as well as development costs for other *Repowering*NRG projects
- *Acquisition of Texas and WCP* due to the inclusion of the Texas and WCP results for the entire nine month period, operating income increased by approximately $76 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 $55 million
- *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 $108 million

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

Operating Revenues

Operating revenues decreased by $156 million during the three months ended September 30, 2007, compared to 2006. This was due to:

Energy revenues energy revenues increased by $166 million during the three months ended September 30, 2007, compared to 2006:

- o *Texas* energy revenues increased by $194 million. Increases include $220 million due to the Hedge Reset as average contracted prices for the period increased by approximately $22 per MWh; and revenues from 2.2 million MWh of generation moving from capacity revenue to energy revenue. 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. Decreases are primarily due to 1.1 million MWh of lower sales from gas units due to the cooler summer as reflected by a decrease of 9% in CDD s, as well as the related reduction of revenue caused by netting out the cost of energy purchased to cover the region s obligations, when buying from the market is more economic than running the generating units.

- o *Northeast* energy revenues decreased by $23 million of which $4 million was due to a 1% decrease in generation with $12 million due to a 4% decrease in average market prices. These decreases were due to lower natural gas prices which drove decreases in average prices in the region s primary markets. Despite the drop in prices, generation at the Arthur Kill plant was up 31% in the quarter largely due to the ongoing effects of transmission constraints in the New York City area which provided for additional dispatch of the plant. Energy revenues were also adversely affected by a $7 million decrease in net revenues from supplying load requirements in PJM.

- o *South Central* energy revenues increased by $24 million, of which $22 million was due to a new baseload contract which became effective January 1, 2007. Energy revenues from the region s cooperative customers also increased by $4 million due to a 3% increase in MWh sold and a higher contractual fuel adjustment charge.

Capacity revenues capacity revenues decreased by $102 million during the three months ended September 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:

- o *Texas* capacity revenues decreased by $144 million due to a reduction in capacity auction sales mandated by the PUCT in prior years.

- o *Northeast* capacity revenues increased by $28 million due to increased capacity revenues in NEPOOL from LFRM of $8 million, net transition payments of $3 million and $5 million in higher RMR payments with Norwalk s RMR agreement effective June 19, 2007. Increased capacity revenues from PJM from the new RPM market of $18 million were partially offset by lower capacity revenues in New York of $6 million as the region realized capacity prices that were lower than those attained during 2006.

- o *South Central* capacity revenues increased by approximately $5 million, of which $2 million was attributable to higher billing rates as a result of the region s market setting a new summer peak in 2006, with an additional $2 million due to the contractual pass-through of higher transmission costs. The new baseload contract also contributed $2 million to capacity revenues.

- o *West* new tolling agreements at the region s Long Beach and Encina plants increased capacity revenues by approximately $8 million. On August 1, NRG successfully completed the repowering of a 260 MW gas-fired generating plant at its Long Beach generating facility, which contributed approximately $5 million in capacity revenues for the three months ended September 30, 2007.

Contract amortization revenues from contract amortization decreased by $157 million during the three months ended September 30, 2007, compared to 2006. This was due to the Hedge Reset transaction, which resulted in the write-off of a large portion of the Company s out-of-market power contracts in November 2006.

Other revenues other revenues increased by $29 million during the three months ended September 30, 2007 compared to 2006 due to:

- *Trading of natural gas* physical natural gas sales increased by approximately $18 million, primarily due to increased third party sales as a result of the sale of excess natural gas.

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- o *Sale of emission allowances* net sales of emission allowances increased by $7 million during the period of which $5 million was related to SO_2 emission sales. 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.

- o *Ancillary revenues* ancillary services revenue increased by approximately $5 million primarily due to a change in strategy which increased the Company s participation in the ancillary services market in the Texas region.

Risk management activities revenues from risk management activities include all derivative activity that do not qualify for hedge accounting as well as the ineffective portion associated with hedged transactions. Such revenues were $35 million for the three months ended September 30, 2007, and $126 million for the three months ended September 30, 2006. The breakdown of changes by region are as follows:

	Three months ended September 30, 2007				**Three months ended September 30, 2006**				
(In millions)	**Texas**	**Northeast**	**South Central**	**Total**	**Texas**	**Northeast**	**South Central**	**All Other**	**Total**
Net gains/(losses) on settled positions, or financial revenues	$ 15	$ 13	$ 1	$ 29	$ (44)	$ (7)	$ (3)	$ (3)	$ (57)
Mark-to-market results									
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	(15)	(2)		(17)		37			37
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	(1)	3	(5)	(3)		1			1
Net unrealized gains/(losses) on open positions related to economic hedges	1	9		10	128	35	(2)		161
Net unrealized gains/(losses) on open positions related to trading	(4)	5	15	16		(33)	17		(16)

activity									
Subtotal mark-to-market results	(19)	15	10	6	128	40	15		183
Total derivative gain/(losses)	$ (4)	$ 28	$ 11	$ 35	$ 84	$ 33	$ 12	$ (3)	$ 126

NRG s third quarter 2007 derivative gain was comprised of $6 million of mark-to-market gains and $29 million in settled gains, or financial revenue. Of the $6 million of mark-to-market gains, $17 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $3 million from the reversal of mark-to-market gains previously recognized on trading activity. Both of these gains ultimately settled as financial revenues during the third quarter 2007. A $10 million gain from economic hedge positions was comprised of a $1 million increase in the value of forward sales of electricity and fuel due to favorable power and natural gas prices and a $9 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 between natural gas and power prices.

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 and cost of energy.

Cost of Operations

Cost of operations for the three months ended September 30, 2007, decreased by $53 million compared to 2006; however, as a percentage of revenues it increased to 53% in 2007 compared to 51% in 2006:

Cost of energy cost of energy decreased by approximately $63 million, to $737 million, during the three month period ended September 30, 2007, compared to 2006. This decrease was due to:

- o *Texas* decreased by approximately $48 million. Of this decrease, $66 million was due to a 33% decrease in gas-fired generation largely because of milder weather and increased economic purchases from ERCOT. In addition, coal expense decreased by $9 million due to lower generation and reduced contract prices. Generation decreased by 119,000 MWH due to forced outages at the region s Limestone and W.A. Parish plants. These decreases were partially offset by an $18 million increase in purchased power due to forced outages at the region s W.A. Parish and Limestone plants in 2007 and a $9 million increase in ancillary service expense due to favorable market prices in purchasing this service in the market compared to providing the service from internal resources causing an associated decrease in natural gas expense.

- o *Northeast* decreased by $11 million for the three months ended September 30, 2007 as compared to 2006, following lower fuel oil costs of approximately $26 million due to lower generation from the region s oil-fired assets as it was not economical to dispatch from the region s oil plants. This was partially offset by higher natural gas expense of approximately $14 million due to increased generation from the region s New York City plants.

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- o *South Central* cost of energy increased by $28 million due to a new baseload contract, a 3% increase in the region s cooperative load requirements as well as higher coal and transmission costs. Of this increase, $17 million was from an increase in purchased energy due to heavier reliance on the region s tolling agreements to support load requirements and merchant sales during the third quarter 2007 as compared to 2006. Coal costs increased by $4 million which was driven by a 4% increase in coal generation at the region s Big Cajun II plant due to higher energy demand. In addition, transmission costs also increased by $4 million of which $2 million was related to contractual increases for network service with the remaining $2 million related to the new baseload contract.

Other operating costs Other operating costs increased by $10 million, to $206 million, during the three months ended September 30, 2007, compared to 2006. This increase was due to $5 million in higher operational labor costs and increased remediation costs in the Northeast region and $3 million due to increased in operations and maintenance, or O&M, expense in the South Central region. Also contributing was higher O&M and property tax expense of approximately $3 million in the Texas region.

Depreciation and Amortization

NRG s depreciation and amortization expense for the three months ended September 30, 2007, increased by $13 million compared to 2006. This increase was due to the use of estimates during 2006 prior to the final purchase price allocation related to the acquisition to the Company s Texas assets.

General and Administrative

NRG s general and administrative, or G&A, costs for the three months ended September 30, 2007, increased by $9 million compared to 2006, however as a percentage of revenues it was flat at 4% for both periods. This increase was primarily due to higher wage and benefit costs.

Development Costs

NRG s development costs were approximately $40 million higher for the three months ended September 30, 2007, compared to same period in 2006. These costs were due to the Company s *Repowering*NRG projects:

Texas on September 24, 2007, NRG filed a COLA with the NRC to build and operate two new nuclear units at the STP site. During the quarter, NRG incurred $34 million in development costs for required engineering studies to obtain the COLA.

Wind projects approximately $5 million of the increase in development costs was related to wind projects primarily in Texas.

Other project development costs related to other *Repowering*NRG projects primarily in the Northeast and West regions accounted for the remaining increase.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates for the three months ended September 30, 2007, increased by $2 million compared to 2006. This increase was primarily due to higher coal sales and power at MIBRAG which contributed approximately $5 million. This was offset by a $3 million reduction in equity earnings due to the sale of certain equity method investments in 2006.

Interest Expense

NRG s interest expense for the three months ended September 30, 2007, increased by $19 million compared to 2006. This increase was due to:

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

Capital Allocation Program the Company issued a total of $330 million of debt to fund Phase I of the Capital Allocation Program during the latter half of the third quarter 2006, increasing interest expense by $6 million.

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 SFAS 133, and the impact associated with ineffectiveness was immaterial to NRG s financial results. For the three months ended September 30, 2007, NRG had deferred a loss of $29 million in other comprehensive income compared to a deferred loss of $65 million in 2006.

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Income Tax Expense

Income tax expense decreased by $91 million during the three months ended September 30, 2007, compared to 2006. The effective tax rate was 35.4% and 39.1% for the three months ended September 30, 2007 and 2006, respectively. The decrease in tax expense was primarily due to a reduction in income, coupled with the impact of a German tax rate change.

Decrease in profits - income before tax decreased by $194 million, with a corresponding decrease of approximately $77 million in tax expense.

Permanent differences the Company s effective tax rate differs from the US statutory rate of 35% due to:

- o *Change in German tax rate* due to a reduction in the German statutory and resulting effective tax rate, income tax expense benefited by $30 million during the third quarter 2007.

- o *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 income tax expense of approximately $12 million.

- o *Lower tax rates in foreign jurisdictions* lower income tax rates at the Company s foreign locations benefited the Company during 2006 by an additional $4 million compared to 2007.

- o *Non-deductible interest* interest expense from the stock buybacks from Phase I of the Company s Capital Allocation Program are non-deductible for income tax purposes, thus increasing income tax expense by approximately $2 million.

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in 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 nine months ended September 30, 2007 and 2006

Operating Revenues

Operating revenues increased by $165 million during the nine months ended September 30, 2007, compared to 2006. This was due to:

Energy revenues energy revenues increased by $825 million during the nine months ended September 30, 2007, compared to 2006:

- o *Texas* energy revenues increased by $731 million of which $217 million was due to the inclusion of nine months activity in 2007 compared to eight months in 2006. Of this increase, $365 million was due to the Hedge Reset transaction which resulted in higher 2007 average contracted prices by approximately $15 per MWh. In addition, revenues from 6.9 million MWh of generation moved from capacity revenue to energy revenue. 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. Decreases include 2.5 million MWh of lower sales from gas units due to the cooler summer as reflected by a decrease of 16% in CDD s, as well as the related reduction of revenue caused by netting out the cost of energy purchased to cover the region s obligations, when buying from the market is more economic than running the generating units.

- o *Northeast* energy revenues increased by approximately $82 million, of which $42 million was due to a 6% increase in generation, primarily driven by increases at the region s Arthur Kill, Oswego and Indian River plants. The Arthur Kill plant increased generation by 342 thousand MWh due to transmission constraints around New York City, the Oswego plants generation increased by 95 thousand MWh due to a colder winter during 2007 compared to 2006, and Indian River plants generation increased by 230 thousand MWh coming off weak pricing and generation in the third quarter 2006. In addition, $35 million was due to a 5% increase in average market prices per MWh in the region.

- *South Central* energy revenues increased by approximately $62 million due to a new baseload contract which contributed approximately $53 million to energy contract revenues, increasing contract sales volume by approximately 1 million MWh. Following a contractual fuel adjustment charge, energy revenues increased by $10 million from the region s cooperative customers.

- *West* energy revenues decreased by approximately $55 million, excluding the first quarter 2007, primarily due to the tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment in return for the right to schedule and dispatch from the plant.

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Capacity revenues capacity revenues decreased by $235 million during the nine months ended September 30, 2007, compared to 2006, primarily 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 $351 million despite the inclusion of nine months activity in 2007 compared to eight months in 2006. This decrease was due to a reduction of capacity auction sales mandated by the PUCT in prior years as previously discussed.

- *Northeast* capacity revenues increased by $55 million $30 million of the increase was from the region s s NEPOOL assets and $22 million was from the region s PJM assets. The NEPOOL assets benefited from the new LFRM market and transition capacity market, both introduced in the fourth quarter 2006. Capacity revenues increased by $25 million from the LFRM market and $16 million from transition capacity payments, which was offset by an $11 million reduction in capacity payments due to the expiration of the Devon plant s RMR agreement on December 31, 2006. On June 1, 2007, the new RPM capacity market became effective in PJM increasing capacity revenues by $22 million as compared to the first nine months of 2006.

- *South Central* capacity revenues increased by approximately $15 million. Of this increase, $6 million was due to higher billing rates as a result of the region s market setting a new summer peak hit in 2006, higher contractual transmission pass-though costs to the cooperative customers also contributed $5 million and $2 million in higher merchant revenues from the region s Rockford plants due to improved market conditions. In August 2007, the region set a new system peak of 2,123 MW which will impact capacity revenue over the next year.

- *West* capacity revenues increased by approximately $40 million, of which $26 million was related to the inclusion of the first quarter 2007 compared to 2006. New tolling agreements at the region s Encina and Long Beach plants, accounted for the remaining difference with the Encina facility contributing approximately $8 million and the newly-repowered Long Beach facility contributing $5 million.

Contract amortization revenues from contract amortization decreased by $309 million during the nine months ended September 30, 2007, compared to 2006, as a result of $31 million of amortization of in-the-market power contracts acquired with Texas Genco LLC that were fully amortized in 2006 and 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.

Other revenues other revenues decreased by $2 million during the nine months ended September 30, 2007, compared to 2006 due to:

- *Ancillary revenues* ancillary services revenue increased by approximately $18 million due to a change in strategy to actively provide ancillary services in the Texas region which increased revenues by $28 million. This was partially offset by a $6 million reduction in ancillary services in the Northeast region due to higher transmission costs following transmission constraints in the New York City area.

- *Sale of emission allowances* net sales of SO_2 emission allowances decreased by approximately $41 million due to increased generation and a decrease in sales activity following a 36% reduction in average market prices.

- *Physical gas sales* increased by $17 million due to the sale of excess natural gas.

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 were $44 million for the nine months ended September 30, 2007 and $162 million for the nine months ended September 30, 2006. The breakdown of changes by region are as follows:

(In millions)	Nine months ended September 30, 2007 Texas	Northeast	South Central	Total	Nine months ended September 30, 2006 Texas (a)	Northeast	South Central	All Other	Total
Net gains/(losses) on settled positions, or financial revenues	$ 31	$ 49	$ 5	$ 85	$ (117)	$ (19)	$ 1	$ (3)	$ (138)
Mark-to-market results									
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	(69)	(40)		(109)		101	1		102
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity		(9)	(14)	(23)		(25)	(1)		(26)
Net unrealized gains/(losses) on open positions related to economic hedges	39	15		54	179	32	(2)	(1)	208
Net unrealized gains/(loses) on open positions related to trading activity	1	8	28	37		(1)	17		16
Subtotal mark-to-market results	(29)	(26)	14	(41)	179	107	15	(1)	300
Total derivative gain/(losses)	$ 2	$ 23	$ 19	$ 44	$ 62	$ 88	$ 16	$ (4)	$ 162

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

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NRG s 2007 derivative gain was comprised of $41 million of mark-to-market losses and $85 million in settled gains, or financial revenue. Of the $41 million of mark-to-market losses, $109 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $23 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 $54 million gain from economic hedge positions was comprised of a $23 million increase in the value of forward sales of electricity and fuel due to favorable power and gas prices and a $31 million gain from hedge accounting ineffectiveness. This ineffectiveness was primarily related to gas swaps and collars in the Texas region due to a change in the correlation between natural gas and power prices.

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 and cost of energy.

Cost of Operations

Cost of operations for the nine months ended September 30, 2007, increased by $92 million compared to 2006, but as a percentage of revenues it was 55% for both nine month periods ended September 30, 2007 and 2006.

Cost of energy cost of energy decreased by approximately $9 million, to $1,880 million, during the first nine months of 2007 as compared to 2006, and as a percentage of revenue it decreased from 42% for the nine months ended September 30, 2006 to 40% for the nine months ended September 30, 2007. This decrease was due to:

- *Texas* decreased by $61 million during the nine months ended September 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 $157 million. This decrease was due to a reduction in natural gas expense, purchased power and fuel contract amortization, partially offset by increased ancillary service expense.

  Fuel expense and Purchased Power expense Natural gas expense decreased by $121 million including January 2007 of $27 million due to a decrease of 2.5 million MWh in gas-fired generation as a result of cooler summer weather, coupled with greater economic purchases from ERCOT and increased baseload generation. Coal expenses excluding January 2007, also decreased by $6 million due to an 6% reduction in average contracted coal prices, despite higher coal-fired generation at the region s W.A. Parish and Limestone plants. Purchased power expense decreased by $5 million due to forced outages in 2006 at the region s W.A. Parish and Limestone plants.

  Amortized fuel costs decreased by approximately $18 million due to fuel price curves being below the contracted prices at acquisition in February 2006.

  Purchased ancillary service expense increased by approximately $24 million due to the favorable market prices in purchasing this service in the market compared to providing the service from internal resources.

- *Northeast* cost of energy increased by $24 million due to an increase in natural gas costs, offset by lower emission amortization and coal costs.

  Natural gas costs increased by approximately $34 million as a result of increased generation primarily at the region s Arthur Kill plant due to its locational advantage to New York City following transmission constraints during the second and third quarter of 2007.

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

  Coal costs despite increased generation of 245 thousand MWh at the region s coal-fired plants, coal costs decreased by $4 million due to a 4% decrease in average contracted prices of purchased coal.

- *South Central* Cost of energy increased by $74 million due to increases in purchased energy, coal costs and transmission costs.

Purchased energy increased by approximately $46 million due to increased market purchases following increased cooperative load requirements and planned maintenance at the region s Big Cajun II facility.

Coal costs increased by approximately $15 million, of which $8 million was related to a 6% increase in coal prices and $3 million due to higher coal consumption.

Transmission costs increased by approximately $12 million of which $4 million was due to contractual increases related to network transmission service. Point-to-point transmission costs also increased by $8 million reflecting more off-system sales.

- o *West* Cost of energy decreased by approximately $56 million, excluding the first quarter 2007, due to the new tolling agreement entered into at the Encina plant in 2007, which requires the counterparty to supply their own fuel.

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Other operating costs Other operating costs increased by $101 million, to $690 million, during the nine months ended September 30, 2007, compared to 2006. This increase was due to:

- *Texas* other operating costs increased by $55 million, however, when excluding the January 2007 expense of $39 million, other operating costs increased by $16 million. This increase was due to a refueling outage at STP which increased maintenance expense by approximately $16 million which was partially offset by reduced maintenance at the region s coal-fired plants of approximately $7 million because of reduced planned outage time in 2007.

- *Northeast* other operating costs increased by $18 million primarily 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.

- *South Central* other operating costs increased by approximately $12 million primarily due to an increased maintenance expense of approximately $7 million for planned outages.

- *Acquisition of WCP* these results include $15 million of WCP expenses that were not included in the Company s results in 2006, as well as $7 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 nine months ended September 30, 2007, increased by $40 million compared to 2006. This increase was due to:

Texas acquisition the inclusion of Texas results for nine months in 2007 compared to eight months in 2006 resulted in an increase of approximately $32 million.

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 equipment to reflect the remaining useful life, resulting in increased depreciation of approximately $8 million.

General and Administrative

NRG s G&A costs for the nine months ended September 30, 2007, increased by $31 million compared to 2006, and as a percentage of revenues was 5% in both 2007 and 2006. This increase was due to:

Texas acquisition the inclusion of Texas results for nine months in 2007 compared to eight months in 2006 resulted in an increase of approximately $8 million.

Wage and benefit costs due to the expansion of the Company including *Repowering*NRG initiatives, wages and related benefits costs resulted in a $24 million increase in G&A.

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

Non-recurring expenses during 2006 for the nine months ended September 30, 2006, G&A included non-recurring fees of $17 million of which $6 million were related to the unsolicited takeover attempt by Mirant Corporation and $11 million associated with the Texas integration efforts.

Development Costs

NRG s development costs for the nine months ended September 30, 2007, increased by $93 million. These costs were due to the Company s *Repowering*NRG projects:

Texas on September 24, 2007, NRG filed a COLA with the NRC to build and operate two new nuclear units at the STP site. During the period, NRG incurred $75 million in development costs for required engineering studies to obtain the COLA.

Wind projects approximately $12 million in development costs related to wind projects primarily in Texas.

Other project approximately $6 million in development costs related to other *Repowering*NRG projects in the Northeast and West regions.

Gain on Sale of Assets

NRG s net gain on sale of assets for the nine months ended September 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.

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Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates for the nine months ended September 30, 2007, decreased by $6 million compared to 2006. This decrease was primarily due to the sale of multiple equity investments from which the Company earned $8 million for the nine months ended September 30, 2006.

Other Income, Net

NRG s other income for the nine months ended September 30, 2007, decreased by $73 million compared to 2006. This decrease was due to the non-cash settlement during the first quarter 2006 where NRG recorded $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.

Interest Expense

NRG s interest expense for the nine months ended September 30, 2007, increased by $108 million compared to 2006. This increase was due to:

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 approximately $34 million compared to 2006.

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 $61 million.

Capital Allocation Program the Company issued a total of $330 million of debt to fund Phase I of the Capital Allocation Program during the second half of 2006. This increased interest expense by $20 million compared to 2006.

Change from Credit Facility The payment of $400 million in the Company s Term B loan reduced interest expense by approximately $14 million which was offset by an increase in interest expense from letters of credit issued of 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 SFAS 133, and the impact associated with ineffectiveness was immaterial to NRG financial results. For the nine months ended September 30, 2007, NRG had deferred a loss of $15 million in other comprehensive income compared to deferred gains of $9 million in 2006.

Refinancing Expense

Refinancing expense decreased by $143 million during the nine months ended September 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 Company 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 decreased by $20 million during the nine months ended September 30, 2007, compared to 2006. The effective income tax rate was 38.7% and 35.5% for the nine months ended September 30, 2007 and 2006, respectively. The decrease in income tax expense was due to a decrease in profits and the effect from the change in German statutory and resulting effective tax rate, which were partially offset by an increase in other permanent differences:

Decreased profits income before tax decreased by $126 million with a corresponding decrease of approximately $49 million in income tax expense.

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Permanent differences:

- *Change in German tax rate* due to a reduction in the German statutory and resulting effective tax rate, income tax expense benefited by $30 million during the third quarter 2007.
- *Disputed claims reserve* During 2006, the Company made distributions from its disputed claims reserve decreasing 2006 income tax expense by approximately $29 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 income tax expense of approximately $19 million.
- *Lower tax rates in foreign jurisdictions* lower income tax rates at the Company s foreign locations benefited the Company during 2006 by an additional $14 million compared to 2007.
- *Non-deductible interest* interest expense from the stock buybacks from Phase I of the Company s Capital Allocation Program are non-deductible for income tax purposes, thus increasing the Company s income tax expense by approximately $7 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 changes in 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 $63 million during the nine months ended September 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 $60 million and $11 million due to the after tax gain from the sale of Flinders and Audrain, respectively. These gains were offset by a loss from their operations of approximately $8 million.

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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 Form 10-K.

Selected income Statement data

(In millions except otherwise noted)	Three months ended September 30 2007	Three months ended September 30 2006	Change%	Nine months ended September 30 [(b)] 2007	Nine months ended September 30 [(b)] 2006	Change %
Operating Revenues						
Energy revenue	$ 803	$ 609	32	$ 2,053	$ 1,322	55
Capacity revenue	90	234	(62)	273	624	(56)
Risk management activities	(4)	84	NA	2	62	(97)
Contract amortization	59	218	(73)	167	481	(65)
Other revenues	8	6	33	31	9	244
Total operating revenues	956	1,151	(17)	2,526	2,498	1
Operating Costs and Expenses						
Cost of energy	358	406	(12)	905	966	(6)
Other operating expenses	175	129	36	527	365	44
Depreciation and amortization	113	104	9	341	309	10
Operating income	$ 310	$ 512	(39)	$ 753	$ 858	(12)
MWh sold (in thousands)	13,792	14,571	(5)	37,037	34,624	7
MWh generated (in thousands)	13,420	14,477	(7)	36,157	33,585	8
Business Metrics						
Average on-peak market power prices ($/MWh)	62.44	71.56	(13)	63.60	66.08	(4)
Cooling Degree Days, or CDDs[(a)]	1,458	1,598	(9)	2,380	2,824	(16)
CDD s 30 year rolling average	1,485	1,485		2,434	2,434	
Heating Degree Days, or HDDs[(a)]		2	NA	1,280	845	51
HDD s 30 year rolling average	5	5		1,208	1,208	

(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 September 30, 2006.*

Quarterly Results

Operating Income

For the three months ended September 30, 2007, compared to 2006, operating income decreased by $202 million due to:

Contract Amortization reduction of approximately $159 million, due to the Hedge Reset transaction, which resulted in the write-off of a large portion of the region s out-of-market power contracts in November 2006.

Capacity to Energy Revenues reduction in capacity revenue of approximately $144 million, with a corresponding increase in merchant energy revenue from moving generation of 2.2 million MWh from capacity revenue to energy revenue.

Lower Gas-fired Generation of 1.1 million MWh was a result of cooler weather and increased economic purchases of energy and ancillary services from ERCOT. Lower sales revenue was largely offset by lower gas fuel costs of $66 million and cash flow hedge improvements.

Development costs as part of *Repowering*NRG, development costs increased by $34 million due to development expenses related to the STP nuclear unit 3 and 4 project.

Solid Fuel Generation Availability planned and forced outages at the Limestone and W.A. Parish plants resulted in an increase in purchased power of approximately $18 million offset by lower coal expense of $9 million.

Hedge Reset increased the Texas region s energy revenues by approximately $220 million as the period s average contract price of the underlying power contracts increased by $22 per MWh as compared to the contract prices in 2006.

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Operating Revenues

Total operating revenues from the Texas region decreased by $195 million during the three months ended September 30, 2007, compared to 2006, due to:

Energy revenues energy revenues increased by $194 million. Increases include $220 million due to the Hedge Reset as average contracted prices for the period increased by approximately $22 per MWh; and revenues from 2.2 million MWh of generation moving from capacity revenue to energy revenue. 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. Decreases are primarily due to 1.1 million MWh of lower sales from gas units following the cooler summer as reflected by a decrease of 9% in CDD s, as well as the related reduction of revenue caused by netting out the cost of energy purchased to cover the region s obligations, when buying from the market is more economic than running the generating units.

Capacity revenues capacity revenues decreased by $144 million due to the reduction in capacity auction sales mandated by the PUCT in prior years.

Contract amortization the Hedge Reset transaction reduced contract amortization revenues by approximately $167 million.

Other revenues the region s revenues from ancillary services increased by approximately $9 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 A loss of $4 million in risk management activities compared to gains of $84 million in 2006. The $4 million loss was comprised of $19 million in losses on derivative revenues which were offset by $15 million in gains on financial revenues. Derivative revenue losses for the three months ended September 30, 2007 included $14 million loss on economic hedges and a $5 million loss in trading activity.

Cost of Energy

Cost of energy for the Texas region decreased by $48 million during the three months ended September 30, 2007, compared to 2006, due to:

Natural gas costs decreased by approximately $66 million due to a 1.1 million MWh decrease in gas-fired generation following milder weather reflected by a 9% decrease in CDD s for the period, coupled with increased economic purchases from ERCOT for both energy and ancillary services when the cost is cheaper than self providing.

Amortized fuel costs decreased by approximately $9 million due to fuel price curves being below the contracted prices at acquisition in February 2006.

This was partially offset by:

Solid Fuel Generation Availability purchased power increased by $18 million due to unplanned outages at the region s W.A. Parish and Limestone plants in 2007 offset by lower coal expense of $9 million due to lower generation and reduced contracted prices. As a result of cooler summer weather and planned and forced outages at the region s Limestone and W.A. Parish plants, coal baseload generation decreased by approximately 119,000 MWh.

Purchased ancillary service expense increased by $9 million due to favorable market prices in purchasing this service in the market compared to providing the service from internal resources causing an associated decrease in natural gas expense.

Other Operating Expenses

Other operating expenses for the Texas region increased by $46 million during the three months ended September 30, 2007, compared to 2006. This was due to:

Development costs on September 24, 2007, NRG filed a COLA with the NRC. NRG incurred $34 million in development costs for the required engineering studies during the quarter.

Planned outages O&M expense decreased by $3 million. Higher coal-fired and gas-fired plant maintenance of $4 million coupled with the resolution of a collective bargaining agreement that included a $3 million charge, was offset by the $9 million planned refueling outage at STP that occurred in the fall of 2006.

Corporate Allocations increased by $6 million compared to the third quarter of 2006.

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Year-to-date Results

Operating Income

For the nine months ended September 30, 2007, operating income decreased by $105 million when compared to 2006, and excluding January 2007 results, operating income decreased by $172 million. The primary drivers are:

Contract Amortization the Hedge Reset transaction reduced contract amortization by approximately $400 million, excluding January 2007.

Capacity Revenues reduction in capacity auction sales reduced capacity revenues by approximately $382 million, excluding January 2007.

Lower Gas-fired Generation of 2.5 million MWh was a result of cooler weather as reflected by a 16% reduction in CDD s coupled with increased economic purchases of energy and ancillary services from ERCOT. Lower sales revenue was offset by lower gas fuel costs of $121 million and cash flow economic hedge improvements.

Development Costs increased by $75 million in 2007 compared to the nine months of 2006 due to development of STP nuclear units 3 and 4 project.

Hedge Reset for the nine months ended September 30, 2007, the Hedge Reset transaction increased the region s energy revenues by approximately $365 million as the average price of the underlying power contracts increased by $15 per MWh as compared to average power contract prices during 2006.

Operating Revenues

Total operating revenues from the Texas region increased by $28 million during the nine months ended September 30, 2007, compared to 2006, and excluding January 2007, they decreased by $227 million. This was due to:

Energy revenues energy revenues increased by $731 million of which $217 million was due to the inclusion of nine months activity in 2007 compared to eight months in 2006. Of the remaining increase, $365 million was due to the Hedge Reset transaction which resulted in higher 2007 average contracted prices by approximately $15 per MWh. In addition, revenues from 6.9 million MWh of generation moved from capacity revenue to energy revenue. 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. Decreases are primarily due to 2.5 million MWh of lower sales from gas units due to the cooler summer as reflected by a decrease of 16% in CDD s, as well as the related reduction of revenue caused by netting out the cost of energy purchased to cover the region s obligations, when buying from the market is more economic than running the units.

Other revenues the region s revenues from ancillary services increased by approximately $28 million due to a change in strategy to actively provide ancillary services in the Texas region.

Capacity revenues capacity revenues decreased by $351 million of which $31 million was incurred in January 2007. This decrease is due to the reduction of capacity auction sales mandated by the PUCT in prior years as described above.

Contract amortization revenues from contract amortization excluding January 2007 decreased by $400 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 power contracts during the fourth quarter 2006 related to the Hedge Reset transaction.

Risk Management Activities gains of $2 million in risk management activities compared to gains of $62 million in 2006. The $2 million gain was comprised of $29 million in losses on derivative revenues which were offset by $31 million in gains on financial revenues.

Cost of Energy

Cost of energy for the Texas region decreased by $61 million during the nine months ended September 30, 2007, compared to 2006. This included an additional month s expense for January 2007 of $96 million, without which cost of energy would have decreased by $157 million. This was due to:

Fuel expense natural gas expense decreased by $121 million, including January 2007 of $27 million due to a decrease of 2.5 million MWh in gas-fired generation as a result of cooler summer weather, coupled with greater economic purchases of energy and ancillary services from ERCOT and increased baseload generation. Coal expenses, excluding January 2007, decreased by $6 million due to a 6% reduction in average contracted coal prices, despite an approximately 1.0 million MWh increase in coal-fired generation at the region s W.A. Parish and Limestone plants.

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- *Purchased ancillary service* increased by approximately $24 million due to the favorable market prices in purchasing this service in the market compared to providing the service from internal resources causing an associated decrease in natural gas expense.
- *Amortized fuel costs* decreased by approximately $18 million due to fuel price curves being below the contracted prices at acquisition in February 2006.

Other Operating Expenses

Other operating expenses for the Texas region increased by $162 million during the nine months ended September 30, 2007 compared to 2006. This included an additional month s expense for January 2007 of $53 million, without which other operating expenses would have increased by $109 million. This was due to:

- *Development costs* on September 24, 2007, NRG filed a COLA with the NRC. NRG incurred $75 million in development costs for the required engineering studies.
- *Increase in O&M expense* O&M expense increased by $11 million excluding January 2007, due to the Spring 2007 STP refueling outage that cost $16 million which was offset by $7 million in lower maintenance costs at the region s coal-fired plants because of reduced planned outage time in 2007.
- *Higher corporate allocations* of approximately $11 million.

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Northeast Region

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

Selected income statement data

(In millions except otherwise noted)	Three months ended September 30, 2007	2006	Change %	Nine months ended September 30, 2007	2006	Change %
Operating Revenues						
Energy revenue	$ 319	$ 342	(7)	$ 845	$ 763	11
Capacity revenue	126	98	29	302	247	22
Risk management activities	28	33	(15)	23	88	(74)
Other revenues	29	5	480	69	98	(30)
Total operating revenues	502	478	5	1,239	1,196	4
Operating Costs and Expenses						
Cost of energy	199	210	(5)	506	482	5
Other operating expenses	92	87	6	298	272	10
Depreciation and amortization	25	22	14	74	66	12
Operating income	$ 186	$ 159	17	$ 361	$ 376	(4)
MWh sold (in thousands)	4,058	4,095	(1)	10,754	10,176	6
MWh generated (in thousands)	4,058	4,095	(1)	10,754	10,176	6
Business Metrics						
Average on-peak market power prices ($/MWh)	78.28	77.44	1	75.89	70.34	8
Cooling Degree Days, or CDDs[(a)]	1,021	1,022		1,343	1,300	3
CDD s 30 year rolling average	859	859		1,068	1,068	
Heating Degree Days, or HDDs[(a)]	243	316	(23)	8,078	7,228	12
HDD s 30 year rolling average	317	317		8,186	8,186	

(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 $27 million for the three months ended September 30, 2007, as compared to 2006, due to:

Operating revenues increased by approximately $24 million due to higher capacity revenues from the newly created LFRM, RPM and transition capacity markets.

Cost of energy decreased by approximately $11 million due to decreased generation at the region s oil-fired plants reducing oil costs by $26 million partially offset by a $14 million increase in natural gas expense following a 25% increase in natural gas-fired generation during the quarter at the region s New York City plants.

Other operating expenses increased by approximately $5 million due to higher staffing costs and increased environmental remediation costs.

Operating Revenues

Operating revenues increased by $24 million for the three months ended September 30, 2007, as compared to 2006, due to:

- *Capacity revenues* increased by $28 million due to increased capacity revenues in NEPOOL from LFRM of $8 million, net transition payments of $3 million and $5 million in higher RMR payments with Norwalk s RMR agreement effective June 19, 2007. Increased capacity revenues from PJM from the new RPM market of $18 million were offset by lower capacity revenues in New York of $6 million as the region realized capacity prices that were lower than those attained during 2006.
- *Other revenues* increased by $24 million of which approximately $27 million was due to excess natural gas available for sale to third parties.

These were partially offset by:

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- *Energy revenues* decreased by $23 million, of which $4 million was due to a 1% decrease in generation, $12 million was due a 4% decrease in the region s average market prices following a decrease in natural gas prices and a $7 million decrease as a result of supplying load requirements to PJM. Despite the drop in power prices, generation at the Arthur Kill plant was up 31% in the quarter due to the ongoing effects of transmission constraints in the New York City area which provided the additional dispatch of the plant. Generation at the region s Indian River plant increased 32% in the quarter against an unusually weak third quarter 2006 production.
- *Risk management activities* of approximately $28 million gains during 2007 compared to $33 million gains in 2006. The $28 million gain includes a $15 million unrealized gain related to changes in the fair value of forward derivative positions compared to a gain of $40 million in the same period in 2006. Risk management revenues also included the value of settled power positions of $13 million in gains compared to a $7 million loss in 2006.

Cost of Energy

Cost of energy decreased by $11 million for the three months ended September 30, 2007, compared to 2006, due to lower fuel oil costs of approximately $26 million following a reduction in generation from the region s oil-fired assets, particularly in NEPOOL, partially offset by higher natural gas costs of approximately $14 million due to increased generation from the region s New York City plants.

Other Operating Expenses

Other operating expenses increased by $5 million for the three months ended September 30, 2007, compared to 2006, due to higher staffing costs, and increased environmental remediation spending.

This was partially offset by:

- *Maintenance expense* decreased by approximately $2 million due to fewer outage activities.
- *Property tax* decreased by approximately $2 million reflecting lower tax assessments at several of the region s power plants.

Year-to-date Results

Operating Income

Operating income decreased by $15 million for the nine months ended September 30, 2007, compared to 2006, due to:

- *Cost of energy* increased by approximately $24 million due to a 6% increase in generation at the region s coal and natural gas-fired plants.
- *Other operating expenses* increased by $26 million primarily 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.
- *Depreciation* increased by $8 million reflecting the additional depreciation expense following the reduction in estimated useful lives of certain components of the region s power plants as a result of new environmental regulation.
- *Offset by higher operating revenues* of approximately $43 million due to increased generation, favorable pricing and the favorable impact from new capacity markets. This was partially offset by lower gains in the region s risk management activities and lower sales of emission allowances due to the 36% reduction in market prices.

Operating Revenues

Operating revenues increased by $43 million for the nine months ended September 30, 2007, compared to 2006, due to:

- *Energy revenues* increased by approximately $82 million, of which $42 million is due to increased generation, $35 million due to a 5% increase in average realized market prices and $5 million from new contracted energy revenues.
  - o *Generation* increased by 6%, primarily driven by increases at the region s Arthur Kill, Oswego and Indian River plants. The Arthur Kill plant increased generation by 342 thousand MWh due to transmission constraints around New York City, the Oswego plants generation increased by 95 thousand MWh due to a

colder winter during 2007 compared to 2006, and Indian River plants generation increased by 230 thousand MWh coming off weak pricing and generation in the third quarter 2006.

- o *Price* - on average, realized prices in the Northeast increased by 5% due to a combination of higher mix of higher priced NYC generation coupled with improved economic energy hedge trading resulting in a $35 million increase in energy revenues.

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Capacity revenues increased by $55 million, of which $30 million was from the region s NEPOOL assets, $22 million from the region s PJM assets and $3 million from the region s New York Rest of State assets.

- o *NEPOOL* The region s NEPOOL assets benefited from the new LFRM market and transition capacity market, both of which were introduced in the fourth quarter 2006. Capacity revenues increased by $25 million from the LFRM market and $16 million from transition capacity payments, partially offset by an $11 million reduction following the expiration of an RMR agreement for the region s Devon plant on December 31, 2006 and by RMR payments from the region s Norwalk plant which started in the third quarter 2007.
- o *PJM* On June 1, 2007, the new RPM capacity market became effective in PJM increasing capacity revenues by approximately $22 million.
- o *NYISO* New York Rest of State capacity prices increased by 101% 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.

These were partially offset by:

Risk management activities Risk management activities resulted in $23 million of gains during 2007 compared to an $88 million gain in 2006. The $23 million gain includes a $26 million unrealized loss related to the changes in the fair value of forward derivative positions compared to a $107 million gain in the same period in 2006. Risk management activities also include gains in the value of settled power positions of $49 million for the nine months ended September 30, 2007, compared to a $19 million loss for the same period in 2006. This $68 million increase was largely driven by favorable gas trading of $35 million, coupled with an increase in option premium revenues of $18 million and higher energy trading results of $25 million that were partially offset by unfavorable capacity trading of $9 million.

O*ther revenues* of approximately $29 million, of which approximately $51 million was due to reduced activity in the trading of emission allowances following both an increase in generation and a 36% decrease in market prices. This decrease was partially offset by $27 million in higher gas sales to third parties due to the sale of excess natural gas.

Cost of Energy

Cost of energy increased by $24 million for the nine months ended September 30, 2007, compared to 2006, due to:

Natural gas costs increased by approximately $34 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 and third quarters of 2007.

This was partially offset by:

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

Coal costs despite increased generation of 245 thousand MWh at the region s coal-fired plants, coal costs decreased by $4 million due to a 4% decrease in average contracted prices of purchased coal.

Other Operating Expenses

Other operating expenses increased by $26 million for the nine months ended September 30, 2007, compared to 2006, due to:

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.

Increased plant and regional spending by $6 million reflecting higher staffing costs, increased environmental remediation spending and higher corporate allocations by $3 million.

Development costs increased development spending by $4 million as part of *Repowering*NRG initiatives. Development costs totaled $6 million in the first nine months of 2007 primarily related to the Company s New York IGCC project.

These were partially offset by:

Favorable property tax of approximately $7 million due to a tax law change in 2006 that resulted in the reduction of a property tax receivable of $5 million in 2006 together with the current year effect of lower tax assessments on several of the region s power plants for fiscal 2007.

South Central Region

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

Selected income statement data

(In millions except otherwise noted)	Three months ended September 30, 2007	2006	Change %	Nine months ended September 30, 2007	2006	Change %
Operating Revenues						
Energy revenue	$ 126	$ 102	24	$ 314	$ 252	25
Capacity revenue	56	51	10	163	148	10
Risk management activities	11	12	(8)	19	16	19
Contract amortization	7	5	40	18	13	38
Other revenues		1	NA		8	NA
Total operating revenues	200	171	17	514	437	18
Operating Costs and Expenses						
Cost of energy	131	103	27	317	243	30
Other operating expenses	21	18	17	83	67	24
Depreciation and amortization	17	17		51	51	
Operating income	$ 31	$ 33	(6)	$ 63	$ 76	(17)
MWh sold (in thousands)	3,748	3,444	9	9,579	9,037	6
MWh generated (in thousands)	3,192	3,046	5	8,416	8,273	2
Business Metrics						
Average on-peak market power prices ($/MWh)	60.42	60.90	(1)	60.80	57.38	6
Cooling Degree Days, or CDDs[(a)]	1,249	1,131	10	1,853	1,732	7
CDD s 30 year rolling average	997	997		1,487	1,487	
Heating Degree Days, or HDDs[(a)]	10	44	(77)	2,080	1,871	11
HDD s 30 year rolling average	33	33		2,226	2,226	

(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 Revenues

Operating revenues increased by approximately $29 million for the three months ended September 30, 2007, compared to 2006, due to:

Energy revenues increased by $24 million, of which $22 million was due to a new baseload contract which became effective January 1, 2007. Energy revenues from the region s cooperative customers also increased by $4 million due to a 3% increase in MWh sold and a higher contractual fuel adjustment charge.

Capacity revenues increased by approximately $5 million, of which $2 million was attributable to higher rates as a result of the region s market setting a new summer peak in 2006, with an additional $2 million due to the contractual pass-through of higher transmission costs. The new baseload contract also contributed $2 million to capacity revenues.

Cost of Energy

Cost of energy increased by approximately $28 million for the three months ended September 30, 2007, compared to 2006, due to:

- *Purchased energy* increased by approximately $17 million as a result of the new baseload contract and a 3% increase in the region s cooperative customers load requirement.
- *Transmission costs* increased by approximately $4 million of which $2 million was related to contractual price increases for network services, coupled by a $2 million increase due to increased energy sales from the new baseload contract and increased merchant trading activity.
- *Coal costs* increased by approximately $4 million due to a 4% increase in coal generation at the region s Big Cajun II plant following higher energy demand.

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Other Operating Expenses

Other operating expenses increased by approximately $3 million for the three months ended September 30, 2007, compared to 2006. This was due to increased maintenance expenses at the region s Big Cajun II plant.

Year-to-date Results

Operating Income

Operating income for the region declined by $13 million for the nine months ended September 30, 2007, compared to 2006, due to higher operating expenses, despite a 1% increase in generation at the region s Big Cajun II plant.

Operating Revenues

Operating revenues increased by $77 million for the nine months ended September 30, 2007, compared to 2006, due to:

Energy revenues increased by approximately $62 million due to a new baseload contract which contributed $53 million in energy contract revenues, increasing contract sales volume by approximately 1 million MWh. Following a contractual fuel adjustment charge, energy revenues increased by $10 million from the region s cooperative customers.

Capacity revenues increased by approximately $15 million, of which $6 million was due to higher rates as a result of the region s setting a new summer peak in 2006 and higher contractual transmission pass-through costs of $5 million. Similar to 2006, in August 2007 the region set a new system peak of 2,123 MW which will impact capacity revenue over the next year. Due to improved market conditions in the region, merchant revenues also increased by $2 million from the Rockford plants.

Cost of Energy

Cost of energy increased by $74 million for the nine months ended September 30, 2007, compared to 2006, due to:

Purchased energy increased by approximately $46 million due to a 305,535 MWh increase in the region s cooperative load requirements. An increase of 198 hours in planned maintenance at the region s Big Cajun II facility also resulted in an increase in market purchases. In addition purchased energy also increased as a result of a seasonal spring outage coupled with a 2% increase in natural gas prices in 2007.

Coal costs increased by approximately $15 million, of which $8 million was due to a 6% increase in contracted coal prices and $3 million due to higher coal consumption. In addition, the region incurred higher coal transportation costs due to an increase in the contractual fuel surcharge.

Transmission costs increased by approximately $12 million of which $4 million was due to contractual increases related to network transmission service. Point-to-point transmission costs also increased by $8 million reflecting more off-system sales.

Other Operating Expenses

Other operating expenses increased by approximately $16 million for the nine months ended September 30, 2007, compared to 2006, due to:

Maintenance expense increased by approximately $7 million as the scope of work on planned outages were more extensive in 2007.

Franchise tax Louisiana state franchise tax increased by approximately $7 million because this tax is assessed based on the Company s total debt and equity, which increased significantly following the acquisition of Texas Genco LLC.

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West Region

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

Selected income statement data

(In millions except otherwise noted)	Three months ended September 30, 2007	Three months ended September 30, 2006	Change %	Nine months ended September 30, 2007	Nine months ended September 30, 2006[(b)]	Change
Operating Revenues						
Energy revenue	$ 1	$ 31	(97)	$ 2	$ 58	(97)
Capacity revenue	32	27	19	87	47	85
Risk management activities		(2)	NA		(3)	NA
Other revenues		3	NA	1	7	(86)
Total operating revenues	33	59	(44)	90	109	(17)
Operating Costs and Expenses						
Cost of energy	1	33	(97)	2	59	(97)
Other operating expenses	19	16	19	58	34	71
Depreciation and amortization	1		NA	2	1	100
Operating income	$ 12	$ 10	20	$ 28	$ 15	87
MWh sold (in thousands)	620	620		767	1,314	(42)
MWh generated (in thousands)	620	620		767	1,314	(42)
Business Metrics						
Average on-peak market power prices ($/MWh)	68.87	71.90	(4)	65.93	61.31	8
Cooling Degree Days, or CDDs[(a)]	634	640	(1)	770	880	(13)
CDD s 30 year rolling average	506	506		663	663	
Heating Degree Days, or HDDs[(a)]	91	53	72	1,917	1,931	(1)
HDD s 30 year rolling average	108	108		2,081	2,081	

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

Quarterly Results

Operating Income

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

Capacity revenues increased by approximately $5 million due to new tolling agreements at the region s Encina and Long Beach plants, which was partially offset by $1 million due to the sale of Red Bluff and Chowchilla plants.

- o *Encina* In January 2007, NRG commenced a new tolling agreement for the region s Encina plant which contributed $3 million in capacity revenues for the three months ended September 30, 2007.
- o *Long Beach* On August 1, 2007, NRG successfully completed the repowering of a 260 MW gas-fueled generating plant at its Long Beach generating facility, which contributed approximately $5 million in capacity revenues for the three months ended September 30, 2007.

Cost of energy decreased by $32 million as a result of the new tolling agreement at the region s Encina plant, which requires the tolling agreement counterparty to supply its own natural gas to run the plant.

Risk management activities through the end of 2006 the region entered into natural gas swaps/contract to economically hedge the impact of gas price fluctuations at the region s Saguaro plant. The region has not needed to enter into similar contracts in 2007 thus increasing operating income by approximately $2 million.

This increase was offset by:

Energy revenues decreased by approximately $30 million due to a new tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment during 2007 as opposed to the right to schedule and dispatch from the plant during 2006.

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- *Development costs* increased by $1 million, reflecting *Repowering*NRG initiatives at the region s El Segundo and Encina sites.
- *Other revenues* decreased by approximately $3 million due to the new tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment during 2007 as opposed to the right to schedule and dispatch ancillary services from the plant.

Year-to-date Results

Operating Income

Operating income increased by $13 million for the nine months ended September 30, 2007, compared to 2006. Excluding the consolidation of WCP s results following the acquisition of Dynegy s 50% interest on March 31, 2006, operating income increased by $6 million, due to:

- *Capacity revenues* increased by approximately $14 million, excluding the first quarter 2007, due to new tolling agreements at the region s Encina and Long Beach plants:
  - o *Encina* In January 2007, NRG signed a new tolling agreement for the region s Encina plant which contributed $8 million in capacity revenues for the nine months ended September 30, 2007.
  - o *Long Beach* On August 1, 2007, NRG successfully completed the repowering of a 260 MW gas-fueled generating plant at its Long Beach generating facility, which contributed approximately $5 million in capacity revenues for the three months ended September 30, 2007.
- *Cost of energy* decreased by $56 million, excluding the first quarter 2007, due to the new tolling agreement entered into at the Encina plant in 2007, which requires the counterparty to supply their own fuel.

This increase was offset by:

- *Energy revenues* decreased by approximately $55 million, excluding the first quarter 2007, primarily due to the tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment in return for the right to schedule and dispatch from the plant.
- *Development expenses* increased by $4 million, reflecting *Repowering*NRG initiatives at the region s El Segundo and Encina sites.
- *Other revenues* decreased by approximately $6 million due to the new tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment in return for the right to schedule and dispatch ancillary services from the plant.
- *G&A costs* increased by approximately $3 million due to increased labor costs to support the acquired WCP assets.
- *Asset sale* due to the sale of the Red Bluff and Chowchilla plants, operating income decreased by $1 million.

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Liquidity and Capital Resources

Liquidity Position

As of September 30, 2007 and December 31, 2006, NRG s liquidity was approximately $2.3 billion and $2.2 billion, respectively, comprised of the following:

(In millions) As of	September 30, 2007	December 31, 2006
Cash and cash equivalents	$1,171	$795
Restricted cash	62	44
Total Cash	1,233	839
Synthetic letter of credit availability	68	533
Revolver credit facility availability	997	855
Total liquidity	$2,298	$2,227

As discussed below in the First and Second Lien Structure discussion, on October 30, 2007, NRG successfully moved certain second lien holders to a pari passu basis with the Company s first lien holders effectively releasing approximately $557 million in letters of credit previously provided to them under the Company s Synthetic Letter of Credit Facility.

Management believes that these amounts and cash flows from operations will be adequate to finance operating and maintenance 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.

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 Facility 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 Company s results of operations for the nine months ended September 30, 2007, which was 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 cash dividends on common stock upon the implementation of the Holdco structure;
exclude payments made on the Holdco Credit Facility, once funded, from being considered restricted payments under the Senior Credit Facility;
modify the existing excess cash flow prepayment mechanism to provide that prepayments are offered to both NRG and Holdco on a pro rata basis and to provide for mandatory annual prepayments; 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.

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On August 6, 2007, NRG entered into an agreement with BNP Paribas, or BNP, whereby BNP has agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. BNP has agreed to issue up to $350 million of letters of credit under the revolver. This increases the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility to $650 million. In addition, NRG is permitted to issue additional letters of credit of up $350 million under the Senior Credit Facility through other financial institutions.

Prior to year end 2007, the Company intends to use cash on hand to prepay, without penalty, up to $300 million of its Term B loan under the Senior Credit Facility. With this anticipated prepayment, the Company expects to meet a financial ratio by the end of 2007 that would result in a 0.25% reduction in the interest rate on both its Term B loan and Synthetic Letter of Credit Facility. This is expected to result in approximately $10 million in pre-tax interest savings during 2008. Any prepayment made will be credited against the mandatory annual prepayment which is required in March 2008 under the Senior Credit Facility.

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 as of September 30, 2007. The formation of the Holdco structure and the drawdown on the Holdco Credit Facility are subject to certain conditions including approval by several regulatory bodies. The company expects to be able to satisfy these conditions during the fourth quarter 2007.

With the recent recovery in financial markets and the prices of NRG s Senior Notes, on November 2, 2007, the Company exercised its right to provide its Senior Note holders with a conditional change of control notice, and related offer to purchase the Company s Senior Notes at 101% of par, prior to the actual formation of the Holdco structure. Concurrent with this change of control offer, NRG is seeking consent from the same Senior Note holders to waive the change of control in exchange for a 0.125% fee. Under the terms of the Company s Senior Notes, holders will have thirty calendar days to respond to the change of control offer and consent solicitation.

Based on the outcome of this change of control offer and consent solicitation, NRG will make a determination of whether to move forward with the Holdco structure prior to the end of 2007. If the Holdco Credit Facility is drawn, the net proceeds will simultaneously be used to pay down a portion of the Company s Term B loan under its Senior Credit Facility. As a result, the Company s Senior Notes restricted payments capacity that governs, among other things, the amount of capital that can be returned to shareholders will expand by a similar amount. In addition, NRG will retain the right, but not the obligation, to purchase any or all of the Senior Notes tendered by investors during this process regardless of whether NRG decides to move forward and form the Holdco structure.

In connection with the transaction, Bank of America has provided the Company with a $4.2 billion senior unsecured debt financing commitment, subject to customary conditions, to fund the tender offers together with a portion of the Company s cash on hand.

Capital Allocation Program

NRG completed Phase II of its Capital Allocation Program in the third quarter 2007, with the repurchase of 1,337,500 shares of the Company s common stock for approximately $53 million. The Company has thus repurchased 7,006,700 shares of NRG common stock for approximately $268 million for the nine months ended September 30, 2007.

First and Second Lien Structure

NRG has granted first and 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 first or 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 first and 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 part of NRG s amended and restated credit agreement signed June 8, 2007, the Company obtained the ability to move its current second lien counterparty exposure to the first lien, on a pari passu basis with the Company s existing first lien lenders. In exchange for moving some second lien holders to a pari passu basis with the Company s first lien lenders, the counterparties will relinquish letters of credit issued by NRG which they held as a part of their collateral package.

As of September 30, 2007, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the first and second lien structure was approximately $23 million. On October 30, 2007, NRG successfully moved certain second lien holders to a pari passu basis with the Company s first lien lenders effectively releasing $557 million of letters of credit. With the movement to the first lien structure, the Company significantly reduces its outstanding letters of credit exposure and thereby increases its liquidity. As of October 30, 2007, the net discounted exposure on the agreements and hedges that were subject to the first and second lien structure was approximately $94 million. In addition, with the release of $557 million in letters of credit will result in a net discounted exposure of approximately $321 million.

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 first and second lien structure as of October 25, 2007:

Equivalent Net Sales secured by First and Second Lien Structure[(a)]	2007[(b)]	2008	2009	2010	2011	2012
In MW	3,733	3,958	3,781	3,026	3,236	570
As a percentage of total forecasted baseload capacity	54%	57%	54%	44%	47%	9%

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

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

Capital Expenditures

The following table summarizes NRG s capital expenditure forecast relating to maintenance and environmental projects, for the full year 2007 of approximately $311 million, inclusive of the $183 million spent during the first nine months of 2007:

(In millions)	Maintenance	Environmental	Total
Northeast	$ 26	$ 36	$ 62
Texas	96		96
South Central	11		11
West	2		2
Thermal, International and Other	12		12
Capital expenditures through September 30, 2007	$ 147	$ 36	$ 183
Capital expenditures through the remainder of 2007	84	44	128
Total capital expenditures for 2007	$ 231	$ 80	$ 311

Texas capital expenditures in the Texas region were approximately $96 million due to:

- o *STP* $47 million related to nuclear fuel and maintenance
- o *Fossil plants* $45 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.

Northeast capital expenditures in the Northeast region were approximately $62 million due to:

- o *Huntley and Dunkirk* approximately $36 million was related to baghouse emission project at these two facilities.
- o *Other Northeast facilities* general plant improvements.

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

Repowering*NRG *Project Deposits

NRG has made non-refundable deposits relating to *Repowering*NRG initiatives totaling approximately $30 million primarily towards the procurement of wind turbines. 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 $412 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 deposits it already has made.

NOL and Other Tax Discussions

As of September 30, 2007, the Company had generated total domestic pretax book income of $708 million which fully utilized the cumulative domestic NOL in the amount of $65 million. In addition, NRG has cumulative foreign NOL carryforwards of $290 million, of which $78 million will expire in 2016 and of which $212 million do not have an expiration date.

In addition to these amounts, the Company has $712 million of tax effected unrecognized tax benefits which relate primarily to net operating losses for tax return purposes but have been classified as capital loss carryforwards for financial statements purposes and for which a full valuation allowance has been established. As a result of the Company s tax position, and based on current forecasts,

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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, of the $712 million of tax effected unrecognized tax benefits, the Company has recorded a non-current liability of $51 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authorities.

On July 6, 2007, the German government passed the Tax Reform Act of 2008, which reduces the German statutory and resulting effective tax rates on earnings from approximately 36% to approximately 27% effective January 1, 2008. Due to this reduction in the statutory and resulting effective tax rate, during the third quarter 2007, NRG recognized a $30 million tax benefit and as of September 30, 2007, NRG had a German net deferred tax liability of approximately $79 million which includes the impact of this tax rate change.

Cash Flow Discussion

	Nine months ended September 30			
(In millions)		**2007**		**2006**
Net cash provided by operating activities	$	976	$	1,166
Net cash used in investing activities		(232)		(4,159)
Net cash provided/(used) by financing activities	$	(375)	$	3,872

Net Cash Provided By Operating Activities

For the nine months ended September 30, 2007, net cash provided by operating activities decreased by $190 million compared to the same period in 2006. This was due to:

Adjusted net income an increase in NRG s adjusted net income of $469 million for the nine months ended September 30, 2007 as compared to 2006. Adjustments to net income were primarily due to a $281 million reduction in contract amortization during 2007 compared to 2006 following the Hedge Reset transactions coupled with a $224 million increase in adjustments for derivative activity.

Collateral deposits following an upward shift of the forward price curves, NRG s net collateral deposits in support of derivative contracts increased by $107 million during the nine months ended September 30, 2007, compared to a decrease of $397 million during the same period of 2006, a difference of $504 million. As of September 30, 2007, NRG had a net cash collateral deposit of $53 million.

Working Capital activity for the period resulted in a decrease of $115 million in cash flows from working capital compared to an increase of $40 million for the same period in 2006, a difference of $155 million. This was due to:

o *Accounts Receivable* the change in accounts receivable reduced cash flows from working capital by $186 million, which consisted of:

Hedge Reset an increase in billable revenues of approximately $59 million due to the Hedge Reset transaction in November 2006 as third quarter 2007 prices on energy revenues increased by an average of $22 per MWh.

Absence of Capacity Auctions 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 by $45 million during the first nine months of 2007 as compared to 2006 following this reduction of the PUCT auctioned capacity.

Acquisitions $31 million due to the receipt of trade receivables related to sales prior to the purchase of Texas Genco LLC was excluded from working capital as they were included as part of the purchase price. The balance of the increase in accounts receivable was due to the increased trade receivable activity following the first quarter 2006 acquisition of Texas Genco LLC and WCP.

o *Pension Contribution* a decrease in other liabilities of $43 million was related to pension funding as the Company increased its pension contribution in 2007.

Net Cash Used in Investing Activities

For the nine months ended September 30, 2007, net cash used in investing activities was approximately $3.9 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 $150 million due to expenditures of approximately $126 million for *Repowering*NRG projects, primarily $75 million for the Long Beach plant and $15 million in deposits for wind

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turbines. In addition, the Company initiated a baghouse project at the Huntley and Dunkirk plants which also increased capital expenditures by approximately $46 million.

Asset Sales The sale of the Company s Red Bluff and Chowchilla plants and equipment increased proceeds from asset sales by approximately $57 million.

Discontinued Operations during 2006 NRG received proceeds of $239 million from the sale of Flinders, Audrain, and Resource Recovery.

Net Cash Provided/(Used) in Financing Activities

For the nine months ended September 30, 2007, net cash used by financing activities decreased by approximately $4.2 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 were $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 nine months ended September 30, 2007, NRG repurchased an additional 7,006,700 shares of the Company s common stock for approximately $268 million as part of the Capital Allocation Program.

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New and On-going Company Initiatives

FOR*NRG *Update

During the second quarter 2006, NRG announced the expansion and extension of the *FOR*NRG program due to the addition of the Company s Texas assets from $105 million to $200 million in improvements to its earnings before taxes, depreciation and amortization plus an additional $50 million of incremental cash benefit by 2009. The overall program goal was $250 million per year of recurring, cumulative pre-tax earnings improvement by 2009. FORNRG contributed $39 million to pre-tax earnings in 2005 and $144 million in 2006. For 2007, the Company now expects to achieve $220 million which exceeds the previously announced 2007 *FOR*NRG target of $200 million. These better than expected 2007 results are being driven by:

- Exceeding overall plant performance targets, including the recapture of plant generating capacity,
- Implementing a centralized procurement structure to leverage purchase price power throughout the Company, and
- Higher corporate headquarter contributions.

These results, combined with additional *FOR*NRG opportunities identified during the year have allowed NRG to accelerate the overall program targets of $250 million by a full year to 2008. The Company continues to review the program s potential to expand and extend the program into 2009 and beyond.

Repowering*NRG *Update

Most of the Company s *Repowering*NRG projects continue in the development phase. During the third quarter 2007, the Company commissioned its first repowering project at the Long Beach Generating station, and other projects made progress in permitting, site planning and other critical development activities. The following is a summary of *Repowering*NRG projects which met significant milestones or made significant progress in their development.

STP Repowering Update

On September 24, 2007, NRG and STPNOC filed a COLA, with the Nuclear Regulatory Commission to build and operate two new nuclear units at the South Texas Project nuclear power station site. The total rated capacity of the new units, STP 3 and 4, will equal or exceed 2,700 MW. With the COLA submitted, the Commission has begun an estimated two-month acceptance review process and the Company anticipates that its application will be accepted in the fourth quarter 2007.

Also, on October 29, 2007, NRG and the City of San Antonio, acting through the City Public Service Board of San Antonio, or CPS Energy, entered into an agreement whereby the parties agreed to be equal partners in the development of STP Units 3 and 4, and, in the event either party chooses at any time not to proceed, gives the other party the right to proceed with the project on its own. The agreement provides for CPS Energy, based on its ownership percentage, to reimburse NRG for a pro rata share of project costs NRG has incurred, and to pay a pro rata share of future development costs.

The Company and STPNOC signed a project services agreement with Toshiba Corporation, a diversified major Japanese manufacturer. Under this agreement, Toshiba will support NRG in the design, engineering, construction, and procurement of two nuclear reactors. STPNOC and NRG are engaged in continuing negotiations with Toshiba and its potential consortium members about a definitive engineering, procurement and construction agreement. In addition, NRG has reserved the major, long-lead components for the STP expansion projects, including the first reactor pressure vessel.

Cedar Bayou Generating Station

NRG Cedar Bayou Development Company LLC, or NRG Cedar Bayou (a subsidiary of NRG Energy, Inc.) and EnergyCo Cedar Bayou 4, LLC, or EnergyCo Cedar Bayou (a subsidiary of EnergyCo, LLC, which is a joint venture between PNM Resources Inc. and a subsidiary of Cascade Investment, LLC), entered into definitive agreements on August 1, 2007 pursuant to which the two parties will jointly develop, construct, operate and own, on a 50/50% undivided interest basis, 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.

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In exchange for a 50% undivided interest in certain tangible and intangible assets and rights to use facilities owned by NRG, EnergyCo Cedar Bayou agreed to pay NRG $45 million over a 24 month period. Going forward, the parties will share equally the obligations to fund plant construction and purchases of additional equipment. NRG will also provide various ongoing services related to construction management, plant operations and maintenance, and use of NRG facilities 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 and EnergyCo Cedar Bayou entered into an Engineering, Procurement and Construction Agreement with Zachry Construction Corp. to construct the plant that is expected to be completed within 24 months.

Long Beach

On August 1, 2007, the Company successfully completed and commissioned the repowering of 260 MW of new gas-fired 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 PPA executed with SCE in November 2006. Total incremental capital spending for the project was approximately $75 million.

Wind Power Projects

The Company, working through its Padoma Wind Power subsidiary, has reached a stage of advanced development with respect to three wind projects, totaling approximately 418 MW. The first 150 MW project which is contingent upon reaching a joint construction and ownership agreement with a third party is scheduled to commence construction during the fourth quarter 2007, the second 117.6 MW project is scheduled to commence construction in the spring of 2008, and the third 150 MW project is scheduled for construction during 2009. The total project cost for the three projects, net of third party contributions, is estimated to be approximately $682 million. Project level financing is expected to range from approximately 50% 70% of project costs, thereby requiring a net cash investment by the Company of approximately $273 million. The expected capital cost for 2007 is expected to be approximately $162 million of which $36 million is projected to be funded through non-recourse debt. In addition, the Company is working on several projects located in the California and Texas with construction planned for 2010 and beyond.

Development Costs

During the first nine months of 2007, NRG incurred approximately $108 million in costs associated with development efforts related to *Repowering*NRG initiatives, of which $75 million has been spent towards STP, mainly for engineering studies required in preparation for the submission of a combined construction operating license application towards the construction of Units 3 and 4.

Repowering*NRG *Capital Expenditures

The following table summarizes the Company s *Repowering*NRG capital expenditures for the full year 2007 as well as what has been spent through the first nine months of 2007 by region:

(In millions)		***RepoweringNRG***
Northeast	$	6
South Central		6
Texas		46
West		75
Wind and other projects		125
Total	$	258
*Repowering*NRG capital expenditures through September 30, 2007		126
Remaining *Repowering*NRG capital expenditures for 2007	$	132

econrg Update

Commercial Scale Carbon Capture and Sequestration Demonstration

NRG has signed a memorandum of understanding with Powerspan Corp., or Powerspan, to jointly design, construct, and operate a demonstration facility that will be among the largest carbon capture and sequestration projects in the world and may be the first to achieve commercial scale from an existing coal-fueled power plant. The project will be constructed at the Company s W.A. Parish plant near Sugar Land, Texas, and is designed to capture and sequester up to 90% of the carbon dioxide from flue gas equal in quantity

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to that from a 125 MW unit using Powerspan s proprietary ECO_{2}™ technology, a post-combustion, regenerative process which uses an ammonia-based solution to capture CO_2 from the flue gas and release it in a form that is ready for safe transportation and permanent geological storage. Funding for the project, which is expected to be operational in 2011, is estimated to be in the range of $150 million to $200 million which will be provided by NRG, Powerspan, other outside investors, along with expected grants from government and non-government entities.

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 SFAS 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 SFAS 133. As of September 30, 2007, based on the Company s stock price, the redemption value of this embedded derivative was approximately $113 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 SFAS 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 SFAS 133. As of September 30, 2007, based on the Company s stock price, the redemption value of this embedded derivative was approximately $72 million.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments As of September 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 $139 million as of September 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. On August 6, 2007, NRG entered into an agreement with BNP Paribas, or BNP, whereby BNP has agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. BNP has agreed to issue up to $350 million of letters of credit. This increases the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility to $650 million 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 $350 million under the Senior Credit facility through other financial institutions.

As of September 30, 2007, the Company had issued $1.2 billion in letters of credit under the Synthetic Letter of Credit Facility. In addition, as of September 30, 2007, the Company had issued $3 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 Form 10-K.

Also see Note 14, *Commitments*

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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 third 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

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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 and 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 prices, (2) one-day holding period, (3) a 95% confidence interval, (4) a rolling 24-month forward looking period, and (5) market implied prices, volatilities and historical price correlations.

As of September 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 $32 million.

The following table summarizes average, maximum and minimum VAR for NRG for the three months ended September 30, 2007 and 2006.

VAR	**2007**	**2006**
As of September 30,	$ 32	$ 49
Average	31	58
Maximum	37	67
Minimum	24	49

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 September 30, 2007 for the entire term of these instruments entered into for both asset management and trading was approximately $11 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 October 25, 2007 was $2.03 billion.

As of September 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 September 30, 2007, NRG would have owed the counterparties approximately $30 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.

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NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of September 30, 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 September 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 $506 million.

Foreign Currency Exchange Risk

NRG may be subject to foreign currency risk as a result of the Company entering into purchase commitments with foreign vendors for the purchase of major equipment associated with *Repowering*NRG initiatives, as well as foreign currency risk relating to the Company s overseas investments. To reduce the risks to such foreign currency exposure, the Company may enter into transactions to hedge its foreign currency exposure using currency options and forward contracts. As a result of the Company s limited foreign currency exposure to date, the effect of foreign currency fluctuations has not been material to the Company s results of operations, financial position and cash flows.

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 $38 million as of September 30, 2007. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of September 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 September 30, 2007, NRG held collateral support of approximately $295 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 September 30, 2007:

(In millions, except ratios) **Credit Exposure**	**Exposure Before Collateral**	**Collateral**	**Net Exposure**
Investment grade	$1,358	$393	$ 965
Non-investment grade	56	56	
Not rated	163	11	152

Total	$1,577	$460	$1,117
Investment grade	86%	85%	86%
Non-investment grade	4	12	
Not rated	10%	3%	14%

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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 $803 million as of September 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 as of September 30, 2007, based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts as of September 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	(236)
Changes in fair value	(259)
Fair value of contracts as of September 30, 2007	$ (141)

	Fair Value of Contracts as of September 30, 2007				
Sources of Fair Value Gains/(Losses) (In millions)	**Maturity Less than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in excess 4-5 Years**	**Total Fair Value**
Prices actively quoted	$ (13)	$ 7	$	$	$ (6)
Prices provided by other external sources	144	(71)	(201)	(31)	(159)
Prices provided by models and other valuation methods	6	18			24
Total	$137	$(46)	$(201)	$(31)	$(141)

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Item 4 Controls and Procedures

Under the supervision and with the participation of the Company s management, including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation of the effectiveness of the design and operation of Company s disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, the Company 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 report such that the information relating to NRG, including its consolidated subsidiaries, required to be disclosed in the Company s SEC reports (i) is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and (ii) is accumulated and communicated to the Company s management, including its principal executive officer, principal financial officer and principal accounting officer as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of NRG s management including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation of any changes in the Company s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the Company s most recently completed fiscal quarter. Based on that evaluation, the Company s principal executive officer, principal financial officer and principal accounting officer concluded that there has not been any change in the Company s internal control over financial reporting during the quarter that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PART II OTHER INFORMATION

Item 1 Legal Proceedings

For a discussion of material legal proceedings in which NRG was involved through September 30, 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 September 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
Second quarter 2007 Total	2,669,200	42.15	2,669,200	52,615,547
July 1 July 31				
August 1 August 31	1,337,500	39.36	1,337,500	
September 1 September 30				
Third quarter 2007 Total	1,337,500	39.36	1,337,500	
Year-to-date	7,006,700	$ 38.29	7,006,700	$

(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 completed 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

None

Item 5 Other Information

Annual Meeting NRG has changed the date of its 2008 Annual Meeting of Stockholders from May 15, 2008, as set forth in its Proxy Statement filed March 13, 2007, to May 14, 2008.

First and Second Lien Structure On October 30 , 2007, NRG successfully moved certain second lien holders to a pari passu basis with the Company s first lien lenders effectively releasing $557 million of letters of credit. As part of NRG s amended and restated credit agreement signed June 8, 2007, the Company obtained the ability to move its current second lien counterparty exposure to the first lien, on a pari passu basis with the Company s existing first lien lenders. In exchange for moving the second lien holders to a pari passu basis with the Company s first lien lenders, the counterparties will relinquish letters of credit issued by NRG which they held as a part of their collateral package. With the movement to the first lien structure, the Company significantly reduced its outstanding letters of credit exposure and thereby increased its liquidity. For a further discussion on the first and second lien structure see Note 14, *Commitments and Contingencies*, of this Form 10-Q.

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Rule 10b5-1 Trading Plans On September 5, 2007, the Company announced that David Crane, President and Chief Executive Officer and Robert Flexon, Executive Vice President and Chief Financial Officer, and other senior NRG executives, established trading plans in accordance with Rule 10b5-1 of the Securities Exchange Act.

Item 6 Exhibits

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)
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)
4.4	Thirteenth Supplemental Indenture, dated August 28, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (2)
4.5	Fourteenth Supplemental Indenture, dated August 28, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (2)
4.6	Fifteenth Supplemental Indenture, dated August 28, 2007, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (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 September 4, 2007.

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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
(Principal Executive Officer)

/s/ ROBERT C. FLEXON

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

/s/ CAROLYN J. BURKE

Carolyn J. Burke,
Controller
(Principal Accounting Officer)

Date: November 2, 2007

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