NRG ENERGY, INC.
Form 10-Q
May 09, 2006

Table of Contents

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

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

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

For the quarterly period ended: March 31, 2006 **Commission File Number: 001-15891**

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

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

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

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

Yes R No £

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

Large accelerated filer R Accelerated filer £ Non-accelerated filer £

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

Yes £ No R

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

Yes R No £

As of May 5, 2006, there were 136,976,099 shares of common stock outstanding.

TABLE OF CONTENTS
Index

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act. The words believes, projects, anticipates, plans, expects, intends, estimates and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statement. These factors, risks and uncertainties include the factors described under Risks Related to NRG Energy, Inc. in Item 1A of the Company s Annual Report on Form 10-K and the following:

General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel or other raw materials;

Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes in fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that we may not have adequate insurance to cover losses as a result of such hazards;

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

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

Our ability to operate our businesses efficiently, manage capital expenditures and costs tightly (including general and administrative expenses), and generate earnings and cash flow from our asset-based businesses in relation to our debt and other obligations;

Our potential inability to enter into contracts to sell power and procure fuel on terms and prices acceptable to us;

The liquidity and competitiveness of wholesale markets for energy commodities;

Government regulation, including compliance with regulatory requirements and changes in market rules, rates, and tariffs and environmental laws;

Price mitigation strategies and other market structures employed by independent system operators, or ISOs, or regional transmission organizations, that result in a failure to adequately compensate our generation units for all of their costs;

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

The success of the business following the acquisition of Texas Genco LLC and West Coast Power, LLC;

Lack of comparable financial data as the results of Texas Genco LLC are not reflected in prior period results; and

Operating and financial restrictions placed on us contained in the indentures governing our 7.25% and 7.375% unsecured senior notes due 2014 and 2016, respectively, our senior secured credit facility and in debt and other agreements of certain of our subsidiaries and project affiliates generally.

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

Table of Contents

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Acquisition	February 2, 2006 acquisition of NRG Texas
Acquisition Agreement	Acquisition Agreement dated September 30, 2005 underlying the February 2, 2006 acquisition of Texas Genco LLC, now referred to as NRG Texas
APB 18	Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock.*
BTA	Best Technology Available
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
Cal ISO	California Independent System Operator.
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CL&P	Connecticut Light & Power
CO (2)	Carbon dioxide
CPUC	California Public Utilities Commission,
CTDEP	Connecticut Department of Environmental Protection
CWA	Clean Water Act
DNREC	Delaware Department of Natural Resources and Environmental Control
EFORd	Equivalent demand forced outage rate
EITF 02-3	Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
FASB	Financial Accountings Standards Board
FERC	Federal Energy Regulatory Commission
FF-ACI	Fabric Filter with Activated Carbon Injection
FGD	Flue Gas Desulphurization
FIN 47	Financial Accounting Standards Board Interpretation No. 47
FIP	Federal Implementation Plan
Fresh Start	Reporting requirements as defined by SOP 90-7
GHG	Greenhouse Gases
IGCC	Integrated Gasification Combined Cycle
ISO	Independent System Operator, also referred to as regional transmission organizations, or RTO
ISO-NE	ISO New England, Inc.
LIBOR	London Inter-Bank Offered Rate
LNB/OFA	Low NOx Burner with Over Fire Air
MDE	Maryland Department of the Environment
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NAAQS	National Ambient Air Quality Standards
NiMo	Niagara Mohawk Power Corporation
NOx	Nitrogen oxides
NOL	Net operating loss

NQSO	Non-qualified stock option
NRC	United States Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYSDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
OTC	Ozone Transport Commission
PJM	PJM Interconnection, LLC
PJM Market	The wholesale and retail electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia
PM (2.5)	Fine particulate matter
PUCT	Public Utility Commission of Texas

Table of Contents

Powder River Basin, or PRB Coal	Coal produced in the northeastern Wyoming and southeastern Montana, which has low sulfur content
RCRA	Resource Conservation and Recovery Act
RECLAIM	Regional Clean Air Incentives Market
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability must-run
RTC	RECLAIM Trading Credit
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SDG&E	San Diego Gas & Electric
SEC	United States Securities and Exchange Commission
SERC	Southeastern Electric Reliability Council/ Entergy
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS 109	SFAS No. 109, *Accounting for Income Taxes*
SFAS 123R	SFAS No. 123 (revised 2004), *Share-Based Payment*
SFAS 133	SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*
SFAS 141	SFAS No. 141, *Business Combinations*
SFAS 142	SFAS No. 142, *Goodwill and Other Intangible Assets*
SFAS 144	SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SOP 90-7	Statement of Position 90-7 *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*
STP	South Texas Project NRG Texas s nuclear generating facility located in Bay City, TX of which we own a 44% interest
NRG Texas	Texas Genco LLC
US	United States of America
USEPA	US Environmental Protection Agency
US GAAP	Accounting principles generally accepted in the US
VCP	Voluntary Clean-up Program
WCP	WCP (Generation) Holdings, Inc.

Table of Contents

PART I FINANCIAL INFORMATION

Item 1 Condensed Consolidated Financial Statements and Notes

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

	Three Months Ended March 31, 2006	March 31, 2005
	(In millions, except per share amounts)	
Operating Revenues		
Revenues from majority-owned operations	$ 1,144	$ 597
Operating Costs and Expenses		
Cost of majority-owned operations	743	452
Depreciation and amortization	125	48
General, administrative and development	61	50
Corporate relocation charges		3
Total operating costs and expenses	929	553
Operating Income	215	44
Other Income/(Expense)		
Equity in earnings of unconsolidated affiliates	21	37
Write downs and losses on sales of equity method investments	(3)	
Other income, net	81	26
Refinancing expenses	(178)	(25)
Interest expense	(118)	(55)
Total other expense	(197)	(17)
Income From Continuing Operations Before Income Taxes	18	27
Income Tax Expense		5
Income From Continuing Operations	18	22
Gain From Discontinued Operations, net of Income Taxes	8	1
Net Income	26	23
Dividends for Preferred Shares	10	4
Income Available for Common Stockholders	$ 16	$ 19
Weighted Average Number of Common Shares Outstanding Basic	117	87
Income From Continuing Operations per Weighted Average Common Share Basic	$ 0.06	$ 0.20
Gain From Discontinued Operations per Weighted Average Common Share Basic	0.07	0.01
Net Income per Weighted Average Common Share Basic	$ 0.13	$ 0.21

Weighted Average Number of Common Shares Outstanding Diluted		119		88
Income From Continuing Operations per Weighted Average Common Share Diluted	$	0.06	$	0.20
Gain From Discontinued Operations per Weighted Average Common Share Diluted		0.07		0.01
Net Income per Weighted Average Common Share Diluted	$	0.13	$	0.21

See notes to condensed consolidated financial statements.

6

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

		March 31, 2006 (unaudited)		December 31, 2005
	(In millions, except shares and par value)			
ASSETS				
Current Assets				
Cash and cash equivalents	$	818	$	506
Restricted cash		67		64
Accounts receivable, less allowance for doubtful accounts of $2 and $2		426		284
Inventory		412		260
Derivative instruments valuation		267		404
Collateral on deposit in support of energy risk management activities		251		438
Deferred income taxes		3		4
Prepayments and other current assets		202		193
Current assets held for sale		11		43
Current assets discontinued operations				1
Total current assets		2,457		2,197
Property, plant and equipment, net of accumulated depreciation of $520 and $392		11,452		3,039
Other Assets				
Equity investments in affiliates		316		603
Notes receivable, less current portion		462		458
Goodwill Preliminary		2,748		
Intangible assets, net of accumulated amortization of $110 and $79		1,420		257
Nuclear decommissioning trust		320		
Derivative instruments valuation		58		22
Deferred income taxes		27		26
Other non-current assets		247		475
Non-current assets discontinued operations				354
Total other assets		5,598		2,195
Total Assets	$	19,507	$	7,431
LIABILITIES AND STOCKHOLDERS EQUITY				
Current Liabilities				
Current portion of long-term debt and capital leases	$	136	$	101
Accounts payable		346		268
Derivative instruments valuation		497		692
Deferred income taxes				
Accrued expenses and other current liabilities		381		180

Current liabilities discontinued operations				115
Total current liabilities		1,360		1,356
Other Liabilities				
Long-term debt and capital leases		7,822		2,581
Nuclear decommissioning reserve		295		
Nuclear decommissioning trust liability		299		
Deferred income taxes		800		135
Derivative instruments valuation		376		137
Out-of-market contracts		2,331		298
Other non-current liabilities		407		206
Non-current liabilities discontinued operations				240
Total non-current liabilities		12,330		3,597
Total Liabilities		13,690		4,953
Minority interest		1		1
3.625% Convertible Perpetual Preferred Stock (at liquidation value, net of issuance costs)		246		246
Commitments and Contingencies				
Stockholders Equity				
Preferred stock (at liquidation value, net of issuance costs)		892		406
Common Stock; $.01 par value; 500,000,000 shares authorized; 136,975,275 and 80,701,888 outstanding		1		1
Additional paid-in capital		4,448		2,431
Retained earnings		184		261
Less treasury stock, at cost 0 and 19,346,788 shares				(663)
Accumulated other comprehensive income/(loss)		45		(205)
Total stockholders equity		5,570		2,231
Total Liabilities and Stockholders Equity	$	19,507	$	7,431

See notes to condensed consolidated financial statements.

7

Table of Contents

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

	Three Months Ended March 31, 2006	March 31, 2005
	(In millions)	
Cash Flows from Operating Activities		
Net income	$ 26	$ 23
Adjustments to reconcile net income to net cash provided by operating activities		
Distributions more than equity earnings of unconsolidated affiliates	(12)	(32)
Depreciation and amortization	125	48
Amortization of financing costs and debt discount	10	2
Write-off of deferred financing costs and debt premium	47	(8)
Write down and loss on sale of equity method investments	3	
Deferred income taxes	46	(6)
Unrealized (gains)/losses on derivatives	(50)	85
Amortization of power contracts and emission credits	9	11
Nuclear decommissioning trust liability	(3)	
Amortization of unearned equity compensation	3	2
Gain on sale of discontinued operations	(10)	
Gain on Bourbonnais legal settlement	(67)	
Collateral deposit payments in support of energy risk management activities	230	(136)
Cash provided by changes in other working capital, net of acquisition and disposition affects	9	75
Net Cash Provided by Operating Activities	366	64
Cash Flows from Investing Activities		
Acquisition of Texas Genco LLC, net of cash acquired	(4,263)	
Acquisition of WCP, net of cash acquired	(25)	
Proceeds from sale of discontinued operations	15	
Proceeds from sale of investments	45	
Proceeds from sales of nuclear decommissioning trust fund securities	45	
Investments in nuclear decommissioning trust fund securities	(42)	
Decrease/(Increase) in restricted cash	(3)	34
Decrease in notes receivable	8	68
Capital expenditures	(35)	(11)
Return of capital from projects		1
Net Cash Provided by/(Used in) Investing Activities	(4,255)	92
Cash Flows from Financing Activities		
Payment of dividends to preferred stockholders	(10)	(4)
Funded letter of credit	350	
Issuance of common stock, net of issuance costs	986	
Issuance of preferred shares, net of issuance costs	486	

Deferred debt issuance costs	(164)	(1)
Proceeds from issuance of long-term debt	7,175	203
Principal payments on short and long-term debt	(4,623)	(699)
Net Cash Provided by/(Used in) Financing Activities	4,200	(501)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	1	(2)
Change in Cash from Discontinued Operations		(2)
Net Increase/(Decrease) in Cash and Cash Equivalents	312	(349)
Cash and Cash Equivalents at Beginning of Period	506	1,104
Cash and Cash Equivalents at End of Period	$ 818	$ 755

See notes to condensed consolidated financial statements.

Table of Contents

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

Note 1 General

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

Note 2 Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission s regulations for interim financial information and with the instructions to Form 10-Q. Accordingly, they do not include all of the information and notes required by generally accepted accounting principles for complete financial statements. The accounting policies we follow are set forth in Note 2 to the Company s financial statements in our Annual Report on Form 10-K for the year ended December 31, 2005. The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim consolidated financial statements contain all material adjustments (consisting of normal, recurring accruals) necessary to present fairly our consolidated financial position as of March 31, 2006, and the results of our operations and our cash flows for the three months ended March 31, 2006 and 2005. Certain prior-year amounts have been reclassified for comparative purposes.

Accounting Estimates

Management of the Company is required to make certain estimates and assumptions during the preparation of the consolidated financial statements in accordance with generally accepted accounting principles. These estimates and assumptions impact the reported amount of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the consolidated financial statements. They also impact the reported amount of net earnings during any period. Actual results could differ from those estimates.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of FAS 142, *Goodwill and Other Intangible Assets,* and consequently we do not amortize goodwill. FAS 142 requires us to evaluate goodwill and other intangibles for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using estimated future cash flows or other methods to assess fair value. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. FAS 142 also requires the amortization of intangible assets with finite lives.

New Accounting Pronouncements

We adopted SFAS 123(R) and Staff Accounting Bulletin 107, or SAB 107, on January 1, 2006 under a modified version of prospective application, or the modified prospective application. Under modified prospective application, we apply the provisions of SFAS 123(R) to new awards of stock based compensation and to awards modified, repurchased, or cancelled after the required effective date. SFAS 123(R) requires that we apply a forfeiture rate to existing awards and to calculate the retroactive impact of such application. If material, we must recognize in income the cumulative effect of this as a change in accounting principle as of the required effective date. Upon adoption of SFAS 123(R) on January 1, 2006, we applied a forfeiture rate to our existing awards and recognized in income approximately $1.1 million (net of tax of $0.8 million) as a reduction to compensation expense for the quarter ended March 31, 2006. This amount did not materially affect our consolidated financial position, results of operations or statement of cash flows for the quarter ending March 31, 2006.

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

Table of Contents

On January 1, 2006, we adopted EITF Issue No. 05-5, *Accounting for Early Retirement or Post-employment Programs with Specific Features (Such As Terms Specified in Altersteilzeit Early Retirement Arrangements)* , or EITF 05-5. EITF 05-5 provides guidance on the accounting for early retirement or post-employment programs with specific features, and specifically the terms of Altersteilzeit early retirement arrangements. The Altersteilzeit (ATZ) arrangement is a voluntary early retirement program in Germany designed to create an incentive for employees, within a certain age group, to transition from employment into retirement before their legal retirement age. If certain criteria are met by the employer, the German government provides to the employer a subsidy for bonuses paid to the employee and the additional contributions paid by the employer into the German government pension scheme under an ATZ arrangement for a maximum of six years. The Task Force reached a consensus that the employer should recognize the government subsidy when it meets the necessary criteria and is entitled to the subsidy. The Task Force also reached a consensus that payments made by the employer relative to the bonus feature and the additional contributions into the German government pension scheme (collectively, the additional compensation) should be accounted for as a post-employment benefit under SFAS 112, *Employers Accounting for Post-employment Benefits*, which prescribes that an entity should recognize the additional compensation over the period from the point at which the employee signs the ATZ contract until the end of the active service period. Upon adoption of EITF 05-5 on January 1, 2006, we recognized additional equity in earnings of unconsolidated affiliates of approximately $2.1 million, after tax, from our MIBRAG affiliate. This amount reflects the cumulative effect of the adoption of EITF 05-5, and did not materially affect our consolidated financial position, results of operations or statement of cash flows for the quarter ending March 31, 2006.

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

Note 3 Comprehensive Income/(Loss)

The components of total comprehensive income/(loss) are:

	Three Months Ended March 31	
	2006	**2005**
	(In millions)	
Net Income	$ 26	$ 23
Unrealized gain/(loss) from derivative activity	247	(82)
Foreign currency translation adjustment	3	(23)
Other comprehensive income/(loss), net of tax	250	(105)
Comprehensive income/(loss)	$ 276	$ (82)

Accumulated other comprehensive income/(loss) as of March 31, 2006 is as follows:

	As of March 31, 2006

		(In millions)
Accumulated other comprehensive loss as of December 31, 2005	$	(205)
Unrealized gain from derivative activity		247
Foreign currency translation adjustments		3
Accumulated other comprehensive income as of March 31, 2006		45

Note 4 Business Combinations

Acquisition of Texas Genco LLC

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

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

NRG Texas is the second-largest generation company in the ERCOT market and the largest owner of power plants in Houston. NRG Texas currently operates 48 operating generation units at nine power generation plants, including an undivided 44% interest in two nuclear generation units at STP. The aggregate net generation capacity of NRG Texas is 10,658 MW, which includes 5,178 MW of low marginal cost solid fuel and nuclear powered baseload plants. Similar to the rest of NRG, NRG Texas is a wholesale generator whose principal business is selling electric wholesale power produced by power plants to wholesale purchasers such as retail electric providers, power trading organizations and other power generation companies. To ensure steady cash flows from operations, NRG Texas has sold forward a substantial percentage of its baseload capacity under fixed price power contracts. These forward power sales agreements result primarily from bilateral negotiations.

The acquisition of Texas Genco LLC is accounted for using the purchase method of accounting and, accordingly, the purchase price is allocated to the assets acquired and liabilities assumed based on the estimated fair value of such assets and liabilities as of February 2, 2006. As it is difficult to estimate an allocation of purchase price without completed asset appraisals, we have made a preliminary allocation. The excess of the purchase price over the fair value of the net tangible and identified intangible assets acquired is goodwill. The allocation of the purchase price may be adjusted if additional information on known contingencies existing at the date of acquisition becomes available within one year after the acquisition, and longer for certain income tax items. Changes in allocation between preliminary assessed goodwill and plant or other intangibles would result in additional non-cash amortization expense.

The preliminary purchase price allocation is still subject to change due to additional acquisition costs. Certain asset sales, including the sale of the Webster Electric Generating Station that closed on April 7, 2006, were included as part of the working capital adjustments which were finalized on May 5, 2006.

The following table summarizes the preliminary fair value of the assets acquired and liabilities assumed at the date of acquisition. For purposes of acquisition costs, we have estimated the acquisition costs at approximately $128 million, increasing the total purchase price to approximately $6.2 billion.

	February 2, 2006 (In millions)
Current and non-current assets	$ 1,101
Coal inventory	33
In market power contracts	60
Water contracts	72
Coal contracts	110

Nuclear fuel contracts	110
SO_2 emission allowances	530
NO_x emission allowances	320
Property, plant and equipment	8,154
Deferred tax asset	1,503

Table of Contents

		February 2, 2006 (In millions)
Goodwill Preliminary		2,748
Total assets acquired		14,741
Current and non-current liabilities		923
Pension and post-retirement liability		213
Out of market coal contracts		140
Out of market gas swap contracts		472
Out of market power contracts		1,900
Deferred tax liability		2,127
Long term debt		2,735
Total liabilities assumed		8,510
Net assets acquired	$	6,231

The value of goodwill is preliminary and is still subject to change as we are still in the process of valuing all assets and liabilities acquired. We are also in the process of valuing the tax basis of the assets and liabilities acquired which will affect the deferred tax balances. Any changes to the fair value assessments and tax basis values will affect the final balance of goodwill.

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

Earlier estimates reported were based on estimated working capital;

Changes in the forecasted projected prices of electricity, coal and emission allowances. These projections greatly affect the expected future cash flows from NRG Texas, as well as the value of intangibles and out of market contracts;

The tax basis of the assets and liabilities acquired is more accurate, but still subject to revision; and

More precise information in respect to identifiable intangibles.

Currently, we have valued goodwill on a preliminary basis at approximately $2.7 billion. Our preliminary appraisal of Property, Plant and Equipment increased its fair value, as compared to Texas Genco LLC s historical cost, by approximately $4.6 billion. If the remaining goodwill balance is indicative of a further increase in value of depreciable property plant and equipment, depreciation expense for the period ended March 31, 2006 would increase by approximately $25 million, reducing income from continuing operations before tax to a loss of approximately $7 million.

Acquisition of Remaining 50% interest in WCP

On December 27, 2005, NRG entered into purchase and sale agreements for projects co-owned with Dynegy, Inc and these agreements were consummated on March 31, 2006. NRG acquired Dynegy s 50% ownership interest in WCP (Generation) Holdings, Inc., or WCP, and became the sole owner of WCP s 1,808 MW of generation in Southern California. In addition, NRG sold to Dynegy its 50% ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. In 2005, we wrote down the balance of our investment in Rocky Road by approximately $20 million to reflect our sale price of $45 million. NRG paid Dynegy a net purchase price of $160 million at closing.

Prior to the purchase, NRG had an existing investment in WCP accounted for as an unconsolidated equity method investment. The book value of NRG s investment prior to the purchase was approximately $159 million. The acquisition of the remaining 50% interest in WCP is accounted for as a step acquisition as our original equity investment was initiated in a prior period. The purchase price of each acquisition is determined separately per the consideration given at the date of each transaction, and therefore the purchase price allocation is determined separately based on the fair value for the percentage of net assets acquired at the date of each transaction.

Our Consolidated Balance Sheet as of March 31, 2006 assumes that the consideration paid below the historical book value of net assets acquired is related to the reduction in fair value of WCP s fixed assets. Once the WCP asset appraisals are final, the purchase price allocation may change significantly from the amounts included herein based on the results of appraisals, changes in market prices and analyses of the income tax effects of the acquisition.

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

	(in millions)
Current assets	$ 292
Property, plant and equipment	79
Intangible assets	22
Current liabilities	(26)
Non-current liabilities	(3)
Total Equity	$ 364

Table of Contents

Supplemental Pro Forma Information

The following supplemental pro forma information represents the results of operations as if NRG, NRG Texas and WCP had combined at the beginning of the respective reporting periods.

	Three Months Ended March 31	
	2006	2005
	(in millions)	
Operating revenues	$ 1,407	$ 1,266
Net income/(loss)	$ (297)	$ 63
Earnings per share Basic	$ (2.37)	$ 0.48
Earnings per share Diluted	$ (2.37)	$ 0.48
Weighted average number of shares outstanding Basic	130	122
Weighted average number of shares outstanding Diluted	130	123

The pro forma net loss for the three months ended March 31, 2006 reflect the following nonrecurring expenses incurred by Texas Genco LLC before February 2, 2006:

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

Note 5 Discontinued Operations

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

Statement of Financial Accounting Standards No. 144, or SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, our management considered cash flow analyses and offers related to the assets and businesses. This amount is included in income from discontinued operations, net of income taxes in the accompanying consolidated statements of operations. In accordance with SFAS No. 144, assets held for sale will not be depreciated commencing with their classification as such.

The assets and liabilities reported in the balance sheet as of December 31, 2005 as discontinued operations represent those of Audrain. The sale of Audrain to AmerenUE was finalized on March 29, 2006 for total cash proceeds of approximately $115 million and a net gain on sale of approximately $10 million.

For the three months ended March 31, 2006, discontinued operations consisted of various expenses related to Audrain. For the three months ended March 31, 2005, discontinued operations consisted of various expenses related to Northbrook New York, Northbrook Energy, Audrain and NRG McClain. All of these companies are included in our Wholesale Power Generation Other North America Segment.

Summarized results of operations of discontinued operations were as follows:

	Three Months Ended March 31, 2006	March 31, 2005
	(In millions)	
Operating revenues	$ (1)	$ 4
Pretax gain/(loss) from operations of discontinued components	(2)	1
Gain from sale of discontinued operations, net of income taxes	10	

Note 6 Investments Accounted for by the Equity Method

We have a 50% interest in MIBRAG and WCP, which were considered significant, as defined by applicable SEC regulations. As described in Note 4 above, we acquired the remaining 50% interest in WCP on March 31, 2006.

MIBRAG Summarized Financial Information

For the three months ended March 31, 2006 and 2005, we recorded equity earnings for MIBRAG of $12 million and $7 million, respectively. The following table summarizes the results of operations for MIBRAG, including interests owned by the Company and other parties for the periods shown below:

Results of Operations

	Three Months Ended March 31	
	2006	2005
	(In millions)	
Operating revenues	$109	$112
Operating income	30	22
Net income	24	16

As described in Note 2, we adopted EITF 04-6 as of January 1, 2006, which has negatively affected our equity investment in MIBRAG. As of December 31, 2005, MIBRAG had an asset totaling 157 million, approximately $185 million, representing the stripping costs incurred during mining operations, net of depreciation. Per the guidance of EITF 04-6, upon its adoption, the value of such stripping cost is to be eliminated with an offsetting charge to retained earnings. As such, our investment in MIBRAG has been reduced by 50% of the above mentioned asset, or approximately $93 million after tax, with an offsetting charge to retained earnings.

WCP Summarized Financial Information

For the three months ended March 31, 2006, we recorded equity earnings of $1 million for WCP after adjustments for the reversal of $2 million of project level depreciation expense. For the three months ended March 31, 2005, we recorded equity earnings of $4 million for WCP after adjustments for the reversal of $3 million of project level depreciation expense. The following table summarizes financial information for WCP, including interests owned by us and other parties for the periods shown below:

Summarized Results of Operations

	Three Months Ended March 31	
	2006	2005
	(In millions)	
Operating revenues	$67	$86
Operating income	(4)	
Net income (pretax)	(2)	2

NRG Cadillac

On January 1, 2006, NRG sold a 49.5% interest in a 38 MW biomass fuels generation facility located in Cadillac, Michigan, along with its right to receive Production Tax Credits, or PTCs, through 2009 to Lakes Renewable LLC. In consideration, NRG received an up-front payment of $0.3 million, approximately $4 million in a note receivable and a promissory note equal to the value of its share in future PTCs earned through 2009. The sale was contingent on the receipt of a favorable private letter ruling from the IRS and accordingly, all consideration was to be held in escrow. On April 13, 2006, NRG sold its remaining 0.5% share in Cadillac along with its interest in the notes receivable and promissory note to Delta Power for approximately $11 million. We will record a gain on the sale of approximately $10 million in the second quarter of 2006.

James River

NRG expects to sign a purchase and sale agreement to sell its 50% interest in James River in the second quarter 2006. As a result of this transaction, NRG wrote down the value of its equity investment by approximately $3 million in March 2006. We expect to close on the sale in the second quarter 2006.

Note 7 Accounting for Derivative Instruments and Hedging Activities

FAS 133 *Accounting for Derivative Instruments and Hedging Activities* , or FAS 133, as amended, requires us to recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. If certain conditions are met, we may be able to designate our derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives in Accumulated Other Comprehensive Income, or OCI and subsequently recognize in earnings when the hedged items impact income. The ineffective portion of a cash flow hedge is immediately recognized in income.

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

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

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

FAS 133 applies to our energy related commodity contracts, interest rate swaps and foreign exchange contracts.

Accumulated Other Comprehensive Income (OCI)

The following table summarizes the effects of FAS 133 on our OCI balance attributable to hedged derivatives for the three months ended March 31, 2006 before income taxes:

	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2005	$ (204)	$ 8	$ (196)
Unwound from OCI during the period:			
Due to unwinding of previously deferred amounts	(9)	(2)	(11)
Mark to market of hedge contracts (net of tax)	216	42	258
Accumulated OCI balance at March 31, 2006	$ 3	$ 48	$ 51
Gains/(Losses) expect to unwind from OCI during the next 12 months	(37)	2	(35)

The following table summarizes the effects of FAS 133 on our OCI balance attributable to hedged derivatives for the three months ended March 31, 2005:

	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2004	$ 5	$ 2	$ 7
Unwound from OCI during the period:			

Due to unwinding of previously deferred amounts	(3)	1	(2)
Mark to market of hedge contracts (net of tax)	(90)	10	(80)
Accumulated OCI balance at March 31, 2005	$ (88)	$ 13	$ (75)
Gains/(Losses) expected to unwind from OCI during the next twelve months	(76)	6	(70)

Gains of $11 million and gains of $2 million were reclassified from OCI to current period earnings during the three months ended March 31, 2006 and 2005, respectively, due to the unwinding of previously deferred amounts. These amounts are recorded on the

15

same line in the statement of operations in which the of hedged items are recorded. Also during the three months ended March 31, 2006 and 2005, we recorded gains in OCI of $258 million and losses of $80 million, respectively, related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to FAS 133 as of March 31, 2006 was an unrecognized gain of approximately $51 million. We expect $35 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Statement of Operations

The following table summarizes the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the three months ended March 31, 2006:

	Energy Commodities	Interest Rate (In millions)	Total
Revenue from majority-owned subsidiaries	$ 49	$	$ 49
Equity in net earnings of unconsolidated affiliates			
Interest expense		(3)	(3)
Total statement of operations impact before tax	$ 49	$ (3)	$ 46

The following table summarizes the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the three months ended March 31, 2005:

	Energy Commodities	Interest Rate (In millions)	Total
Revenue from majority-owned subsidiaries	$ (87)	$	$ (87)
Equity in net earnings of unconsolidated affiliates	12		12
Cost of operations	4		4
Total statement of operations impact before tax	$ (71)	$	$ (71)

Energy Related Commodities

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

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

The objectives for entering into such hedges include:

- Fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations;
- Fixing the price of a portion of anticipated fuel purchases for the operation of our power plants; and

Fixing the price of a portion of anticipated energy purchases to supply our load-serving customers.

During the three months ended March 31, 2006, we recognized losses of $8 million associated with the ineffectiveness on commodity cash flow hedges in support of our power generation activities. During the three months ended March 31, 2005, ineffectiveness on our commodity cash flow hedge relationships was immaterial to our financial results.

During the three months ended March 31, 2006 and 2005, our pre-tax earnings were affected by an unrealized gain of $49 million and an unrealized loss of $83 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with FAS 133. These amounts exclude the effect of unrealized gains and losses recorded by equity investees.

During the three months ended March 31, 2006 and 2005, we reclassified gains of $9 million and gains of $3 million, respectively, from OCI to current period earnings. Also during the three months ended March 31, 2006 and 2005, we recorded gains in OCI of $216 million and losses of $90 million, respectively, related to changes in the fair value of derivatives accounted for as hedges. We expect to reclassify approximately $37 million of deferred losses to earnings during the next twelve months on energy related derivative instruments accounted for as hedges. At March 31, 2006, we had hedge and non-hedge energy related commodities financial instruments extending through December 2026.

Interest Rates

We are exposed to changes in interest rates through our issuance of variable rate and fixed rate debt. In order to manage this interest rate risk, we have entered into interest-rate swap agreements. In January 2006, in anticipation of the New Senior Credit Facility, we entered into a series of forward starting interest rate swaps intended to hedge the variability in cash flows associated with this debt issuance. These transactions were designated as cash flow hedges and any gains/(losses) will be deferred on the balance sheet in Other Comprehensive Income. In February 2006, with the completion of the sale of the Senior Notes, we designated our fixed-to-floating interest rate swap as a hedge of fair value changes in the Senior Notes. This interest rate swap was previously designated as a hedge of our Second Priority Notes which were effectively replaced by the Senior Notes. In the first quarter, we recognized approximately $3 million in ineffectiveness associated with this hedging relationship.

At March 31, 2006, all of our interest rate swap arrangements have been designated as either cash flow or fair value hedges.

During the three months ended March 31, 2006 and 2005, our pre-tax earnings were not impacted by changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. During the three months ended March 31, 2006 and 2005, we reclassified gains of $2 million and losses of $1 million, respectively, from OCI to current period earnings and expect to reclassify approximately $2 million of deferred gains to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

At March 31, 2005, we had various interest-rate swap agreements extending through June 2019.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. As of March 31, 2006, the results of any outstanding foreign currency exchange contracts were immaterial to our financial results.

Note 8 Long-term Debt and Capital Leases

Cash Tender Offer and Consent Solicitation

On December 15, 2005, we commenced a cash tender offer and consent solicitation for any and all outstanding $1.1 billion aggregate principal amount of our 8% Second Priority Notes, or the NRG Notes. On such date, we also commenced a cash tender offer and consent solicitation for any and all outstanding $1.1 billion aggregate principal amount of Texas Genco and Texas Genco Financing Corp. s 6.875% senior notes due 2014, or the Texas Genco Notes. The offer to purchase the NRG Notes and the Texas Genco Notes was part of our previously announced financing plan in connection with our acquisition of Texas Genco LLC. As of February 2, 2006, NRG had received valid tenders from holders in aggregate principal amount of the NRG Notes, representing approximately 99.96% of the outstanding NRG Notes, and had received valid tenders from holders of the $1.1 billion in aggregate principal amount of the Texas Genco Notes, representing 100% of the outstanding Texas Genco Notes. The purchase price for the Second Priority Notes totaling approximately $1.2 billion was paid by NRG on February 2, 2006 and included $0.1 billion prepayment penalty which was recorded within debt refinancing expense on the consolidated income statement. The purchase price for the Texas Genco Notes totaling approximately $1.2 billion was paid by NRG on February 3, 2006 and include $0.1 billion prepayment penalty which was recorded as an acquisition cost for the acquisition of NRG Texas (see Note 4).

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

New Financings

New Senior Credit Facility

On February 2, 2006, we also entered into a new senior secured credit facility with a syndicate of financial institutions, including Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley & Co., Inc., as collateral agent, and Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc. as joint lead book-runners, joint lead arrangers and co-documentation agents providing for up to an aggregate amount of $5.575 billion, or the New Senior Credit Facility. The New Senior Credit Facility consists of a $3.575 billion senior first priority secured term loan facility, or the Term Loan Facility, a $1.0 billion senior first priority secured revolving credit facility, or the Revolving Credit Facility, and a $1.0 billion senior first priority secured synthetic letter of credit facility, or the Letter of Credit Facility. The New Senior Credit Facility replaced our then existing senior secured credit facility. The Term Loan Facility will mature on February 1, 2013 and will amortize in 27 consecutive equal quarterly installments of 0.25% of the original principal amount of the Term Loan Facility, beginning June 30, 2006, with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011. The Letter of Credit Facility will mature on February 1, 2013 and no amortization will be required in respect thereof. As of March 31, 2006, we had $3.575 billion outstanding under our Term Loan Facility. As of March 31, 2006, we had issued $798 million under our Letter of Credit Facility and $154 million in letters of credit under our Revolving Credit Facility.

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

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

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

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments, loans and advances;
- engage in mergers, acquisitions, consolidations and asset sales;
- pay dividends and other restricted payments;
- enter into transactions with affiliates;
- engage in business activities and hedging transactions;
- make capital expenditures;
- make debt payments; and
- make certain changes to the terms of material indebtedness.

In anticipation of the New Senior Credit Facility, in January 2006, we entered into a series of 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, we pay our counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we receive quarterly the equivalent of a floating interest payment based on 3-month LIBOR calculated on the same notional value. All payments by us and our counterparties are made quarterly, and LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps is $2.15 billion. The notional amounts and maturities of each tranche of these swaps are as follows:

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

Senior Notes

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

Interest is payable on the Senior Notes on February 1 and August 1 of each year beginning on August 1, 2006 until their maturity dates February 1, 2014 for the 7.25% Senior Notes and February 1, 2016 for the 7.375% Senior Notes. As of March 31, 2006, we had $3.6 billion in principal outstanding under our Senior Notes.

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

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

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

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

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

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

The terms of the Indentures, among other things, limit our ability and certain of our subsidiaries ability to:

- make restricted payments;
- restrict dividends or other payments of subsidiaries;
- incur additional debt;

engage in transactions with affiliates;

create liens on assets;

engage in sale and leaseback transactions; and

consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries.

Project Financing

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

Note 9 Changes in Capital Structure

As of March 31, 2006, we had 10,000,000 authorized preferred shares, 2,670,000 of which have been issued and are outstanding. The outstanding preferred shares are comprised of: 420,000 of 4% Preferred Stock, 250,000 of 3.625% Preferred Stock and 2,000,000 5.75% Preferred Stock.

5.75% Preferred Stock

On February 2, 2006, we completed the issuance of 2 million shares of 5.75% mandatory convertible preferred stock, or the 5.75% Preferred Stock, at an offering price of $250 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $486 million. Dividends on the 5.75% Preferred Stock are $14.375 per share per year, and are due and payable on a quarterly basis beginning on March 15, 2006. The 5.75% Preferred Stock will automatically convert into common stock on March 16, 2009, or the Conversion Date, at a rate that is dependent upon the applicable market value of our common stock. If the applicable market value of our common stock is $60.45 a share or higher at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 4.1356 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is less than or equal to $48.75 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 5.1282 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is between $48.75 per share and $60.45 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible into common stock at a rate that is prorated between 4.1356 and 5.1282 shares of common stock for every share of 5.75% Preferred Stock.

Common Stock issued to the public

On January 31, 2006, we completed the issuance of 20,855,057 shares of our common stock, or the Common Stock, at an offering price of $48.75 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $986 million.

Stock issued to the Sellers pursuant to the Acquisition Agreement

On February 2, 2006, pursuant to the Acquisition Agreement, we issued 35,406,292 shares to the Sellers. Of this amount, 19,346,788 shares were issued from treasury and 16,059,504 were newly issued shares. Also see Note 4.

Second Lien Structure

Before the Acquisition, Texas Genco LLC s capital structure permitted the grant of second priority liens on its assets as security for their obligations under certain long-term power sales agreements and related hedges. The Credit Agreement for the New Senior Credit Facility and the Indentures, which became effective as of February 2, 2006, allow these arrangements to remain in place. In addition, the new debt instruments also permit us to grant second priority liens on our other assets in the United States in order to secure obligations under power sales agreements and related hedges, within certain limits. NRG uses the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under long term power sales and related hedges.

As of April 24, 2006, our net mark-to-market exposure on the hedges that are subject to the second lien structure was $2.1 billion. The following table summarizes the utilization of the second lien structure as of March 31, 2006:

	12 Months Starting				
	April 1, 2006	**April 1, 2007**	**April 1, 2008**	**April 1, 2009**	**April 1, 2010**
Equivalent Net Sales secured by Second Lien Structure[1]					
In MW	1,610	3,067	2,522	3,028	1,688
As a percentage of net baseload capacity in collateral pool as of February 2, 2006	30%	44%	36%	43%	22%

(1)

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

Table of Contents

Note 10 Equity Compensation

Incentive Compensation Plans

In December 2004, the FASB issued a revision to SFAS 123, or SFAS 123(R) *Share-Based Payment* which requires us to modify our recognition of expense for stock based compensation in the statement of income. We have adopted the requirements of SFAS 123(R) effective January 1, 2006 using the modified prospective approach. The provisions of SFAS 123(R) did not result in a significant change in our compensation expense because we previously recognized compensation expense in our statements of income under SFAS 123. In accordance with SFAS 123(R), we have estimated a forfeiture rate for each of our awards based on the number of instruments expected to vest rather than recording the actual forfeitures as they occur. The elimination of unearned compensation and amounts previously recognized in income related to the application of the new forfeiture rate to outstanding instruments as of January 1, 2006 was immaterial to our results.

Long-Term Incentive Plan, or LTIP

As of March 31, 2006, a total of 4,000,000 shares of our common stock are available for issuance under the LTIP, subject to adjustment in the event of a reorganization, recapitalization, stock split, reverse stock split, stock dividend, and combination of shares, merger or similar change in our structure or our outstanding shares of common stock. NRG s policy for issuing common stock shares upon LTIP award exercise is to issue treasury shares. If there are no treasury shares available, new shares of common stock will be issued. There were 248,465 and 1,355,193 shares of common stock remaining available for grants under our LTIP as of March 31, 2006 and December 31, 2005, respectively.

On April 28, 2006, NRG s shareholders approved an amendment to increase the number of shares available under the LTIP from 4,000,000 to 8,000,000 shares.

Stock Options, or NQSO s

NQSO s granted under the Long-Term Incentive Plan have a three-year graded vesting schedule beginning on the grant date and become exercisable at the end of this requisite service period. As provided for by SFAS 123(R) for share options with graded vesting issued after January 1, 2006, we recognize compensation cost on a straight-line basis over the requisite service period for the entire award. The maximum contractual term is ten years for approximately 600,000 of our outstanding NQSO shares, and six years for the other 1.1 million outstanding. The aggregate intrinsic value for stock options outstanding at March 31, 2006 and March 31, 2005 is approximately $20 million and $11 million, respectively. The aggregate intrinsic value for stock options exercisable at March 31, 2006 and March 31, 2005 is approximately $13 million and $3 million, respectively. The weighted average contractual term for stock options outstanding at March 31, 2006 and March 31, 2005 is 6.1 and 7.4 years respectively. The weighted average contractual term for stock options exercisable at March 31, 2006 and March 31, 2005 is 6.6 and 7.7 years respectively.

The fair value of the stock option grants were estimated on the date of grant using the Black-Scholes option-pricing model. The following table summarizes the assumptions used to measure fair value and shows the change in the outstanding NQSO balance for the three months ended March 31, 2006 and March 31, 2005:

	Shares	Weighted Average Exercise Price	Weighted Average Grant-Date Fair Value Per Share
Outstanding as of December 31, 2004	962,751	$ 23.15	$ 12.15
Granted			
Canceled or Expired			
Exercised			
Outstanding at March 31, 2005	962,751	23.15	12.15

Exercisable at March 31, 2005	288,249	23.14	12.27
Outstanding as of December 31, 2005	1,095,251	25.04	
Granted	671,421	47.39	15.90
Canceled or Expired	(47,800)	35.19	
Exercised	(9,000)	19.90	9.45
Outstanding at March 31, 2006	1,709,872	33.56	
Exercisable at March 31, 2006	591,164	23.24	12.29

Table of Contents

The fair value of NQSO s issued during the three months ended March 31, 2006 were based on the following assumptions:

	Three Months Ended March 31, 2006
Expected Volatility	28.10% -28.42%
Weighted Average Volatility	28.31%
Expected Dividends	
Expected Term (in years)	4
Risk Free Rate	4.30%-4.66%
Forfeiture Rate	8%

We use an expected term of four years for NQSO s based on the simple average of the contractural term and vesting term. Volatility is calculated based on a blended average of NRG and NRG s industry peers historical 2-year stock price volatility data. A forfeiture rate of 8% was calculated for NQSO s based on an analysis of NRG s historical forfeitures, employment turnover, and expected future behavior.

Restricted Stock Units, or RSU s

RSU s granted under the Long-Term Incentive Plan fully vest three years from the date of issuance. To calculate compensation expense, the fair value of the RSU is based on the closing price of our common stock on the date of grant. Such compensation expense, net of forfeitures, is amortized over the three-year requisite service period. We determined two separate forfeiture rates that best represent the employment termination behavior related to issued RSU s, 8% for senior management and 25% for all other employees. The forfeiture rates were based on an analysis of our historical forfeitures, employment turnover, and expected future behavior. The aggregate intrinsic value for non-vested RSU s on March 31, 2006 and March 31, 2005 is $65.3 and $30.1 million respectively.

The following table shows the change in the outstanding RSU balance for the three months ended March 31, 2005 and 2006:

Non-vested Shares	**Shares**	**Weighted Average Grant-Date Fair Value Per Share**
Non-vested as of December 31, 2004	880,994	$ 21.59
Granted	12,250	35.23
Vested		
Canceled	(11,500)	21.84
Non-vested at March 31, 2005	881,744	20.84
Non-vested as of December 31, 2005	1,285,944	27.14
Granted	195,839	47.18
Vested		
Canceled	(39,650)	28.95
Non-vested at March 31, 2006	1,442,133	29.83

Deferred Stock Units, or DSU s

DSU s granted under the LTIP are fully vested at the date of issuance. Compensation expense recorded is the fair value of the DSU based on the closing price of our common stock on the date of grant. For DSU s, compensation expense is fully recognized in the period of grant. The aggregate intrinsic value for DSU s outstanding at March 31, 2006 and March 31, 2005 is approximately $6 and $4 million respectively. The aggregate intrinsic value for DSU s converted for the three months ended March 31, 2006 and March 31, 2005 is $0.2 million and $0.1 million respectively.

The following table shows the change in the outstanding DSU balance for the three months ended March 31, 2005 and 2006:

Table of Contents

	Shares	Weighted Average Grant-Date Fair Value Per Share
Outstanding as of December 31, 2004	60,281	$ 20.31
Granted	50,110	37.85
Conversions	(4,174)	33.12
Canceled or Expired		
Outstanding at March 31, 2005	106,217	28.08
Outstanding as of December 31, 2005	122,184	29.21
Granted	4,054	43.43
Conversions	(3,548)	29.31
Canceled or Expired		
Outstanding at March 31, 2006	122,690	29.68

Performance Units, or PU s

40,900 of our outstanding PU s will be paid out on August 1, 2008 if the Measurement Price, that is the average closing price of our common stock for the ten trading days prior to August 1, 2008, is equal to or greater than the Target Price of $54.50. The payout for each performance unit will be equal to: (i) one share of common stock, if the Measurement Price equals the Target Price; (ii) a pro-rated amount between one and two shares of common stock, if the Measurement Price is greater than the Target Price but less than the Maximum Price of $63.75; and (iii) two shares of common stock, if the Measurement Price is equal to or greater than the Maximum Price. The other 165,432 outstanding PU s will be paid out in the first quarter of fiscal year 2009 if the Measurement Price is equal to or greater than the following Target Prices:

Grant Date	Shares	Target Price	Maximum Price
1/3/06	92,300	$67.37	$ 78.78
2/3/06	52,632	$66.41	$ 77.67
3/1/06	25,000	$61.82	$ 72.29

The fair value of the PU s was estimated on the date of grant using a Monte Carlo stimulation model. Volatility is calculated based on a blended average of NRG and NRG s industry peers 2-year historical stock price volatility data. Compensation expense, net of a 8% forfeiture rate, will be amortized over the three-year requisite service period. The following table shows the change in the outstanding PU balance for the three months ended March 31, 2006 (no PU s were issued during the three months ended March 31, 2005) and summarizes the assumptions and weighted average assumptions used in the fair value model:

Non-vested Shares	**Shares**	**Weighted Average Grant-Date Fair Value Per Share**
Non-vested as of December 31, 2005	44,900	$ 29.87
Granted	169,932	34.62
Vested		
Canceled	(8,500)	32.45

Non-vested at March 31, 2006	206,332	33.68

The aggregate intrinsic value for PU s outstanding March 31, 2006 is approximately $9 million. There were no PU s outstanding as of March 31, 2005. Significant assumptions used during the period PU s:

	Three Months Ended 3/31/2006
Expected Volatility	28.10% -28.42%
Weighted Average Volatility	28.32%
Expected Dividends	
Expected Term (in years)	3
Risk Free Rate	4.30%-4.68%
Forfeiture Rate	8%

23

Table of Contents

Supplemental information:

For the three months ended March 31, 2006 and March 31, 2005 we did not capitalize any equity compensation costs. In addition, we did not recognize a deferred tax asset related to equity compensation because we are under a full valuation allowance for both periods. Cash received for the exercise of all awards was $0.2 million and $0 for the three months ended March 31, 2006 and March 31, 2005 respectively.

The following table summarizes total compensation expense recognized in accordance with FAS 123(R) for the three months ended March 31, 2006 and March 31, 2005 for each of the four types of awards issued under NRG s Long-Term Incentive Plan. Total non-vested compensation cost not yet recognized is also presented as of March 31, 2006:

Award	Compensation Expense Three months ending March 31 2006	2005 (in millions)	Total non-vested Compensation Cost Not Yet Recognized As of March 31, 2006	Weighted average life remaining As of March 31, 2006
Stock Options	0.7	0.9	11.7	1.6
Deferred Stock Units	0.2			
Restricted Stock Units	1.5	1.2	26.8	1.6
Performance Units	0.5		6.3	2.7
Total	$ 2.9	$ 2.1	$ 44.8	

Note 11 Earnings Per Share

Basic earnings per common share were computed by dividing net income less accumulated preferred stock dividends by the weighted average number of common stock shares outstanding. Shares issued during the year are weighted for the portion of the year that they were outstanding. Diluted earnings per share is computed in a manner consistent with that of basic earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period.

Dilutive effect for equity compensation The outstanding non-qualified stock options, non-vested restricted stock units, deferred stock units and performance units are not considered outstanding for purposes of computing basic earnings per share. However, these instruments are included in the denominator for purposes of computing diluted earnings per share under the treasury stock method or the if-converted method. The dilutive effect of the potential exercise of outstanding non-qualified stock options, non-vested restricted stock units and performance units is calculated using the treasury stock method. The dilutive effect of the deferred stock units is included in the denominator for purposes of computing diluted earnings per share under the if-converted method.

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

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

Three Months Ended March 31

	2006	2005
	(In millions, except per share data)	
Basic earnings per share		
Numerator:		
Income from continuing operations	$ 18	$ 22
Preferred stock dividends	(11)	(4)
Net income available to common stockholders from continuing operations	7	18
Discontinued operations, net of tax	8	1
Net income available to common stockholders	$ 15	$ 19

Table of Contents

	Three Months Ended March 31			
	2006		2005	
	(In millions, except per share data)			
Denominator:				
Weighted average number of common shares outstanding		117.4		87
Basic earnings per share:				
Income from continuing operations	$	0.06	$	0.20
Discontinued operations, net of tax		0.07		0.01
Net income	$	0.13	$	0.21
Diluted earnings per share				
Numerator:				
Net income available to common stockholders from continuing operations	$	7	$	18
Add preferred stock dividends for dilutive preferred stock				
Adjusted income from continuing operations		7		18
Discontinued operations, net of tax		8		1
Net income available to common stockholders	$	15	$	19
Denominator:				
Weighted average number of common shares outstanding		117.4		87
Incremental shares attributable to the issuance of non-vested restricted stock units (treasury stock method)		0.8		0.4
Incremental shares attributable to the assumed conversion of deferred stock units (if-converted method)		0.1		0.1
Incremental shares attributable to the issuance of non-vested non-qualifying stock options (treasury stock method)		0.5		0.2
Total dilutive shares		118.8		87.7
Diluted earnings per share:				
Income from continuing operations	$	0.06	$	0.20
Discontinued operations, net of tax		0.07		0.01
Net income	$	0.13	$	0.21

For the three months ended March 31, 2006 and March 31, 2005, options to purchase 595,121 and 727,751 shares of common stock, respectively, were not included in the computation because the effect would be anti-dilutive.

For the three months ended March 31, 2006 and March 31, 2005, outstanding preferred shares which are convertible into 18,771,200 and 10,500,000 shares of common stock, respectively, were not included in the computation because the effect would be anti-dilutive.

Note 12 Segment Reporting

Our identified reportable segments are primarily based on geographic areas, both domestically and abroad. On February 2, 2006 we acquired NRG Texas creating a new segment of operations Wholesale Power Generation Texas.

As of December 31, 2005, interest bearing intercompany debt was issued to certain subsidiaries in the Northeast and South Central segments that resulted in increased interest expense, thus reducing their net income for the three months ended March 31, 2006, by $14 million and $7 million, respectively. During the first quarter of 2005, such interest expense was immaterial.

Table of Contents

Three Months Ended March 31, 2006

	Wholesale Power Generation: Texas	Northeast	South Central	Western	Other North America	Australia	Other International	All Other: Alternative Energy	Non-Generation	Other	Total
	(In millions)										
Operations											
Operating revenues	$ 438	$ 392	$ 172	$	$ 1	$ 54	$ 42	$ 15	$ 51	$ (21)	$ 1,144
Depreciation and amortization	74	22	15		2	6	1	1	3	1	125
Equity in earnings/(losses) of unconsolidated affiliates				(2)	2	6	15				21
Income/(loss) from continuing operations before income taxes	(7)	132	35	(4)	59	7	24	2	13	(243)	18
Net income/(loss) from continuing operations	18	132	35	(2)	58	5	17	2	10	(257)	18
Net income from discontinued operations, net of income taxes					8						8
Net income/(loss)	$ 18	$ 132	$ 35	$ (2)	$ 66	$ 5	$ 17	$ 2	$ 10	$ (257)	$ 26
Total assets	$ 13,044	$ 1,732	964	$ 432	$ 233	$ 851	$ 591	$ 46	$ 894	$ 720	$ 19,507

Three Months Ended March 31, 2005

	Wholesale Power Generation: Northeast	South Central	Western	Other North America	Australia	Other International	All Other: Alternative Energy	Non-Generation	Other	Total
	(In millions)									
Operations										
Operating revenues	$ 332	$ 117	$	$ 1	$ 49	$ 43	$ 15	$ 41	$ (1)	$ 597
Depreciation and amortization	19	15		2	6	1	1	3	1	48
Equity in earnings of unconsolidated affiliates			5	2	6	24				37
Income/(loss) from continuing operations before income taxes	33	9	3	(6)	11	46	1	5	(75)	27

Net income/(loss) from continuing operations	33	9	3	(6)	10	42	1	5	(75)	22
Net income from discontinued operations, net of income taxes				1						1
Net income/(loss)	$ 33	$ 9	$ 3	$ (5)	$ 10	$ 42	$ 1	$ 5	$ (75)	$ 23

Table of Contents

Note 13 Income Taxes

Income tax expense was approximately $0 and $5 million for the three months ended March 31, 2006 and 2005, respectively. The income tax expense for the three months ended March 31, 2006 and 2005 includes domestic tax benefit of approximately $10 million and $0, respectively, and foreign tax expense of approximately $10 million and $5 million, respectively.

A reconciliation of the U.S. statutory rate to our effective tax rate from continuing operations for the three months ended March 31, 2006 and 2005 are as follows:

	Three Months Ended March 31	
	2006	2005
	(Dollars in millions)	
Income From Continuing Operations Before Income Taxes	$ 18	$ 27
Tax at 35%	6	9
State taxes	2	(2)
Foreign operations	(5)	(23)
Valuation allowance	1	20
Disputed claims reserve	(7)	
Permanent differences, reserves, other	3	1
Income Tax Expense	$	$ 5
Effective income tax rate	0%	18.5%

For U.S. income tax purposes, the total U.S. income tax expense for the three months ended March 31, 2006 was approximately $0. The effective income tax rate for the three months ended March 31, 2006 differs from the U.S. statutory rate of 35% due to a property basis difference relating to disbursements from the disputed claims reserve, a net increase in the valuation allowance, subpart F income and dividends, and earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate.

Deferred tax assets and valuation allowance

On a preliminary basis, NRG established deferred tax assets of $1.5 billion and deferred tax liabilities of $2.1 billion in purchase accounting as a result of our acquisition of NRG Texas. During the quarter, domestic net deferred tax assets decreased by $19 million. As a result, we reduced our domestic valuation allowance by $19 million through a reduction to our intangibles of $18 million and a reduction in tax expense of $1 million. As of March 31, 2006, we have NOL carryforwards available for federal income tax purposes of $305 million that expire through 2026. In addition, we have cumulative foreign NOL carryforwards of $151 million that do not have an expiration date.

We believe that it is more likely than not that a benefit will not be realized on a substantial portion of our deferred tax assets. This assessment includes consideration of positive and negative evidence, including our current financial position and results of current operations, projected future taxable income, including projected operating and capital gains, and our available tax planning strategies. Therefore, as of March 31, 2006, a valuation allowance of $703 million was recorded against the net deferred tax assets, comprised of a current and non-current portion of approximately $29 million and $674 million, respectively.

Under SOP 90-7, any future benefits from reducing the valuation allowance established upon emergence from bankruptcy, should first reduce intangibles until exhausted and thereafter be reported as a direct addition to paid-in capital, and not a benefit on our income statement. Consequently, our effective tax rate in post-bankruptcy emergence years will not benefit from the realization of our deferred tax assets, which were fully valued as of the date of our emergence from bankruptcy.

Table of Contents

Note 14 Benefit Plans and Other Postretirement Benefits

Substantially all employees hired prior to December 5, 2003, were eligible to participate in our non contributory, defined benefit pension plans which were initiated effective January 1, 2004, with credit for service from December 5, 2003. In addition, we provide postretirement health and welfare benefits (health care and death benefits) for certain groups of our employees. Generally, these are groups that were acquired in recent years and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements. We expect to contribute approximately $58 million to our pension plans in 2006.

As a result of the acquisition of Texas Genco LLC on February 2, 2006, NRG has assumed responsibility for the liabilities and assets of the Texas Genco LLC pension and retiree welfare plans. The Texas Genco LLC pension plan is a noncontributory defined benefit pension plan that provides cash balance benefits based on all years of service to Texas Genco LLC employees who were employed prior to January 1, 2005. In addition, employees who were hired prior to 1999 are also eligible for grandfathered benefits under a final average pay formula. In most cases, the benefits under the grandfathered formula will be frozen as of December 31, 2008.

The Texas Genco LLC employees are also covered under an unfunded postretirement health and welfare plan. Each year, employees receive a fixed credit of $750 to their account plus interest. Certain grandfathered employees will receive additional credits through 2008. At retirement, the employees may use their accounts to purchase retiree medical and dental benefits from NRG. NRG s costs are limited to the amounts earned in the employee s account; all other costs are paid by the participant.

NRG Energy and NRG Texas Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The net annual periodic pension cost for the three months ended March 31, 2006 and 2005 related to all of our plans, include the following components:

	Pension Benefits Three Months Ended		Other Benefits Three Months Ended	
	March 31, 2006	March 31, 2005	March 31, 2006	March 31, 2005
	(In millions)			
Service cost benefits earned	$ 4	$ 3	$ 1	$
Interest cost on benefit obligation	3	1	1	1
Amortization of net (gain)/loss				
Expected return on plan assets	(1)			
Curtailment gain				
Net periodic benefit cost	$ 6	$ 4	$ 2	$ 1

On February 2, 2006 we completed our acquisition of Texas Genco LLC. Upon consummation of the acquisition Texas Genco LLC became a wholly owned subsidiary of NRG Energy, Inc. The net periodic pension cost relating to the NRG Texas plans included in the table above consist of the following components:

	The period from February 2, 2006 thru March 31, 2006	
	Pension Benefits	Other Benefits
	(In millions)	
Service cost benefits earned	1	

Interest cost on benefit obligation		2	
Amortization of net (gain)/loss			
Expected return on plan assets		(1)	
Net periodic benefit cost	$	2	$

Note 15 Commitments and Contingencies

Lease Commitments

As a result of the acquisition of Texas Genco LLC our operating lease commitments have increased significantly. Such significant increases are primarily due to the anticipated commencement of leases for 2,695 railcars over the next two years. As of March 31, 2006, approximately 540 of these railcars have been delivered and are under lease for future commitments of approximately $61 million.

Coal, Gas and Transportation Commitments

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

		(In millions)
2006	$	481
2007		604
2008		584
2009		556
2010		410
Thereafter		1,745
Total	$	4,380

Legal Issues

Set forth below is a description of our material legal proceedings. Pursuant to the requirements of SFAS 5, *Accounting for Contingencies,* and related guidance, we record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments could occur, there can be no certainty that we 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 material 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 known uncertainty of litigation.

In addition to the legal proceedings noted below, we are parties to other litigation or legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect our consolidated financial position, results of operations or cash flows.

The Company believes that it has valid defenses to the legal proceedings and investigations described below and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified below, the Company is unable to predict the outcome of these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company s consolidated financial position, results of operations or cash flows. The Company also has indemnity rights for some of these proceedings to reimburse the Company 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 arising based on events occurring in the California power market. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market gaming activities. Certain of these lawsuits originally commenced in 2000 and 2001, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Southern District of California. In December 2002, the district court found that federal jurisdiction was absent and remanded the cases back to state court. On December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the district court in most respects. On March 3, 2005, the Ninth Circuit denied a motion for rehearing. On May 5, 2005, the case was remanded to California state court and, under a scheduling order, defendants filed their objections to the pleadings. On July 22, 2005, based upon the filed rate doctrine and federal preemption, the court dismissed NRG Energy, Inc. without prejudice, leaving only subsidiaries of WCP remaining in the case. On October 3, 2005, the court sustained defendants demurrer dismissing the case against all remaining defendants. On December 2, 2005, the plaintiffs filed their notice of appeal from the dismissal with the U.S. Court of Appeals for the Ninth Circuit. 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 the above referenced 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. NRG s February 1, 2006 motion in the U.S. Bankruptcy Court for the Southern District of New York to expunge the pre-bankruptcy California electricity claims filed against the NRG entities that went through chapter 11 remain pending.

FERC Proceedings

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

Connecticut Congestion Charges

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

New York Public Interest Research Group

On October 24, 2005, the U.S. Court of Appeals for the Second Circuit issued its opinion in *New York Public Interest Research Group (NYPIRG) v. Stephen L. Johnson, Administrator, U.S. Environmental Protection Agency.* In 2000, the NYSDEC issued a NOV to the prior owner of the Huntley and Dunkirk stations. After an unsuccessful administrative challenge to the stations Title V air quality permits by NYPIRG, it appealed on October 31, 2003. The Second Circuit held that, during the Title V permitting process for

30

the two stations, the 2000 NOV should have been sufficient for the NYSDEC to have made a finding that the stations were out of compliance. Accordingly, the court stated that the EPA should have objected to the Title V permits on that basis and the permits should have included compliance schedules. On January 12, 2006, the NYSDEC, the EPA and NRG filed individual petitions for rehearing with the Second Circuit. On January 31, 2006, the court denied the petitions of the NYSDEC and EPA. NRG s petition for rehearing en banc was denied on April 20, 2006. On June 3, 2005, the consent decree among NYSDEC, Niagara Mohawk Power Corporation and NRG was entered in federal court, settling the substantive issues discussed by the Second Circuit in its decision. NYSDEC is in the process of incorporating the consent decree obligations into the Huntley and Dunkirk Title V permits so as to make them permit conditions, an action we believe is supported by the Second Circuit s decision.

Station Service Disputes

On October 2, 2000, NiMo commenced an action against NRG in New York state court seeking damages related to NRG s alleged failure to pay retail tariff amounts for utility services at the Dunkirk Plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego Plants. On October 8, 2002, by stipulation and order, this action was stayed pending submission to FERC of some or all of the disputes in the action. The contingent loss from this case is approximately $27 million, and at this time we believe we are adequately reserved. In a companion action at FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo s petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. On April 22, 2005, FERC denied NiMo s motion for rehearing. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on May 12, 2005, consolidated the appeal with several pending station service disputes involving NiMo. All parties filed their briefs prior to the January 17, 2006 deadline, and oral argument was held on April 10, 2006.

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; however, the parties have yet to agree on a description of the dispute and on the appointment of a neutral arbitrator. The contingent loss from this case could exceed $5 million, and at this time we believe we are adequately reserved.

Itiquira Energetica, S.A.

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

CFTC Trading Litigation

On July 1, 2004, the Commodities Futures Trading Commission, or CFTC, filed a civil complaint against NRG in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act. In May 2004, the U.S. Bankruptcy Court presiding over NRG s chapter 11 expunged the CFTC s proof of claim. On March 15, 2005, NRG s motion to dismiss was granted by the federal district court. On May 13, 2005, the CFTC filed a notice of appeal with the U.S. Court of Appeals for the Eighth Circuit. Issues on appeal have been fully briefed and oral argument is scheduled for

May 15, 2006. On November 17, 2004, a bankruptcy court hearing was held on the CFTC s motion to reinstate its expunged bankruptcy claim, and on NRG s motion to enforce the provisions of the NRG plan of reorganization, thereby precluding the CFTC from continuing its federal court action. The bankruptcy court has yet to schedule a hearing or rule on the CFTC s pending motion to reinstate its expunged claim.

Texas Asbestos Litigation

Several of our plants are the subject of lawsuits, primarily commenced in 2001, against numerous defendants by a large number of individuals who claim personal injury due to alleged exposure to asbestos while working at plant sites in Texas. These are premise-based claims as distinguished from product-based claims. The overwhelming majority of these claimants are third party contractor or sub-contractors who participated in the construction, renovation, or repair of various industrial plants, including power plants. As of March 31, 2006, there were 3,526 pending claims. For the three months ending March 31, 2006, there were no new claims filed, three claims were settled, and 90 claims were dismissed or otherwise resolved with no payment. For the first quarter of 2006, the average portion of the settlements for which we had financial responsibility was skewed by having so few settlements, one of which was uncharacteristically large. While ultimate financial responsibility for uninsured losses relating to asbestos claims has been assumed by us, CenterPoint Energy has agreed to continue to indemnify such claims to the extent they are covered by insurance maintained by CenterPoint Energy, subject to reimbursement of the costs of such defense from us. To date, costs of settlement and defense have not been material and a portion of the payments in respect of these claims have been offset by insurance recoveries.

Disputed Claims Reserve

As part of the NRG plan of reorganization, we have 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, we will be obligated to provide additional cash and common stock to the 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 we have surrendered control over the common stock and cash provided to the disputed claims reserve, we recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from our balance sheet. Similarly, we removed the obligations relevant to the claims from our balance sheet when the common stock was issued and cash contributed.

The face amount of the remaining unresolved claims is approximately $35 million, plus unresolved claims relating to the California power crisis in 2000-2001 and other claims of indefinite amount, but the Company estimates that the actual amount of these claims, once settled, will be less than $35 million. On April 3, 2006, the Company made a supplemental distribution to creditors under our Chapter 11 plan totaling $25 million in cash and 2,541,000 shares of common stock. As of April 18, 2006, the reserve held approximately $10 million in cash and approximately 750,000 shares of common stock. We believe this is adequate to ensure sufficient funds to satisfy all remaining disputed claims.

Bourbonnais Agreements

On January 31, 2006, we finalized a stipulation and settlement agreement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001. The stipulation fixes the amount and provides for the allowance of the equipment manufacturer s proof of claim previously filed in NRG s bankruptcy proceeding. The settlement agreement provides for a $6 million payment by NRG to the equipment manufacturer, and the release of all claims NRG Bourbonnais and NRG have for the return of payments made under the 1999 and 2001 turbine purchase agreements. Under the settlement agreement, NRG received certain equipment valued at $55 million as well as a one year option to purchase new-build equipment for a fixed price. During the first quarter of 2006, we recorded approximately $67 million of other income associated with the settlement which resulted from 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.

Note 16 Regulatory Matters

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

Northeast Region

RMR Agreements

FERC accepted revised Reliability Must Run, or RMR, agreements for the Devon, Middleton and Montville stations on February 1, 2006, establishing them effective January 1, 2006, and providing for the continued operation of the stations as RMR facilities. The Devon RMR Agreement will terminate ninety days after the commencement of the Locational Forward Reserve Market, or LFRM, but no earlier than January 1, 2007. On February 6, 2006, ISO-NE filed with FERC its Ancillary Service Market Phase II package that includes its proposed LFRM, seeking an effective date of October 1, 2006, which, if accepted, would trigger the termination of the Devon RMR Agreement as set forth above.

On February 15, 2006, we reported to FERC and to ISO-NE that for two days in January 2006, after unit 12 at the Devon station had been removed from service for needed maintenance, it was erroneously reported to ISO-NE as available. We further reported that when ISO-NE dispatched the Devon units on January 25, 2006, and unit 12 was unable to respond, inaccurate information was provided to ISO-NE. On March 28, 2006, we were advised by FERC that it had commenced a preliminary, non-public, informal investigation into the January 25 ISO-NE dispatch. That same day, FERC also issued to us a data request relating to our New England fleet for the period from March 3, 2003 to the present. We continue to investigate the matter and are cooperating with FERC and ISO-NE. The outcome or impact of this investigation cannot be predicted at this time.

Connecticut

The complaint filed on September 12, 2005 by Richard Blumenthal, Attorney General for the State of Connecticut against ISO-NE seeking to amend the ISO-NE s Market Rule 1 to require all electric generation facilities not currently operating under an RMR agreement in Connecticut to be placed under cost-of-service rates remains pending. The resolution of that complaint may impact revenues from NRG s Connecticut Jet Power and Norwalk facilities which are not currently operating pursuant to an RMR agreement.

New York

The dispute is continuing with respect to high prices for spinning reserves, or SRs, and non-spinning reserves, or NSRs, in the NYISO-administered markets during the period from January 29 to March 27, 2000. Certain entities have argued that the NYISO acted unreasonably in declining to invoke Temporary Extraordinary Operating Procedures, or TEPs, 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, or D.C. Circuit, remanded the case to FERC to further explain its decision not to utilize TEP to remedy certain 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 been appealed to the D.C. Circuit.

On April 19, 2006, a settlement in principle was reached with respect to high prices in the NYISO energy market on May 8 and 9, 2000. Those high prices resulted from bids submitted by the New York Power Authority for its Blenheim-Gilboa facility, a pumped storage unit. Certain parties have challenged NYISO s issuance of an Energy Limited Resources Extraordinary Corrective Action utilizing its TEP authority to reduce the prices and complained to FERC requesting NYISO restore the original real-time market prices. The Commission denied the complaints. In its March 4, 2005 order on remand from the D.C. Circuit, FERC found that NYISO s tariff did not contain a market design flaw, a necessary prerequisite to invoking TEP. FERC therefore ordered NYISO to pay refunds and collect surcharges designed to reinstate the original market clearing prices for energy for the real-time market determined on May 8 and 9, 2000, and to file a refund report; this order was reaffirmed on rehearing. As a result of the settlement in principle, NRG will retain the amounts refunded to it in 2005 and expects to receive additional non-material amounts. All pending appeals will be dropped, terminating the proceeding. The settlement has not yet been documented.

On March 15, 2006, we received the results from NYISO Market Monitoring Unit s review of our Astoria plant s 2004 Generating Availability Data System, or GADS, reporting. We are reviewing this data and working to resolve this matter with the NYISO. This audit may result in the resettlement of NRG's capacity revenues from the Astoria facility due to a redetermination of the amount of available capacity.

On March 21, 2006, the Commission accepted NYISO s proposed revisions to its tariff addressing Black Start and System this audit may result in the resettlement of NRG s capacity revenues from the Astoria facility due to a redetermination of the amount of available capacity. Restoration Services establishing the rate for blackstart services effective October 1, 2005. Our Astoria and Arthur Kill facilities provide such blackstart services and, accordingly, we expect to receive approximately $1 million a year for such services. In connection with the establishment of the new rate going forward, payments for past services were resolved and, in the first quarter, we booked approximately $1.5 million for such services provided prior to October 1, 2005.

On April 3, 2006, the Commission accepted NYISO s proposal to extend its tariff rate for voltage support service, or VSS, that was scheduled to expire on December 31, 2005, but declined to make the existing rate subject to refund, thus continuing the existing rate and resolving the proceeding. As a result, we can expect to receive the same amount of revenues for VSS service team our New York plants in 2006 as was received in 2005.

Western Region

Table of Contents

NRG has RMR agreements with the Cal ISO for one-year terms for 2006 for all of our San Diego generating units. Unit 4 of our Encina generation station was separately designated by Cal ISO as an RMR unit for 2006 on December 22, 2005, and its RMR agreement was filed separately with FERC. FERC accepted its RMR agreement on February 14, 2006, over the protest of a competitor, MMC Energy North America, LLC, or MMC. Although MMC has requested rehearing of FERC s February 14 order, it withdrew its request for rehearing on April 21, 2006.

Note 17 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 our facilities are not exempted from coverage, we could be required to make extensive modifications to further reduce potential environmental impacts. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on our operations.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws impose strict (without fault) and joint and several liability. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial.

As part of acquiring existing generating assets, we have inherited certain environmental liabilities associated with regulatory compliance and site contamination. Often potential compliance implementation plans are changed, delayed or abandoned due to one or more of the following conditions: (a) extended negotiations with regulatory agencies, (b) a delay in promulgating rules critical to dictating the design of expensive control systems, (c) changes in governmental/regulatory personnel, (d) changes in the interpretation and enforcement of existing laws and regulations, (e) changes in governmental priorities or (f) selection of a less expensive compliance option than originally envisioned.

Texas Region

We currently estimate approximately $73 million of capital expenditures will be incurred during the period 2006 through 2011 for our NRG Texas facilities, primarily related to installation of particulate, SO_2, and NO_X controls, as well as studies for installation of BTA under the Phase II 316(b) Rule.

Northeast Region

NRG maintains financial assurance to cover costs associated with landfill closure, post-closure care and monitoring activities. NRG has funded trusts to provide such financial assurance in the amount of approximately $6 million in New York and approximately $7 million in Delaware. NRG must also maintain financial assurance for closing interim status. For this purpose, the Resource Conservation and Recovery Act facilitates and has funded a trust in the amount of approximately $2 million for this purpose.

NRG has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical ash contamination at facilities in the Northeast region. The total estimated cost is not expected to exceed $1.4 million. Other remedial obligations at the Arthur Kill generating station have been established in discussions between NRG and the NYSDEC and are estimated to be approximately $1 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be approximately $3 million. NRG may be required to remediate historical coal tar contamination and/or record a deed restriction on the Astoria property if significant contamination is to remain in place.

As a result of a small 2001 underground fuel line leak at our Vienna Generating Station, NRG submitted a plan for remediation to the Maryland Department of the Environment, or MDE. The MDE has not formally responded. The remediation in connection with this matter is not expected to exceed $1 million.

We currently estimate that we will incur total environmental capital expenditures of approximately $367 million during 2006 through 2011 for our facilities in New York, Connecticut, Delaware and Massachusetts. These expenditures will be primarily related to installation of particulate, SO_2 and NO_X controls, as well as installation of

BTA under the Phase II 316(b) Rule.

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 is working with the Delaware Department of Natural Resources and Environmental Control, or DNREC, through the Voluntary Clean-up Program to investigate the site. Although we are unable to predict the exact impact at this time, we believe the cost to remediate will not be material.

South Central Region

Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by NRG in the amount of approximately $5 million. Annual payments are made to the fund in the amount of approximately $0.1 million.

We currently estimate approximately $252 million of capital expenditures will be incurred during the period 2006 through 2011 for our South Central facilities, primarily related to installation of particulate, SO_2 and NO_X controls, as well as studies for installation of BTA under the Phase II 316(b) Rule.

Western Region

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

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

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

Other North America

Liabilities of our Resource Recovery business associated with closure, post-closure care and monitoring of our Becker refuse derived fuel ash landfill are addressed through the use of a letter of credit maintained by NRG in the amount of approximately $3 million.

Note 18 Guarantees

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

The descriptions below update, and should be read in conjunction with, the complete descriptions under Note 29 Guarantees and Other Contingent Liabilities in NRG s Form 10-K for the year ended December 31, 2005.

With the acquisition of Texas Genco LLC we assumed several guarantee obligations relating to Texas Genco LLC entities. Under these guarantees, NRG Texas has guaranteed the payment obligations of NRG Texas LP (formerly known as Texas Genco II LP) under commercial agreements to various parties. Maximum obligations under these guarantees total $48 million. During the fiscal quarter ending March 31, 2006, we increased our guarantee obligations under other commercial arrangements by $29 million. These pertain to payment obligations of our subsidiary NRG Power Marketing Inc., or PMI.

Table of Contents

On April 12, 2006, in connection with the sale of our interest in a 50% owned subsidiary, we became obligated under an indemnity to the buyer of costs arising from a breach of representations, warranties or covenants contained in the sales agreement. Our maximum exposure is capped at approximately $12 million. We do not believe we will be required to perform under this indemnity.

On March 10, 2006, we executed a guarantee to the benefit of our counterparty under the railcar lease described in Note 15 *Commitments and Contingencies*. This guarantee covers payment and performance obligations of our wholly-owned subsidiary, NRG Texas LP, under the relevant lease documents, and is of indeterminate exposure.

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

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

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

Note 19 Condensed Consolidating Financial Information

As of March 31, 2006, we have $1.2 billion of 7.25% Senior Notes and $2.4 billion of 7.375% Senior Notes outstanding. These notes are guaranteed by each of our current and future wholly-owned domestic subsidiaries, or Guarantor Subsidiaries. Each of the following Guarantor Subsidiaries fully and unconditionally guaranteed the Notes as of March 31, 2006.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Cabrillo Power I LLC
Cabrillo Power II LLC
Capistrano Cogeneration Company
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
NRG Blocker VII Inc.
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Texas LLC
NRG Texas LP
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.

Huntley Power LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Long Beach Generation LLC
Louisiana Generating LLC
Middletown Power LLC
Montville Power LLC
NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
New Genco GP, LLC
New Genco LP, LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations, Inc.
NRG Bayou Cove LLC
NRG Blocker I LP
NRG Blocker II LP
NRG Blocker III Inc.
NRG Blocker IV Inc.
NRG Blocker V Inc.
NRG Blocker VI Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc.
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services LLC
Texas Genco Services, LP
Vienna Operations Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

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

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission s Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the Guarantor Subsidiaries or Non-Guarantor Subsidiaries operated as independent entities.

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Operating Revenues					
Revenues from majority-owned operations	$ 989	$ 142	$ 13	$	$ 1,144
Operating Costs and Expenses					
Cost of majority-owned operations	628	105	10		743
Depreciation and amortization	111	12	2		125
General, administrative and development	22	3	36		61
Total operating costs and expenses	761	120	48		929
Operating Income/(Loss)	228	22	(35)		215
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	22		161	(183)	
Equity in earnings of unconsolidated affiliates		21			21
Write downs and losses on sale of equity method investments	(3)				(3)
Other income, net	3	76	7	(5)	81
Refinancing expenses			(178)		(178)
Interest expense	(54)	(19)	(50)	5	(118)
Total other income/(expense)	(32)	78	(60)	(183)	(197)
Income From Continuing Operations Before Income Taxes	196	100	(95)	(183)	18
Income Tax Expense/(Benefit)	85	36	(121)		
Income From Continuing Operations	111	64	26	(183)	18
Gain on Discontinued Operations, net of income taxes		8			8
Net Income	$ 111	$ 72	$ 26	$ (183)	$ 26

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
March 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer) (In millions)	Eliminations(1)	Consolidated Balance
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 200	$ 137	$ 481	$	$ 818
Restricted cash	3	64			67
Accounts receivable-trade, net	359	58	9		426
Inventory	392	28	2	(10)	412
Derivative instruments valuation	252	15			267
Collateral on deposit in support of energy risk management activities	251				251
Deferred income taxes	6	3	(6)		3
Prepayments and other current assets	107	39	578	(522)	202
Current assets held for sale	11				11
Total current assets	1,581	344	1,064	(532)	2,457
Net property, plant and equipment	10,609	819	24		11,452
Other Assets					
Investment in subsidiaries	730		8,628	(9,358)	
Equity investments in affiliates	36	280			316
Notes receivable, less current portion	76	461	4,158	(4,233)	462
Goodwill	2,748				2,748
Intangible assets, net	1,400	15	5		1,420
Nuclear decommissioning trust	320				320
Derivative instruments valuation	23	1	34		58
Deferred income taxes	1,734	25	(1,732)		27
Other non-current assets	126	58	63		247
Total other assets	7,193	840	11,156	(13,591)	5,598
Total Assets	$ 19,383	$ 2,003	$ 12,244	$ (14,123)	$ 19,507
		LIABILITIES AND STOCKHOLDERS EQUITY			
Current Liabilities					
Current portion of long-term debt and capital leases	$ 460	$ 98	$ 45	$ (467)	$ 136
Accounts Payable	(397)	(135)	878		346

Derivative instruments valuation	483	14			497
Accrued expenses and other current liabilities	290	60	96	(65)	381
Total current liabilities	836	37	1,019	(532)	1,360
Other Liabilities					
Long-term debt	4,159	782	7,114	(4,233)	7,822
Nuclear decommissioning reserve	295				295
Nuclear decommissioning trust liability	299				299
Deferred income taxes	2,393	151	(1,744)		800
Derivative instruments valuation	267	81	28		376
Out-of-market contracts	2,331				2,331
Other long-term obligations	336	60	11		407
Total non-current liabilities	10,080	1,074	5,409	(4,233)	12,330
Total liabilities	10,916	1,111	6,428	(4,765)	13,690
Minority interest		1			1
3.625% Preferred Stock			246		246
Stockholders Equity	8,467	891	5,570	(9,358)	5,570
Total Liabilities and Stockholders Equity	$ 19,383	$ 2,003	$ 12,244	$ (14,123)	$ 19,507

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
	(In millions)				
Cash Flows from Operating Activities					
Net income/(loss)	$ 111	$ 72	$ 26	$ (183)	$ 26
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates and consolidated subsidiaries	22	(12)	161	(183)	(12)
Depreciation and amortization	111	12	2		125
Amortization of financing costs and debt discount		2	8		10
Write-off of deferred financing costs and debt premium			47		47
Deferred income taxes	28	3	15		46
Unrealized (gains)/losses on derivatives	(52)	(2)	4		(50)
Nuclear decommissioning liability	(3)				(3)
Gain on sale of discontinued operations		(10)			(10)
Write down and loss on sale of equity method investments	3				3
Gain on Bourbonnais legal settlement		(67)			(67)
Changes in collateral deposits	230				230
Amortization of power contracts and emission credits	3	6			9
Amortization of unearned equity compensation			3		3
Cash provided by(used by) changes in other working capital, net of dispositions affects	(287)	36	(106)	366	9
Net Cash Provided by Operating Activities	166	40	160		366
Cash Flows from Investing Activities					

Acquisition of Texas Genco LLC and WCP			(4,288)		(4,288)
Decrease/(increase) in restricted cash		(3)			(3)
Proceeds from sales of nuclear decommissioning trust fund securities	45				45
Investments in nuclear decommissioning trust fund securities	(42)				(42)
Proceeds from sale of investments	45				45
Decrease/(increase) in notes receivable		8	(2,760)	2,760	8
Capital expenditures	(32)	(3)			(35)
Proceeds from sale of discontinued operations		15			15
Net Cash Provided (Used) by Investing Activities	16	17	(7,048)	2,760	(4,255)
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt	2,760		7,175	(2,760)	7,175
Proceeds from issuance of common stock			986		986
Payments for dividends			(10)		(10)
Deferred debt issuance costs			(164)		(164)
Proceeds for preferred share issuance			486		486
Funded letter of credit			350		350
Principal payments on short and long-term debt	(2,735)	(12)	(1,876)		(4,623)
Net Cash Provided (Used) by Financing Activities	25	(12)	6,947	(2,760)	4,200
Effect of Exchange Rate Changes on Cash and Cash Equivalents		1			1
Change in Cash from Discontinued Operations					
Net Increase (Decrease) in Cash and Cash Equivalents	207	46	59		312
Cash and Cash Equivalents at Beginning of Period	(7)	91	422		506
Cash and Cash Equivalents at End of Period	$ 200	$ 137	$ 481	$	$ 818

(1) All significant intercompany

transactions
have been
eliminated in
consolidation.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer) (In millions)	Eliminations[1]	Consolidated Balance
		ASSETS			
Current Assets					
Cash and cash equivalents	$ (7)	$ 91	$ 422	$	$ 506
Restricted cash	3	61			64
Accounts receivable-trade, net	214	275	(205)		284
Current portion of notes receivable		25	468	(468)	25
Taxes receivable	(2)		45		43
Inventory	232	27	1		260
Derivative instruments valuation	385	16	3		404
Collateral on deposit in support of energy risk management activities	438				438
Deferred income taxes	6	3	(5)		4
Prepayments and other current assets	65	22	38		125
Assets held for sale	8		35		43
Current assets discontinued operations		1			1
Total current assets	1,342	521	802	(468)	2,197
Net property, plant and equipment	2,176	832	31		3,039
Other Assets					
Investment in subsidiaries	787		1,774	(2,561)	
Equity investments in affiliates	243	360			603
Notes receivable	76	457	1,398	(1,473)	458
Intangible assets, net	238	19			257
Derivative instruments valuation	18	4			22
Funded letter of credit			350		350
Deferred income taxes		26			26
Other assets	22	20	83		125
Non current assets discontinued operations		354			354
Total other assets	1,384	1,240	3,605	(4,034)	2,195
Total Assets	$ 4,902	$ 2,593	$ 4,438	$ (4,502)	$ 7,431

LIABILITIES AND STOCKHOLDERS EQUITY

Current Liabilities					
Current portion of long-term debt	$ 459	$ 96	$ 14	$ (468)	$ 101
Accounts Payable	158	89	21		268
Derivative instruments valuation	678	14			692
Other bankruptcy settlement		3			3
Accrued expenses and other current liabilities	60	48	69		177
Current liabilities discontinued operations		115			115
Total current liabilities	1,355	365	104	(468)	1,356
Other Liabilities					
Long-term debt	1,397	791	1,866	(1,473)	2,581
Deferred income taxes	37	149	(51)		135
Derivative instruments valuation	25	92	20		137
Out-of-market contracts	298				298
Other long-term obligations	126	58	22		206
Non-current liabilities discontinued operations		240			240
Total non-current liabilities	1,883	1,330	1,857	(1,473)	3,597
Total liabilities	3,238	1,695	1,961	(1,941)	4,953
Minority interest		1			1
3.625% Preferred Stock			246		246
Stockholders Equity	1,664	897	2,231	(2,561)	2,231
Total Liabilities and Stockholders Equity	$ 4,902	$ 2,593	$ 4,438	$ (4,502)	$ 7,431

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In millions)		
Operating Revenues					
Revenues from majority-owned operations	$ 451	$ 134	$ 13	$ (1)	$ 597
Operating Costs and Expenses					
Cost of majority-owned operations	338	106	9	(1)	452
Depreciation and amortization	33	13	2		48
General, administrative and development	11	8	31		50
Corporate relocation charges			3		3
Total operating costs and expenses	382	127	45	(1)	553
Operating Income/(Loss)	69	7	(32)		44
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	45		79	(124)	
Equity in earnings of unconsolidated affiliates	7	30			37
Other income, net	1	22	3		26
Refinancing expenses		10	(35)		(25)
Interest expense		(15)	(40)		(55)
Total other income/(expense)	53	47	7	(124)	(17)
Income From Continuing Operations Before Income Taxes	122	54	(25)	(124)	27
Income Tax Expense/(Benefit)	46	7	(48)		5
Income From Continuing Operations	76	47	23	(124)	22
Loss on Discontinued Operations, net of Income Taxes		1			1
Net Income	$ 76	$ 48	$ 23	$ (124)	$ 23

(1)

All significant intercompany transactions have been eliminated in consolidation.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 76	$ 48	$ 23	$ (124)	$ 23
Adjustments to reconcile net income to net cash provided by operating activities					
Distribution s in excess of (less than) equity earnings of unconsolidated affiliates and consolidated subsidiaries	(52)	(25)	77	(32)	(32)
Depreciation and amortization	33	13	2		48
Amortization of financing costs and debt discount		1	1		2
Write-off of deferred financing costs and debt premium		(9)	1		(8)
Deferred income taxes and investment tax credits	(27)	(2)	23		(6)
Unrealized (gains)/losses on derivatives	76	11	(83)	81	85
Minority interest					
Amortization of power contracts and emission credits	8	3			11
Amortization of unearned equity compensation	1		1		2
Cash provided by(used by) changes in other working capital, net of dispositions affects	(23)	18	26	(82)	(61)
Net Cash Provided by Operating Activities	92	58	71	(157)	64
Cash Flows from Investing Activities					
Decrease in restricted cash and trust funds		34			34
Decrease/(increase) in notes receivable	4	56	(33)	41	68
Capital expenditures	(8)	(3)			(11)
		1			1

Return of capital from equity investments					
Net Cash Provided (Used) by Investing Activities	(4)	88	(33)	41	92
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt	38	206		(41)	203
Payments for dividends	(150)	(7)	(4)	157	(4)
Deferred debt issuance costs		(1)			(1)
Payment for preferred share issuance cost					
Principal payments on short and long-term debt		(281)	(418)		(699)
Net Cash Used by Financing Activities	(112)	(83)	(422)	116	(501)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		(2)			(2)
Change in Cash from Discontinued Operations		(2)			(2)
Net Increase (Decrease) in Cash and Cash Equivalents	(24)	59	(384)		(349)
Cash and Cash Equivalents at Beginning of Period	156	236	712		1,104
Cash and Cash Equivalents at End of Period	$ 132	$ 295	$ 328	$	$ 755

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

Table of Contents

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

Introduction and Overview

NRG Energy, Inc., or NRG Energy , the Company , we , our , or us is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. Our principal domestic generation assets consist of a diversified mix of natural gas, coal, oil-fired and nuclear facilities, representing approximately 45%, 34%, 16% and 5% of our total domestic generation capacity, respectively. In addition, 12% of our domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option.

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

- *Introduction and Overview* section which provides a description of our business segments;
- *Strategy* section;
- *Business Environment* section, including how regulation, weather, and other factors affect our business; and
- *Critical Accounting Policies* section.

Critical accounting policies are the accounting policies that are most important to the portrayal of our financial condition and results of operations and require management s most difficult, subjective, or complex judgment. Our 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.

In this discussion and analysis, we explain the general financial condition and the results of operations for NRG, including:

- factors which affect our business;
- our earnings and costs in the periods presented;
- changes in earnings and costs between periods;
- sources of earnings;
- impact of these factors on our 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 our Consolidated Statements of Income which present the results of our operations for the quarter ended March 31, 2006 and 2005. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- We describe changes to our business environment during the period;
- We highlight significant events that occurred in 2006 that are important to understanding our results of operations;

We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment;

We review our financial condition, addressing our sources and uses of cash, capital resources, commitments, and liquidity; and

We discuss known trends that will affect our results of operation and financial condition in the future.

Changes in Accounting Standards

See Note 2 to the Condensed Consolidated Financial Statements as found in Item 1 for a discussion of recent accounting developments.

Business Environment

With the evolving regulatory environment surrounding increasing competition, and the growth of our merchant energy business, various factors affect our financial results. In addition to those discussed in Item 7 of our annual report on Form 10-K, the following factors affect our business:

Environmental Matters

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

The USEPA issued rules adding Delaware and New Jersey to the Clean Air Interstate Rule (CAIR) because emissions from their states contribute to non-attainment of the fine particle pollution (PM2.5) National Ambient Air Quality Standards in other states. The USEPA also reconfirmed its position on five contested CAIR issues including striking down the pollution control project (PCP) exclusion under the NSR regulations.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap-and-trade greenhouse gas program for electric generators, referred to as the Regional Greenhouse Gas Initiative, or RGGI. Maryland has now announced its intent to join as well. In March 2006, the states participating in RGGI released a draft model rule to be adopted by the states.

We also discuss details of our environmental matters in Item 1 Note 17 to our Condensed Consolidated Financial Statements. Some of this information is about costs that may be material to our financial results.

Regulatory Matters

On March 7, 2006, a broad group of New England market participants filed a proposed settlement of the contested Location Installed Capacity proceeding with FERC. The settling parties include suppliers, load-serving entities, state regulators, and ISO-NE. The settlement provides for interim capacity transition payments for all generators in New England and the establishment of a Forward Capacity Market, or FCM. The FCM established by the settlement will operate an annual descending clock forward capacity auction, by which ISO-NE will obtain the installed capacity requirement of New England, normally three years in advance. In addition to the forward capacity auction, there will be reconfiguration auctions held annually, monthly and seasonably at which capacity obligations can be sold, bought, or exchanged. For our Connecticut units subject to RMR Agreements, any transition payment will be credited against the monthly availability payment for those units, resulting in no additional revenues for those units. Our other New England generation units are expected to be eligible for the transition payments, and thus we expect the transition period to be net positive as compared to the status quo. The FCM should provide a competitive market price for all our capacity, while enhancing opportunities for NRG to competitively repower its New England facilities. The Settlement Judge issued his report on the settlement to FERC on April 11, 2006, and the settlement remains pending before FERC.

The Installed Reserve Margin, or IRM, in New York is determined by the New York State Reliability Council. Based upon the IRM, the NYISO determines the locational capacity requirements, or LCRs. On April 3, 2006, the NYISO determined that certain errors in the data and analysis required it to lower the New York City LCR from 83% to 80%. Because our in-city capacity was and continues to be subject to price caps, we do not expect this action to have a material effect on revenues.

We also discuss details of our regulatory proceedings in Item 1 Note 15 and 16 to our Condensed Consolidated Financial Statements. Some of this information is about costs that may be material to our financial results.

Results of Operations

The following tables provide selected financial information by segment for the three months ended March 31, 2006 and 2005:

	For the three months ended March 31, 2006							
	Texas[4]	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In millions)				
Energy revenue	$ 202	$ 223	$ 109	$	$	$ 44	$ 21	$ 599
Capacity revenue	165	58	48				20	291
Alternative revenue							52	52
O & M fees							3	3
Hedging and Risk Management Activities	(2)	49	5			7		59
Contract amortization	40		4			(6)		38
Other revenues	33	62	6		1	9	(9)	102
Operating revenues	438	392	172		1	54	87	1,144
Cost of energy	250	126	90			19	49	534
Other operating expenses [1]	95	93	21	2	2	25	32	270
Depreciation and amortization	74	22	15		2	6	6	125
Operating income/(loss)	18	150	46	(2)	(3)	4	2	215
MWh sold[2] (in thousands)	7,313	3,261	2,800	386	28	1,290		15,078
Market indicators:								
Average natural gas price Henry Hub ($/MMbtu)								$ 7.69
Average on-peak market power prices ($/MWh)	$ 53.85	$ 72.99	$ 54.05	$ 56.66	$ 48.91			
Cooling Degree Days, or CDDs[3]			114					
CDD s 30 year rolling average			80	7	1			
Heating Degree Days, or HDDs[3]		5,482	946	1,434	2,740			
HDD s 30 year rolling average		6,187	1,270	1,419	3,227			

	For the three months ended March 31, 2005						
	Northeast	**South Central**	**Western**	**Other North America**	**Australia**	**All Other**	**Total**
				(In millions)			
Energy revenue	$ 276	$ 69	$	$ 1	$ 32	$ 20	$ 398
Capacity revenue	65	45		2		22	134
Alternative revenue				1		48	49
O & M fees						5	5
Hedging and Risk Management Activities	(32)				15	1	(16)

Contract amortization		3		(3)	(7)		(7)
Other revenues	23				9	2	34
Operating revenues	332	117		1	49	98	597
Cost of energy	189	67		1	23	49	329
Derivative cost of energy	(4)						(4)
Other operating expenses [(1)]	95	24	1	6	22	28	176
Depreciation and amortization	19	15		2	6	6	48
Operating income/(loss)	34	12	(1)	(9)	(3)	11	44
MWh sold[(2)] (in thousands)	4,175	2,536	475	33	1,352		8,571
Market indicators:							
Average natural gas price Henry Hub ($/MMbtu)							$ 6.44
Average on-peak market power prices ($/MWh)	$ 71.48	$ 48.90	$ 54.71	$ 49.58			
Cooling Degree Days, or CDDs[(3)]		82	3				
CDD s 30 year rolling average		80	7	1			
Heating Degree Days, or HDDs[(3)]	6,374	1,048	1,316	3,113			
HDD s 30 year rolling average	6,187	1,270	1,419	3,227			

(1) Other operating expenses include Cost of majority-owned operations and General, administrative and development expenses, excluding cost of energy.

(2) Includes MWhs sold for wholly owned subsidiaries only.

(3) 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.

(4) Financial information for the results of operations for the Texas segment are for the period of February 2, 2006 to March 31, 2006 only.

Table of Contents

For the benefit of the following discussions, the following table represents the results of NRG excluding the impact of NRG Texas for the three months ended March 31, 2006:

	For the three months ended March 31 2006			2005
	Consolidated	NRG Texas[4]	Total excluding NRG Texas	Total
	(In millions)			
Energy revenue	$ 599	$ 202	$ 397	$ 398
Capacity revenue	291	165	126	134
Alternative revenue	52		52	49
O & M fees	3		3	5
Hedging and Risk Management Activities	59	(2)	61	(16)
Contract amortization	38	40	(2)	(7)
Other revenues	102	33	69	34
Operating revenues	1,144	438	706	597
Cost of energy	534	250	284	329
Derivative cost of energy				(4)
Other operating expenses	270	95	175	176
Depreciation and amortization	125	74	51	48
Operating income	215	18	197	44

(4) Financial information for the results of operations for the Texas segment are for the period of February 2, 2006 to March 31, 2006 only.

Management s discussion of our results of operations for the three months ended March 31, 2006 and 2005

Significant Events Reflected in our Results of Operations for the three months ended March 31, 2006

On February 2, 2006, NRG acquired Texas Genco LLC. Texas Genco LLC is now a wholly-owned subsidiary of NRG, and is managed and accounted for as a new business segment referred to as NRG Texas.

On March 31, 2006, NRG acquired Dynegy s 50% ownership interest in WCP (Generation) Holdings, Inc., or WCP, and became the sole owner of WCP s 1,808 MW of generation in Southern California. The results of operations of WCP will be consolidated as of April 1, 2006. For the three months ended March 31, our 50% ownership WCP was recorded as equity earnings.

Total generation increased for the quarter by 72% primarily due to the addition of NRG Texas to the portfolio. Excluding NRG Texas, generation decreased by 9% as compared to the first quarter of 2005.

As compared to the three months ended March 31, 2005, oil spreads were compressed as our spark and dark spreads widened. This was due to the changes in power and fuel costs as on-peak electricity prices in NY and NEPOOL decreased between 0.3% and 9% while on-peak electricity prices in PJM and Entergy increased between 4.7% and 11.2%. This compares to gas and oil price increases of 21% and 47% respectively, while domestic coal costs, which are largely contracted, were relatively flat.

An unseasonably mild winter lowered demand for our peaking assets as compared to last year. The mild weather and decreased demand lowered the price of power in the Northeast and drove the net domestic mark-to-market gains of $29 million primarily associated with forward financial electric sales in support of our Northeast assets.

We sold $57 million in excess emission allowances; we did not sell any emission allowances in the first quarter of 2005.

On January 31, 2006, we finalized a settlement agreement with an equipment manufacturer related to certain turbine purchase agreements. Upon finalization of the settlement, NRG recorded a total of $67 million of other income, of which $35 million was related to the discharge of accounts payable previously recorded and $32 million related to the recording of the equipment at fair value.

We closed the sale of Audrain to AmerenUE for a total purchase price of $115 million and a net gain of $10 million.

We recorded $178 million in refinancing costs and $63 million in higher interest expense due to new debt facilities associated with the acquisition of Texas Genco.

Consolidated Discussion:

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $1,144 million for the three months ended March 31, 2006, compared to $597 million for the three months ended March 31, 2005. Revenues for the three months ended March 31, 2006, included $599 million of energy revenues compared to $398 million of energy revenues for the three months ended March 31, 2005. Of the $599 million, 59% are merchant revenues; in the first quarter of 2005, 87% of our energy revenues were merchant. These favorable results versus 2005 were largely driven by the acquisition of Texas Genco LLC, which contributed $202 million of energy revenues to the first quarter 2006, including $40 million of revenues associated with contract amortization from out-of-market power contracts. When comparing results of NRG excluding Texas, 2006 energy revenues were $1 million lower as compared to the 2005 results. This decrease is primarily related to the Hedging and Risk Management results. In 2006, excluding Texas, we recorded a $31 million gain associated with the domestic forward mark-to-market value of power and fuel sales. This $31 million compares to a $40 million loss recorded in the first quarter of 2005. Northeast merchant energy revenues decreased quarter over quarter by $62 million as total generation from our Northeast assets decreased 22%, led primarily by the Northeast oil assets, whose generation decreased by 90% as compared to the first quarter of 2005. Lower Northeast energy was partially offset by $39 million in higher energy revenues from our South Central region due to higher power prices, improved unit performance and outages at competitor facilities. Capacity revenues for the three months ended March 31, 2006 were $291 million compared to $134 million for the three months ended March 31, 2005, with the increase driven by NRG Texas s $165 million in capacity revenues. As compared to the first quarter 2005, capacity revenues for NRG excluding NRG Texas decreased due to a net one-time $11 million increase in the first quarter of 2005 related to the Connecticut RMR settlement.

Other revenues include emission allowance sales, natural gas sales, and expense recovery revenues. For the three months ended March 31, 2006, other revenues increased by $68 million from $34 million in the first quarter of 2005 to $102 million in the first quarter of 2006. Of this increase $57 million is related to the sale of our excess SO_2 emission allowances to third parties.

Hedging and Risk Management Activity

	For the three months ended March 31, 2006							
	Texas	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions)							
Net gains/(losses) on settled positions, or financial revenues		(1)	3			8		10
Mark-to-market results								
Reversal of previously recognized unrealized gains/(losses) on settled positions		21						21
Net unrealized gains/(losses) on open positions related to economic hedges	(2)	31						29
Net unrealized gains/(losses) on open positions related to trading activity		(1)						(1)
Subtotal mark-to-market	(2)	51						49

results

Total derivative gain/(loss)	(2)	50	3	8	59

Hedging and Risk Management Activity The total derivative gain for the quarter was approximately $59 million, comprised of $10 million in financial revenue gains and $49 million of mark-to-market gains. The $10 million gain of financial revenues represents the settled value for the quarter of financial instruments that were not afforded hedge accounting treatment. Of the $49 million of mark-to-market gains, $29 million represents the change in fair value of forward sales of electricity and fuel, and $21 million represents the reversal of mark-to-market losses which ultimately settled as financial revenues. Additionally, we recognized a $1 million loss associated with our trading activity. These activities primarily support our Northeast assets.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues (which are recorded net of financial instruments hedges that are afforded hedge accounting treatment) and costs of energy. Over the course of 2005, we hedged much of our calendar year 2006 Northeast generation. Since that time, the settled and forward prices of electricity decreased, resulting in the recognition of mark-to-market forward sales and the settlement of such positions as gains.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the year ended March 31, 2006 was $743 million or 65% of revenues from majority-owned operations. Cost of majority-owned operations for the year ended March 31, 2005 was $452 million or 76% of revenues from

Table of Contents

majority-owned operations. The absolute increase and related percentage decrease is due to NRG Texas, whose cost of majority-owned operations totaled $327 million, or 75% of their total revenues (which included $40 million of contract amortization). Cost of energy increased by $205 million, from $329 million to $534 million. The increase in the cost of energy was driven by NRG Texas, whose cost of energy totaled $250 million. Excluding NRG Texas, NRG s cost of energy decreased by $45 million. This decrease was primarily due to $60 million in lower cost of energy at our Northeast assets $79 million due to lower oil and gas fuel costs as generation from our oil- and gas-fired assets decreased and $12 million in higher coal costs as generation from the Northeast coal-fired plants increased. The Northeast decrease in cost of energy was offset by South Central s cost of energy, which increased by $23 million. The increase at South Central is due to $22 million in higher purchased energy, as the region entered into more tolling agreements and had greater contract commitments. A number of local competitors in South Central experienced outages and purchased power from the South Central units to meet their obligations.

Other Operating Expenses during the first quarter of 2006 totaled $270 million versus $176 million in the comparable period of 2005, an increase of $94 million. This increase is driven by NRG Texas s other operating expenses of $95 million, as major maintenance projects, property taxes, and labor-related costs were relatively flat at most of the other regions.

Depreciation and Amortization

Our depreciation and amortization expense for the three months ended March 31, 2006 and 2005 was $125 million and $48 million, respectively. The increase in depreciation and amortization from 2006 to 2005 is due to the acquisition of Texas Genco LLC.

General, Administrative and Development

Our general, administrative and development, or G&A, costs for the three months ended March 31, 2006 were $61 million or 5% of operating revenue compared to $50 million or 8% of operating revenue for the three months ended March 31, 2005. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees. G&A cost at NRG Texas totaled $11 million, excluding corporate allocation, representing the primary driver of the overall increase in G&A. Of the total $61 million, corporate costs represent $26 million and increased by $2 million due to a bad debt allowance related to the sale of Audrain and $2 million in Texas-integration related costs. These increases were offset by lower insurance and lower Sarbanes-Oxley compliance costs.

Equity in Earnings of Unconsolidated Affiliates

During the three months ended March 31, 2006, we recorded $21 million of equity earnings from our investments in unconsolidated affiliates as compared to $37 million for the three months ended March 31, 2005. The decrease is due to $16 million of equity earnings from our Enfield investment, which we sold on April 1, 2005. First quarter 2005 results for Enfield included approximately $12 million of unrealized gain associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with FAS 133. Our investment in West Coast Power comprised $1 million for the first quarter of 2006 as compared to $4 million for the first quarter of 2005, with the decrease due to the absence of an RMR agreement with the California ISO for El Segundo, coupled with lower RMR fixed cost recovery by Encina units 4 and 5 in 2006 versus the same period last year. Additionally, our Saguaro investment s earnings decreased by $4 million, as its gas supply contract expired in mid 2005 requiring the plant to purchase gas in the spot market. These decreases were offset by $5 million in higher earnings from our MIBRAG investment $1 million due to the adoption of EITF 04-6 for overburden accounting and $2 million due to the adoption of EITF 05-5 resulting in a reduction to the pension retirement liability with the balance due to lower operating costs.

Write Downs and Losses on Sales of Equity Method Investments

NRG expects to sell its 50% interest in James River in the second quarter of 2006. As a result of this transaction, we recorded a write down in the value of the equity investment of approximately $3 million to reduce the carrying value of our interest. We did not incur any write downs or losses on sales of equity method investments for the three months ended March 31, 2005.

Other income, net

During the three months ended March 31, 2006 and 2005, we recorded other income of $81 million and $26 million, respectively. We recorded $67 million in other income associated with the settlement agreement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001. As part of this settlement, NRG received certain equipment valued at $55 million as well as a one-year option to purchase new-build equipment for a fixed price. The $67 million of other income was the result of the discharge of an outstanding $35 million liability, and recording the equipment at its fair value, resulting in $32 million of additional income. See also Note 15 *Commitments and Contingencies* for further discussion of the settlement agreement.

Other income in 2005 was favorably impacted by a $14 million gain from the settlement related to our TermoRio project in Brazil. We also realized a contingent gain of $4 million related to the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. The balance of the favorable increase in other income as compared to the first quarter of 2005 is due to higher interest income related to more efficient management of our cash balances.

Refinancing expense

Refinancing expense for the three months ended March 31, 2006 and 2005 was $178 million and $25 million, respectively. In the first quarter of 2006, we acquired NRG Texas for a purchase price of approximately $6.2 billion. We partially financed this purchase through the issuance of new debt facilities, and retired our previous debt facilities. Of the $178 million of refinancing expense for the quarter, $126 million was related to the premium paid to the previous debt holders, $33 million for the amortization of the bridge loan commitment entered into on September 30, 2005, $31 million related to the write-offs of deferred financing costs associated with the previous debt, and a credit of $14 million related to a debt premium write off.

In the first quarter 2005, we redeemed and purchased a total of $416 million of our Second Priority Notes. As a result of the redemption and purchases, we recorded a total of $34.8 million in fees, write-offs of deferred financing costs and premiums received from the bond issuance, and premium fees we paid for the redeemed and purchased bonds. Additionally, we refinanced the debt of our Flinders project in Australia during the first quarter 2005 which resulted in a credit of $9.8 million for the write-off of debt premium.

Interest expense

Interest expense for the three months ended March 31, 2006 was $118 million, as compared to $55 million for the three months ended March 31, 2005. Interest expense increased due to the financing for the acquisition of Texas Genco LLC. See Note 4 and 8 of the condensed consolidated financial statements for a full description of the acquisition and the financing thereof. As part of the refinancing, we replaced our previous senior secured term loan with a new $3.575 billion senior secured term loan. Additionally, we retired $1.1 billion of our Second Priority Notes with 8% interest rate and issued $3.6 billion senior unsecured notes with a weighted average interest rate of 7.33%.

In the first quarter of 2006, we entered into forward starting interest rate swaps with the objective of fixing the interest rate on a portion of our new Senior Credit Facility. These swaps were designated as cash flow hedges under FAS 133, and any impact associated with ineffectiveness was immaterial to our financial results. For the three months ended March 31, 2006 we had deferred gains of $35 million in other comprehensive income. See Note 8 *Long-term Debt and Capital Leases,* to our condensed consolidated financial statements for further details of these interest rate swaps.

Additionally, we designated an existing fixed-to-floating interest rate swap, previously a hedge of the Second Priority Notes, into a fair value hedge of the new Senior Notes which we closed on February 2, 2006 and recognized $3 million in ineffectiveness associated with this hedging relationship during the quarter. We do not foresee any ineffectiveness for this hedging relationship in the future.

Income Tax Expense

Income tax expense was approximately $0 and $5 million for the three months ended March 31, 2006 and 2005, respectively. The overall effective tax rate decreased to 0% from 18.5% for the three months ended March 31, 2006 and 2005, respectively. The decrease in the Company s effective tax rate from the federal statutory rate of 35% was primarily due to a property basis difference relating to disbursements from the disputed claims reserve, a net increase in the valuation allowance, sub part F income and dividends, and due to earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

During the quarter, we acquired Texas Genco LLC and have included its financial results in the consolidated tax expense and have preliminarily established deferred tax assets of $1.5 billion and deferred tax liabilities of $2.1 billion in purchase accounting.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the establishment of a post Fresh Start accounting valuation allowance in accordance with SFAS 109. The same and other factors, including our history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Gain from Discontinued Operations, net of Income Taxes

We classified as discontinued operations those operations and related gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the three months ended March 31, 2006, we recorded a net gain on sale from discontinued operations of $10 million related to the sale of Audrain. During the three months ended March 31, 2005, discontinued operations totaled a gain of $1 million associated with the various expenses related to McClain to effect its liquidation.

Table of Contents

Texas Region Results

Operating Income

For the period ended March 31, 2006, operating income for NRG Texas was $18 million and includes the results of operations for the two months of NRG ownership, from February 2, 2006 through March 31, 2006. Total generation for the quarter for the NRG Texas was 6.5 million MWh, nearly doubling NRG domestic generation quarter over quarter results. Total sales volumes for the period for NRG Texas totaled 7.3 million MWh of which 89% were sold under long-term sales agreements. The difference between MWh sold and MWh generated, represents MWh purchased from the marketplace.

Revenues

Revenues from our NRG Texas region totaled $438 million for the period ended March 31, 2006. Revenues included $202 million in energy revenues, offset by $2 million of financially settled hedge losses. Capacity revenues totaled $165 million from PCU of which $66 million was related to our investment in the STP nuclear generation facility. Additionally, NRG Texas recorded $40 million of contract amortization related to out of market contracts assumed upon acquisition.

Hedging and Risk Management Activity The total derivative loss for the quarter was $2 million, reflecting the partial ineffectiveness of our forward hedge positions.

Cost of energy

Cost of energy at NRG Texas was $250 million for the period ended March 31, 2006. Coal and lignite costs were $75 million for the period, gas fuel costs were $52 million and nuclear fuel-related expenses were $4 million. These costs directly relate to the generation from our coal-fired, nuclear-fired and gas-fired units. Coal costs include $11 million of lignite coal used at the Limestone coal plant. Purchased energy totaled $48 million or $62 per megawatt/hour and represents the cost to procure additional MWh s to cover our contracted obligations during planned outages in the period.

Other Operating Expenses

Other operating expenses for our Texas region for the period ended March 31, 2006 was $95 million or 22% of the region s revenues. These costs include $66 million of operating and maintenance costs and $11 million of property tax expense. Additionally, NRG Texas incurred $18 million of G&A expense, of which $8 million was related to corporate allocations.

Northeast Region Results

Operating Income

For the period ending March 31, 2006, operating income for the Northeast region was $150 million, as compared to $34 million for the period ended March 31, 2005, a $116 million increase. Of this increase, $62 million is due to the sale of emission allowance credits to external and inter-company parties. Additionally, $71 million of the increase is due to the MtM impacts the Northeast recorded a net $31 million gain associated with forward sales of electricity as compared to a $40 million loss in the first quarter of 2005. With oil prices generally increasing at greater rates than power prices, the Northeast oil spreads were compressed this quarter versus last quarter, while the spark and dark spreads widened. Yet, offsetting the widening spark and dark spreads was the unseasonably mild weather during the first quarter, which along with our summer season, is one of our peak seasons of the year. Due to the mild weather, total generation for the quarter decreased 22% as compared to the first quarter of 2005.

Revenues

Revenues from our Northeast region totaled $392 million, including $223 million from energy revenues, for the three months ended March 31, 2006 compared to $332 million in total revenues and $276 million in energy revenues for the three months ended March 31, 2005. The decrease in energy revenues was due to lower generation from oil-fired assets, a decline of $77 million. Generation from the oil-fired assets decreased 90% as compared to the first quarter 2005 as an unseasonably mild weather lowered demand for generation from these peaking plants. Partially offsetting this decline was $18 million of settled hedges gain in energy revenues. These settled hedges had been recorded as financial revenue in 2005.

Capacity revenues for the three months ended March 31, 2006 were $58 million as compared to $65 million for the three months ended March 31, 2005. Capacity revenues were generally the same; however, last quarters results included a net $11 million in additional capacity revenues relating to our Connecticut RMR settlement agreement approved by FERC on January 22, 2005.

Other revenues include emission allowance revenues, natural gas sales, and expense recovery revenues. For the three months ended March 31, 2006, other revenues totaled $62 million as compared to $23 million of other revenues for the three months ended March 31, 2005. Other revenues were favorably impacted by $62 million of emission allowance sales to external and inter-company parties. Offsetting these sales was $22 million in lower gas sales. During the first quarter of 2005, we sold excess gas held in storage, resulting in the higher gas sales recognized under normal purchase and sale accounting. During 2006, we are actively trading gas and as such are recognizing the sales net of purchases.

Hedging and Risk Management Activity The total derivative gain for the period was $50 million, comprising of $1 million in financial revenue losses and $51 million of mark-to-market gains. The $1 million loss of financial revenue represents the settled value for the quarter of financial instruments that are not afforded hedge accounting treatment. Of the $51 million of mark-to-market gains, $31 million represents the change in fair value of forward sales of electricity and fuel, and $21 million represents the reversal of mark-to-market losses which ultimately settled as financial revenues. Additionally, we recognized a $1 million loss associated with our trading activity.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues (which are recorded net of financial instruments hedges that are afforded hedge accounting treatment) and costs of energy. Over the course of 2005, we hedged much of our calendar year 2006 Northeast generation. Since that time, the settled and forward prices of electricity decreased, resulting in the recognition of mark-to-market forward sales and the settlement of such positions as gains.

Cost of energy

Cost of energy decreased by $63 million for our Northeast region for the three months ended March 31, 2006 compared to the same period in 2005. Oil fuel costs in our Northeast region decreased by $51 million, where 115% of the decrease was due to lower generation from the oil-fired assets; offset by higher oil prices as compared to the first quarter of 2005. The Northeast s gas fuel costs decreased by $28 million, $2 million due to lower generation, $18 million due to generation demand and the balance of the decrease is related to gas purchases made in 2005 which were reported gross as they were recognized under normal purchase and sale accounting. During the first quarter of 2006, we began to actively optimize our gas capacity position, and as such, recognized those sales net of purchases. Despite a 40% decrease in generation from our New York City assets which reduced our gas fuel costs, gas fuel costs remained the same due to higher gas prices. Coal costs increased by $12 million, 55% due to higher volumes as total generation from our Northeast coal plants increased by 4% as compared to the first quarter of 2005.

Other Operating Expenses

Other operating expenses for our Northeast operations for the three months ended March 31, 2006 were $93 million or 24% of the Northeast s revenues, as compared to $95 million or 29% of revenues for the three months ended March 31, 2005. The decrease of operating expenses was due to $4 million in lower corporate allocations, as NRG Texas is now included in corporate cost allocations, reducing the allocation to the Northeast region. Major maintenance and other operating expenses were flat quarter over quarter.

South Central Region Results

Operating Income

For the quarter ended March 31, 2006, the South Central region realized operating income of $46 million, as compared to $12 million for the quarter ended March 31, 2005. This increase is due to higher generation of 10% over last year due to lower outage rates and increased sales to the merchant market. The EFORd rate improved to 1.2% for 2006 compared to an EFORd rate of 5.5% in 2005. Exceptional unit performance combined with local competitor outages created the opportunity for NRG to sell additional MWhs in the merchant market.

Revenues

Table of Contents

Revenues from our South Central region were $172 million for the quarter ended March 31, 2006, a $55 million increase from the first quarter in 2005. Energy revenues for the first quarter 2006 totaled $109 million, of which 43% were contracted. This compares to $69 million of energy revenues for the quarter ended March 31, 2005, of which 61% were contracted. This $40 million increase in energy revenues and the lower percentage of contracted revenues was due to increased merchant energy sales following higher power prices, improved unit performance and outages at competitor facilities. Tolling agreements, at times, provided power that could be resold at a higher price, boosting merchant revenues. Capacity revenues increased to $48 million during the first three months of 2006 compared to $45 million in the same three months of 2005. Emission allowance sales contributed $8 million during the first quarter 2006, of which $6.5 million were inter-company sales. There were no emission allowance sales during the same period of 2005. Other revenues include financial gas sales and contract amortization. For the quarter ended March 31, 2006, other revenues totaled $6 million compared to $0 million for the quarter ended March 31, 2005.

Cost of Energy

South Central s cost of energy increased by $23 million for the period ended March 31, 2006 compared to the same period in 2005. Of this amount, $22 million was due to increased purchased energy costs and the remaining $1 million was due to increased coal costs. The quantity of purchased MWh has nearly doubled to reach 526,200 MWh due to the tolling agreements and greater contract commitments. The average price of purchased energy increased from $16.83 to $66.20 per MWh for the quarter ended March 31, 2006 as compared to the same period in 2005.

Other Operating Expenses

Other operating expenses decreased by $3 million during the first quarter 2006 compared to the first quarter 2005. Normal maintenance decreased nearly $1 million compared to the same quarter in 2005 due to fewer forced outage hours. Lower bonus accruals led to $1 million in lower labor costs. Corporate allocations decreased $2 million in the first quarter 2006 compared to the first quarter 2005 as NRG Texas is now included in corporate cost allocations, reducing the allocation to the South Central region.

Western Region Results

For the period ending March 31, 2006, the Western region realized an operating loss of $2 million, as compared to operating loss of $1 million for the period ended March 31, 2005. This decrease is due to higher operating expenses at Red Bluff and Chowchilla facilities this year. These results do not include the equity earnings of Saguaro or West Coast Power.

Other North America Region Results

For the period ending March 31, 2006, the Other North America region realized an operating loss of $3 million and revenues of $1 million, as compared to an operating loss of $9 million and revenues of $1 million for the period ended March 31, 2005. This unfavorable variance was primarily related to the expiration of a contract at Rockford in May 2005. These results do not include the equity earnings of our Rocky Road investment.

Australia Region Results

Operating Income

For the quarter ended March 31, 2006, the Australia region realized operating income of $4 million, as compared to an operating loss of $3 million for the same period in 2005. Stronger pool prices and normal weather were offset by forced outages in the first quarter 2006. These mixed results were an improvement over the first quarter 2005 when unseasonably mild weather and soft pool prices led to weak quarterly performance.

Revenues

Revenues from our Australia region totaled $54 million for the quarter ended March 31, 2006 compared to $49 million for the quarter ended March 31, 2005. Energy revenues increased by $12 million due to an $11 per MWh increase in the average pool price. This was offset by an $8 million decrease in financial revenues, representing the settled value of financial instruments, including financial swaps on power, which were put in place to hedge NRG s contract obligations with Osborne.

Cost of Energy

Australia s cost of energy decreased by $4 million for the quarter ended March 31, 2006 compared to the same period in 2005. Of this amount $3 million was due to lower purchased energy costs as a result of lower purchased power obligations from Osborne due to transformer outage in January and the inability of the plant to deliver contracted power during this outage.

Other Operating Expenses

During the first quarter 2006, other operating expenses increased by $3 million compared to the same quarter in 2005. Normal and major maintenance increased by $2 million during the first quarter of 2006 as a result of unplanned outages and mine equipment repair costs as well as preparatory spending for a planned outage at the Northern Power Station. Regular and contract labor expense increased by $1 million for the period due to an increase in pension accruals. Offsetting these increases was a decrease of $0.5 million in corporate allocations from the period ended March 31, 2005 to the period ended March 31, 2006.

Known Trends and Other Factors Affecting our Results of Operations

Acquisition of NRG Texas and the remaining 50% interest in WCP

Because Texas Genco LLC was acquired on February 2, 2006, NRG s consolidated results do not include NRG Texas s operating results from January 1, 2006 through February 1, 2006. Also, on March 31, 2006, NRG acquired the remaining 50% interest in WCP from Dynegy, Inc. Our consolidated operating results for the three months ended March 31, 2006, do not include the operating results of WCP, however, our net income includes our 50% equity earnings from WCP.

Please see the supplemental pro forma information in Note 4 *Business Combination,* to our condensed consolidating financial statements for the potential impact to our consolidating results based on the historical results of NRG Texas and WCP.

Australia

We are currently considering strategic alternatives with respect to our investments in Australia either to reposition our assets more effectively within the National Electricity Market or to monetize our investments. As part of this process, we have received non-binding indicative bids and the bidders are conducting detailed due diligence. We will continue to assess these bids and other options to optimize our investment. We expect to finalize our strategy and begin its execution by the end of the second quarter of 2006.

If we sell our Australia investments, our future operating results will be negatively affected. For the three months ended March 31, 2006, revenue, operating income and net income attributable to our Australia segment were $54 million, $4 million and $5 million, respectively.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. 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 impact 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, we evaluate our estimates, utilizing historic experience, consultation with experts and other methods we consider reasonable. In any case, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Goodwill and Other Intangible Assets

As part of the acquisition of Texas Genco LLC we have recorded intangible assets and goodwill. We are applying SFAS 141, and SFAS 142 *Goodwill and Other Intangible Assets*, to account for these intangibles. Under these standards we are amortizing all finite-lived intangible assets over their respective estimated weighted-average useful life, whereas goodwill has an indefinite life and is not amortized. However, goodwill and all intangible assets will be tested for impairment whenever an event occurs that indicates that an impairment may have occurred, or at a minimum on an annual basis. If necessary, our goodwill and/or intangible asset will be impaired at that time.

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

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

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

Currently, we have valued goodwill on a preliminary basis at approximately $2.7 billion. Our preliminary appraisal of Property, Plant and Equipment increased its fair value, as compared to Texas Genco LLC s historical cost, by approximately $4.6 billion. If the remaining goodwill balance is indicative of a further increase in value of depreciable property plant and equipment, depreciation expense for the period ended March 31, 2006, would increase by approximately $25 million, reducing income from continuing operations before tax to a loss of approximately $7 million.

Liquidity and Capital Resources

Significant Events during the three months ended March 31, 2006

- The acquisition of Texas Genco LLC
- The issuance of $5.6 billion in a new credit facility, including a $1 billion revolving credit facility and $1 billion synthetic letter of credit facility; $3.6 billion in unsecured high yield notes; $500 million of 5.75% Preferred Stock; and $1 billion of common stock
- The termination of our term loan, funded letter of credit and revolving credit facilities issued on December 24, 2004
- The repurchase of $1.1 billion in aggregate principal amount of our 8% Second Priority Notes
- The repurchase of $1.1 billion in aggregate principal amount of NRG Texas s and Texas Genco Financing Corp. s 6.875% senior notes
- The return of cash collateral payments of $230 million due to the downward shift in the underlying price curves
- Sale of non-core assets resulting in $60 million in proceeds
- The purchase of 50% of the interest in WCP and sale of our 50% interest in Rocky Road for a net $160 million

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

The acquisition of Texas Genco LLC was partially funded at closing with the combination of (i) cash proceeds received upon the issuance and sale in a public offering of 20,855,057 shares of our common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $1.2 billion aggregate principal amount of

7.25% Senior Notes due 2014 and $2.4 billion aggregate principal amount of 7.375% Senior Notes due 2016; (iii) cash proceeds received upon the issuance and sale in a public offering of 2 million shares of mandatory convertible preferred stock at a price of $250 per share; (iv) funds borrowed under a new senior secured credit facility consisting of a $3.575 billion term loan facility, a $1.0 billion revolving credit facility and a $1.0 billion synthetic letter of credit facility; and (v) cash on hand.

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

The purchase price for the 8% Second Priority Notes totaling approximately $1.2 billion was paid by NRG on February 2, 2006 and the purchase price for the Texas Genco Notes totaling approximately $1.2 billion was paid by NRG on February 3, 2006, with proceeds from the issuance of new unsecured high yield notes.

As of March 31, 2006, we had $3.6 billion in aggregate principal amount of unsecured high yield notes, or Senior Notes, and $3.575 billion in principal amount outstanding under the term loan. We have issued $798 million of letters of credit under our $1 billion funded letter of credit facility, leaving $202 million available for future issuances. Under our $1 billion revolving facility, we have issued $154 million in letters of credit, leaving $146 available for future issuances of letters of credit or $846 million available for borrowings. As of May 3, 2006, $186 million of undrawn letters of credit remain available under the funded letter of credit facility, $146 million of undrawn letters of credit remain available under the revolving credit facility, and we had no borrowings on our revolving credit facility.

On March 15, 2006, we paid a total of approximately $10 million in dividends to the holders of our 3.625% Preferred Stock, 4% Preferred Stock, and 5.75% Preferred Stock.

In connection with our power generation business, we manage the commodity price risk associated with our supply activities and our electric generation facilities. This includes forward power sales, fuel and energy purchases and emission credits. In order to manage these risks, we enter into financial instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy. We utilize a variety of instruments including forward contracts, future contracts, swaps and options.

Certain of these contracts allow counterparties to require NRG to post margin collateral. As of May 3, 2006, we have posted $229 million in collateral to support these contracts.

In March 2004, we entered into two interest rate swap agreements, one of which matured on March 31, 2006. The remaining swap agreement matures in 2011. Depending on market interest rates, we or the swap counterparty may be required to post collateral on a daily basis in support of this swap, to the benefit of the other party. On March 31, 2006 and May 3, 2006, we had posted $17 million and $24 million in collateral.

Sale or Purchase of Assets

On March 29, 2006, we completed the sale of the Audrain Generating Station to AmerenUE, a subsidiary of Ameren Corporation. The purchase price was $115 million, subject to purchase price adjustments, plus Ameren s assumption of $240 million of non-recourse capital lease obligations and our assignment of a $240 million note receivable. Of the $115 million in cash proceeds, approximately $20 million was paid to NRG, and the balance was paid to the lenders under a pre-chapter 11 credit facility.

On March 31, 2006, we acquired the remaining 50% ownership interest in WCP and completed the sale of our 50% ownership interest in Rocky Road Power LLC to Dynegy Inc. We paid Dynegy $205 million for its interest in WCP and received $45 million from Dynegy for our interest in Rocky Road.

Capital Expenditures

Capital expenditures were approximately $35 million and $11 million for the three months ended March 31, 2006 and March 31, 2005, respectively. We anticipate that our 2006 capital expenditures will be approximately $280 million and will relate to the operation and maintenance of our existing generating facilities. Our capital expenditures will be funded through cash from operations.

Liquidity

As of March 31, 2006, our liquidity was $1,933 million and includes $885 million of unrestricted and restricted cash. Our liquidity also includes $846 million of borrowing capacity under our revolving line of credit, and $202 million of availability under our letter of credit facility. As of December 31, 2005, our liquidity was $758 million and included $570 million of cash and restricted cash. Our liquidity also included $150 million of available capacity under our revolving line of credit and $38 million of availability under our letter of credit facility.

Other Liquidity Matters NOL s and Deferred Tax Assets

As of March 31, 2006, we have a U.S. domestic net operating loss carryforward of $290 million which will expire through 2026. We believe that it is more likely than not that a benefit will not be realized on the deferred tax assets relating to the net operating loss carryforwards. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of March 31, 2006, a valuation allowance of $1,243 million was recorded against the net deferred tax assets. These deferred tax assets are primarily comprised of amounts created at the acquisition of Texas Genco LLC and net operating loss carryforwards in accordance with FAS 109.

Cash Flows

We have obtained cash from operations, proceeds from repayment of outstanding notes receivable, proceeds from the sale of certain assets, proceeds from the sale of common and preferred stock, and proceeds from the issuance of long-term debt. We have used these funds to acquire businesses, finance operations, service project-level debt obligations, finance capital expenditures, and meet other cash and liquidity needs. In conjunction with our acquisition of NRG Texas, we also redeemed our existing Second Priority Notes, terminated our existing Amended Credit Facility, and redeemed NRG Texas s Senior Notes and Term Loan.

The following table reflects the changes in cash flows for the comparative years and we include a detailed discussion on the changes during the last year. All cash flow categories include the cash flows from continuing operations and discontinued operations:

	For the Three Months Ended March 31, 2006	March 31, 2005
	(In millions)	
Net cash provided by operating activities	$ 366	$ 64
Net cash provided/(used) by investing activities	(4,255)	92
Net cash provided/(used) in financing activities	4,200	(501)

Net Cash Provided By Operating Activities

For the quarter ended March 31, 2006, net cash provided by operating activities increased by $302 million compared to the quarter ended March 31, 2005. This was primarily due to the following reasons:

Due to expiration of the underlying contracts and the downward shift of the forward price curves, our collateral deposits in support of derivative contract terms decreased by $230 million during the quarter ended March 31, 2006, compared to an increase of $136 million during the quarter ended March 31, 2005, a difference of $366 million. As of March 31, 2006 we had collateral deposits of $251 million;

Due to the redemption of our previous senior notes, a premium of $126 million was paid to our former debt holders;

Unrealized gains on derivatives decreased by $50 million during the quarter ended March 31, 2006, compared to an increase of $85 million in unrealized losses during the quarter ended March 31, 2005, a difference of $135 million; and

Due to redemption of our Second Priority Secured Notes, during the quarter ended March 31, 2006 we wrote off $61 million of deferred financing costs less debt discounts of $14 million for a net write-off of $47 million, compared to a write-off of debt premiums of $8 million during the quarter ended March 31, 2005, a difference of $55 million.

Net Cash Provided By/(Used in)Investing Activities

For the quarter ended March 31, 2006, net cash used in investing activities was approximately $4.3 billion more than for the quarter ended March 31, 2005. This increase was due to the following mix of investment activities:

During the quarter ended March 31, 2006, we acquired Texas Genco LLC for approximately $6.2 billion (net of assumed debt), which included the issuance of stock at a value of $1.7 billion and net cash payment of approximately $4.3 billion;

We acquired Dynegy s 50% ownership interest in WCP for $25 million (net of cash on hand at WCP hand of $180 million). Prior to the purchase, NRG had an existing investment in WCP accounted for as an unconsolidated equity method investment;

We sold to Dynegy our 50% ownership interest in Rocky Road for $45 million;

Our capital expenditures were $24 million more during the quarter ended March 31, 2006 as compared to the quarter ended March 31, 2005 with the increase primarily related to the capital expenditures at NRG Texas; and

In comparison to a decrease of $35 million during the quarter ended March 31, 2005, restricted cash balances increased by $3 million, a decrease of $32 million. This decrease is due to the first quarter 2005 Flinder s debt refinancing, which released approximately $38 million of restricted cash.

Net Cash Provided By/(Used in) Financing Activities

For the quarter ended March 31, 2006, net cash provided by financing activities increased by approximately $4.7 billion in comparison to the quarter ended March 31, 2005. The increase was due primarily to the financing activities surrounding our purchase of Texas Genco LLC, and consisted of the following:

In conjunction with the purchase of NRG Texas we refinanced our outstanding debt as well as NRG Texas s outstanding debt as we:

- Repaid $446 million in outstanding principal and terminated our term loan under our Amended Credit Facility;
- Repurchased and retired approximately $1.1 billion of our Second Priority Notes, pursuant to a tender offer; and
- Repurchased NRG Texas s outstanding notes for approximately $1.1 billion and NRG Texas s term loan for approximately $500 million.

As part of raising the funds to purchase NRG Texas and to refinance the combined NRG debt portfolio, we:

- Issued 20,855,057 shares of common stock on January 31, 2006 at an offering price of $48.75 per share for total net proceeds of approximately $985 million, after deducting expenses;
- Issued 2 million shares of 5.75% Preferred Stock on January 30, 2006 at an offering price of $250 per share for total net proceeds of approximately $486 million, after deducting expenses;

- o Entered into a new senior secured credit facility providing for up to an aggregate amount of $5.575 billion, consisting of a $3.575 billion Term Loan Facility, a $1.0 billion Revolving Credit Facility and a $1.0 billion Letter of Credit Facility; and

- o Issued (i) $1.2 billion aggregate principal amount of 7.25% Senior Notes, and (ii) $2.4 billion aggregate principal amount of 7.375% Senior Notes.

Known Trends and Other Factors Affecting our Liquidity

Capital Allocation

The Company s stated capital allocation program includes business reinvestment, management of debt levels, and the return of capital to shareholders. The allocation of capital to any of these areas could have a material affect on our future liquidity. Further definition of our allocation program is provided below.

Business Reinvestment Opportunities to invest into the existing business, pursue brownfield development and expansion projects, or other investments in the existing assets that are intended to provide an economic return to the Company through increased cash flow or the improved reliability of operations

Management of Debt Levels The Company uses several metrics to measure the efficiency of its capital structure and debt balances. Generally, the Company s targeted net debt to total capital ratio range is 45% to 60%. The Company intends to continue to manage its debt levels towards the lower end of the range and may, from time to time, pay debt balances down to manage to within this targeted range.

Return of Capital to Shareholders While the Company s debt indentures include restrictions on the amount of capital that can be returned to shareholders, the Company has in the past returned capital to shareholders while maintaining compliance with existing debt agreements and indentures. The Company will consider future opportunities to the extent they may exist.

Australia

We are currently considering strategic alternatives with respect to our investments in Australia either to reposition our assets more effectively within the National Electricity Market or to monetize our investments. As part of this process, we have received non-binding indicative bids and the bidders are conducting detailed due diligence. We will continue to assess these bids and other options to optimize our investment. We expect to finalize our strategy and begin its execution by the end of the second quarter of 2006.

Off-Balance Sheet Arrangements

Obligations Under Certain Guarantee Contracts

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

Retained or Contingent Interests

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

Derivative Instrument obligations

On August 11, 2005 NRG issued the 3.625% Preferred Stock that includes a conversion feature which was considered a derivative per FAS 133. Although it is considered a derivative, it was exempt from derivative accounting as it was excluded from the scope pursuant to paragraph 11(a) of FAS 133. Despite this exclusion, per the guidance of EITF Topic D-98 the conversion feature must be marked-to-market. Currently, the conversion feature is valued at $0 as our stock price is outside the conversion range.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Table of Contents

Variable interest in Equity investments As of December 31, 2005, we have 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 us. However, we have numerous 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. Our pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $181 million and $178 million as of March 31, 2006 and December 31, 2005, respectively. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to us. In the normal course of business we may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates.

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

As of March 31, 2006, we had issued $798 million in funded letters of credit under the Letter of Credit Facility. Of this amount, a portion was issued to support obligations under terminated NRG letter of credit facilities. As of March 31, 2006, we had issued $154 million in revolver letters of credit, a portion of which supports non-commercial letter of credit obligations under letters of credit facilities terminated as of February 2, 2006.

Contractual Obligations and Commercial Commitments

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

See Note 15, *Commitments and Contingencies*, to the condensed consolidated financial statements for a discussion of commitments and contingencies that also include contractual obligations and commercial commitments that occurred during 2006.

Derivative Instruments

We may enter into forward power sales contracts, forward gas purchase contracts and other financial energy commodity instruments to mitigate variability in earnings due to fluctuations in spot market prices, to hedge fuel requirements at generation facilities and to protect fuel inventories. In addition, in order to mitigate interest rate risk associated with the issuance of our variable rate and fixed rate debt, we enter into interest rate swap agreements.

The tables below disclose the derivative contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at March 31, 2006 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at March 31, 2006.

Derivative Activity Gains/(Losses)

	(In millions)
Fair value of contracts at December 31, 2005	$ (403)
Contracts realized or otherwise settled during the period	55
Value of contracts acquired with NRG Texas on February 2, 2006	(472)
Changes in fair value	272
Fair value of contracts at March 31, 2006	$ (548)

Sources of Fair Value Gains/(Losses)

Table of Contents

	Fair Value of Contracts at Period End as of March 31, 2006				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
			(In millions)		
Prices actively Quoted	$ (216)	$ (119)	$ (140)	$	$ (475)
Prices provided by other external sources	(7)	8	31	(33)	(1)
Prices based on models and other valuation methods	1	(28)	(9)	(36)	(72)
Total	$ (222)	$ (139)	$ (118)	$ (69)	$ (548)

We may use a variety of financial instruments to manage our exposure to interest rates on our cost of borrowing, energy and energy related commodities prices and fluctuations in foreign currency exchange rates on our international project cash flows.

Table of Contents

Item 3 Quantitative and Qualitative Disclosures About Market Risk

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with our merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to include commodity price risk, interest rate risk and currency exchange risk. In order to manage these risks we enter into various financial instruments including 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 our fixed-price purchase and sales commitments;

Manage and hedge our exposure to variable rate debt obligations;

Reduce our exposure to the volatility of market prices; and

Hedge our fuel requirements for our generating facilities.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities 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;

Changes in the nature and extent of federal and state regulations; and

Political uncertainty in oil producing regions.

As part of our overall portfolio, we manage the commodity price risk of our generation assets 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. The portion of forecasted transactions hedged may vary based upon management s assessment of market, weather, operational, and other factors.

While some of the contracts we use 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. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuations, and such variations could be material.

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

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

This model encompasses the following generating regions: ENTERGY, NEPOOL, NYPP, PJM, WSCC and MAIN. The estimated maximum potential loss in fair value of our commodity portfolio, including generation assets, load obligations and bilateral physical and financial transaction, calculated using the diversified VAR model is as follows:

		(In millions)
As of March 31, 2006	$	29.6
Average for the three months ended March 31, 2006		32.7
High		38.0
Low		26.8
As of December 31, 2005		36.9
Average for the year ended December 31, 2005		27.6
High		45.9
Low		16.0

In order to provide additional information for comparative purposes to our peers we also utilize value at risk to model the estimate of potential loss of financial derivative instruments included in derivative instruments valuation assets and liabilities. This estimation includes those energy contracts accounted for as a hedge under SFAS 133, as amended. The estimated maximum potential loss in fair value of the financial derivative instruments calculated using the diversified VAR model as of March 31, 2006 is approximately $23 million.

The NRG Texas portfolio, which has not been fully integrated with the rest of NRG, has a standalone estimated maximum potential loss in fair value including generation assets, load obligations and bilateral physical and financial transaction, calculated as of March 22, 2006 using the diversified VAR model of approximately $36.7 million. We expect to completely integrate the two portfolios and begin reporting VAR measures for the combined portfolio by the end of the second quarter of 2006.

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

Interest Rate Risk

We are exposed to fluctuations in interest rates through our 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. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

In January 2006, we 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, we pay our counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we receive quarterly the equivalent of a floating interest payment based on 3-month LIBOR rate calculated on the same notional value. All payments by us and our counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of May 3, 2006 was $2.15 billion. The notional amounts and maturities of each tranche of these swaps are described in Note 8 *Long Term Debt and Capital Leases* to the condensed consolidated financial statements.

As of March 31, 2006, we and our consolidated subsidiaries had various interest rate swap agreements with notional amounts totaling approximately $3.0 billion. If the swaps had been discontinued on March 31, 2006, we would have owed the counter-parties approximately $1 million. Based on the investment grade rating of the counterparties, we believe that our exposure to credit risk due to nonperformance by the counterparties to our hedging contracts is insignificant.

We have both long and short-term debt instruments that subject us to the risk of loss associated with movements in market interest rates. As of March 31, 2006, a 100 basis point change in interest rates would result in a $19 million change in interest expense on a rolling 12 month basis.

At March 31, 2006, the fair value and the carrying value of our fixed-rate long-term debt was $8 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our fixed-rate long-term debt by approximately $443 million.

Liquidity Risk

Our collateral posted in support of our management of our electric generation facilities fluctuates based on the amount of the portfolio hedged using collateralized contracts and market price movements. Based on a sensitivity analysis a $1 per MWh increase or decrease in electricity prices would cause a change in margin collateral outstanding of approximately $14 million. This sensitivity uses simplified assumptions and may not reflect actual market movements.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. We monitor and manage the credit risk of NRG and its subsidiaries through credit policies which include an (i) established credit approval process, (ii) daily monitoring of counter-party credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements, and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We have credit protection within various agreements to call on additional collateral support if necessary. As of March 31, 2006, we held collateral support of approximately $405 million from counterparties.

A portion of our credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities as of March 31, 2006:

	Exposure Before Collateral	Collateral	Net Exposure
		(In millions)	
Investment grade	$ 566	$ 218	$ 348
Non-investment grade	49	40	9
Not rated	145	39	106
Total	$ 760	$ 297	$ 463
Investment grade	75%	73%	75%
Non-investment grade	6%	14%	2%
Not rated	19%	13%	23%

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

NRG s exposure to significant counterparties greater than 10% of the net exposure of approximately $463 million was approximately $350 million as of March 31, 2006. We do not anticipate any material adverse effect on our financial position or results of operations as a result of nonperformance by any of our counterparties.

Currency Exchange Risk

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

As of March 31, 2006, neither we, nor any of our consolidating subsidiaries, had any material outstanding foreign currency exchange contracts.

Table of Contents

Item 4 Controls and Procedures

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

Except for the completion of the acquisition of Texas Genco LLC and WCP, and the commencement of the associated integration of these entities, there have been no changes in the Company s internal control over financial reporting during the completed first quarter that have materially affected, or are reasonably likely to materially affect the Company s internal control over financial reporting. We previously owned a 50% equity interest in WCP and acquired the remaining interest in WCP with this acquisition.

Table of Contents

PART II OTHER INFORMATION

Item 1 Legal Proceedings

For a discussion of material legal proceedings in which we were involved through March 31, 2006, see Note 15 *Commitments and Contingencies* to our condensed consolidated financial statements contained in Part I, Item 1 of this Form 10-Q.

Item 1A Risk Factors

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

Item 2 Unregistered Sales of Equity Securities and Use of Proceeds

On February 2, 2006, NRG acquired Texas Genco LLC, a Delaware limited liability company, by purchasing all of the outstanding equity interests in Texas Genco LLC pursuant to the Acquisition Agreement, dated September 30, 2005, by and among NRG, Texas Genco LLC, and each of the direct and indirect owners of Texas Genco LLC, or the Sellers. A portion of the consideration paid to the Sellers consisted of 35,406,292 shares of our common stock to the Sellers in a private placement in reliance on Section 4(2) of the Securities Act of 1933, as amended.

Item 3 Defaults Upon Senior Securities

None.

Item 4 Submission of Matters to a Vote of Security Holders

None.

Item 5 Other Information

None.

Item 6 Exhibits

Exhibits

10.1*	Chief Executive Officer Compensation Table for 2006, filed by the Company as an exhibit to the Form 8-K filed on January 5, 2006, and incorporated herein by reference.
10.2	Credit Agreement, dated February 2, 2006, among NRG, the lenders party thereto, Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc., as joint lead book runners, joint lead arrangers and co-documentation agents, Morgan Stanley&Co. Incorporated, as collateral agent, and Citigroup Global Markets Inc., as syndication agent, filed by the Company as an exhibit to the Form 8-K filed on February 6, 2006, and incorporated herein by reference.
10.3	Investor Rights Agreement, dated as of February 2, 2006, by and among NRG Energy, Inc. and Certain Stockholders of NRG Energy, Inc. set forth therein, filed by the Company as an exhibit to the Form 8-K filed on February 8, 2006, and incorporated herein by reference.
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.

* Exhibit relates to compensation arrangements.

Table of Contents

SIGNATURES

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

NRG ENERGY, INC.
(Registrant)

/s/ DAVID CRANE

David Crane,
Chief Executive Officer

/s/ ROBERT C. FLEXON

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

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby,
Controller
(Principal Accounting Officer)

Date: May 9, 2006

66

Table of Contents

EXHIBIT INDEX

Exhibits

10.1*	Chief Executive Officer Compensation Table for 2006, filed by the Company as an exhibit to the Form 8-K filed on January 5, 2006, and incorporated herein by reference.
10.2	Credit Agreement, dated February 2, 2006, among NRG, the lenders party thereto, Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc., as joint lead book runners, joint lead arrangers and co-documentation agents, Morgan Stanley&Co. Incorporated, as collateral agent, and Citigroup Global Markets Inc., as syndication agent, filed by the Company as an exhibit to the Form 8-K filed on February 6, 2006, and incorporated herein by reference.
10.3	Investor Rights Agreement, dated as of February 2, 2006, by and among NRG Energy, Inc. and Certain Stockholders of NRG Energy, Inc. set forth therein, filed by the Company as an exhibit to the Form 8-K filed on February 8, 2006, and incorporated herein by reference.
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.

* Exhibit relates to compensation arrangements.