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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year ended December 31, 2006.

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from to .

Commission file No. 001-15891

NRG Energy, Inc.

(Exact name of Registrant as specified in its charter)

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, par value $0.01	New York Stock Exchange
5.75% Mandatory Convertible Preferred Stock	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☑

Indicate by check mark whether the Registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $6,599,652,171 based on the closing sale price of $48.18 as reported on the New York Stock Exchange.

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 Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date.

Class	Outstanding at February 23, 2007
Common Stock, par value $0.01 per share	122,335,466

Documents Incorporated by Reference:

Portions of the Proxy Statement for the 2007 Annual Meeting of Stockholders to be held on April 25, 2007

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Glossary of Terms

Glossary of Terms — (continued)

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

ABWR	Advanced Boiling Water Reactor
Acquisition	February 2, 2006 acquisition of Texas Genco LLC, now referred to as the Company's Texas region
Acquisition Agreement	Acquisition Agreement dated September 30, 2005 underlying the February 2, 2006 acquisition of the Company's Texas region
AMA	Administrative Management Agreement between NRG Development Company, Inc. and West Coast Power, LLC
APB	Accounting Principles Board
APB 18	APB Opinion No. 18, *"The Equity Method of Accounting for Investments in Common Stock"*
Average gross heat rate	The product of dividing (a) fuel consumed in BTU's by (b) KWh generated
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Baseload capacity	Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
BTA	Best Technology Available
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
Capacity factor	The ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year
Capital Allocation Program	Share repurchase program entered into August 2006
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
Derate	A derate exists whenever a generating unit is not capable of operating at its tested dependable maximum net capability
DNREC	Delaware Department of Natural Resources and Environmental Control
EAF	The total available hours a unit is available in a year minus the sum of all partial outage events in a year converted to equivalent hours, expressed as a percent of all hours in the year
EFOR	Equivalent Forced Outage Rates — considers the equivalent impact that forced de-ratings have in addition to full forced outages
EITF	Emerging Issues Task Force
EITF 02-3	EITF 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"*
EPAct of 2005	Energy Policy Act of 2005
EPC	Engineering, Procurement and Construction

ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ERO	Energy Reliability Organization
EWG	Exempt Wholesale Generator
Expected annual baseload generation	The net baseload capacity limited by economic factors (relationship between cost of generation and market price) and reliability factors (scheduled and unplanned outages)
FASB	Financial Accounting Standards Board, the designated organization for establishing standards for financial accounting and reporting
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
FIN	FASB Interpretation
FIN 45	FIN No. 45 *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"*
FIP	Federal Implementation Plan
Fresh Start	Reporting requirements as defined by SOP 90-7
GHG	Greenhouse Gases
Hedge Reset	Net settlement of long-term power contracts and gas swaps by negotiating prices to current market completed in November 2006
Hg	Mercury
ICT	Independent Coordinator of Transmission
IGCC	Integrated Gasification Combined Cycle
IRS	Internal Revenue Service
ISO	Independent System Operator, also referred to as Regional Transmission Organizations, or RTO
ISO-NE	ISO New England, Inc.
ITISA	Itiquira Energetica S.A.
kW	Kilowatts
KWh	Kilowatt-hours
LADEQ	Louisiana Department of Environmental Quality
LFRM	Locational Factor Reserve Market
LIBOR	London Inter-Bank Offered Rate
LNB/OFA	Low NOx Burner with Over Fire Air
LSE	Load-Serving Entity
MACT	Maximum Achievable Control Technology
MADEP	Massachusetts Department of Environmental Protection
MDL	Multi-District Litigation
Merit Order	A term used for the ranking of power stations in terms of increasing order of fuel costs
MIBRAG	Mitteldeutsche Braunkohlengesellschaft mbH
Moody's	Moody's Investors Services, Inc., a credit rating agency
MMBtu	Million British Thermal Units
MRTU	Market Redesign and Technology Upgrade
MW	Megawatts

MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NAAQS	National Ambient Air Quality Standards
Net baseload capacity	Nominal summer net megawatt capacity of power generation adjusted for ownership and parasitic load, and excluding capacity from mothballed units as of December 31, 2006
Net Capacity Factor	Net actual generation divided by net maximum capacity for the period hours
Net Generating Capacity	Nominal summer capacity, net of auxiliary power
New York Rest of State	New York State excluding New York City
NiMo	Niagara Mohawk Power Corporation
NOx	Nitrogen oxide
NOL	Net Operating Loss
NOV	Notice of Violation
NRC	United States Nuclear Regulatory Commission
NSR	New Source Review
NYPA	New York Power Authority
NYISO	New York Independent System Operator
NYSDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
OTC	Ozone Transport Commission
Phase II 316(b) Rule	A section of the Clean Water Act regulating cooling water intake structures
PJM	PJM Interconnection, LLC
PJM Market	The wholesale and retail electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia
PM (2.5)	Fine particulate matter
PMI	NRG Power Marketing, Inc., a wholly-owned subsidiary of NRG which procures transportation and fuel for the Company's generation facilities, sells the power from these facilities, and manage, all commodity trading and hedging for NRG
Powder River Basin, or PRB, Coal	Coal produced in the northeastern Wyoming and southeastern Montana, which has low sulfur content
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policy Act of 2005
RCRA	Resource Conservation and Recovery Act
RECLAIM	Regional Clean Air Incentives Market
Repowering NRG	Technologies utilized to replace, rebuild, or redevelop major portions of an existing electrical generating facility, not only to achieve a substantial emissions reduction, but also to increase facility capacity, and improve system efficiency
RFP	Request for proposal
RGGI	Regional Greenhouse Gas Initiative

RMR	Reliability Must-Run
ROIC	Return on invested capital
RTC	RECLAIM Trading Credit
RTO	Regional Transmission Organization, also referred to as an ISO
S&P	Standard & Poor's, a credit rating agency
SARA	Superfund Amendments and Reauthorization Act of 1986
Sarbanes-Oxley	Sarbanes — Oxley Act of 2002
SCAQMD	South Coast Air Quality Management District
Schkopau	Kraftwerk Schkopau Betriebsgesellschaft mbH, an entity in which NRG has a 41.9% interest
SCR	Selective Catalytic Reduction
SDG&E	San Diego Gas & Electric
SEC	United States Securities and Exchange Commission
Sellers	Former holders of Texas Genco LLC shares
SERC	Southeastern Electric Reliability Council/Entergy
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS 71	SFAS No. 71 *"Accounting for the Effects of Certain Types of Regulation"*
SFAS 87	SFAS No. 87, *"Employers' Accounting for Pensions"*
SFAS 106	SFAS No. 106, *"Employers' Accounting for Postretirement Benefits Other Than Pensions"*
SFAS 109	SFAS No. 109, *"Accounting for Income Taxes"*
SFAS 123	SFAS No. 123, *"Accounting for Stock-Based Compensation"*
SFAS 123R	SFAS No. 123 (revised 2004), *"Share-Based Payment"*
SFAS 133	SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"*
SFAS 137	SFAS No. 137, *"Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of FASB Statement No. 133"*
SFAS 138	SFAS No. 138, *"Accounting for Certain Derivative Instruments and Certain Hedging Activities — an amendment of FASB Statement No. 133"*
SFAS 142	SFAS No. 142, *"Goodwill and Other Intangible Assets"*
SFAS 143	SFAS No. 143, *"Accounting for Asset Retirement Obligations"*
SFAS 144	SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"*
SFAS 149	SFAS No. 149, *"Amendment of Statement 133 on Derivative Instruments and Hedging Activities"*
SFAS 158	SFAS No. 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106 and 132(R)"*
SFAS 159	SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment of FASB Statement No. 115"*
SNCR	Selective non-catalytic reduction
SIP	State Implementation Plan
SO_2	Sulfur dioxide

SOP	Statement of Position issued by the American Institute of Certified Public Accountants
SOP 90-7	Statement of Position 90-7 *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*
SPP	Southwest Power Pool
STP	South Texas Project — Nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest
STPNOC	South Texas Project Nuclear Operating Company
TCEQ	Texas Commission on Environmental Quality
Texas Genco	Texas Genco LLC, now referred to as the Company's Texas region
Uprate	A sustainable increase in the electrical rating of a generating facility
US	United States of America
USEPA	United States Environmental Protection Agency
U.S. GAAP	Accounting principles generally accepted in the United States
VAR	Value at Risk
Virtual Units	Products sold with scheduling characteristics for energy and ancillary services that are based on an underlying unit physical characteristic
VOC	Volatile Organic Carbon
WCP	WCP (Generation) Holdings, Inc.

PART I

Item 1 — *Business*

General

NRG Energy, Inc., NRG, or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is primarily engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and internationally. As of December 31, 2006, NRG had a total global portfolio of 223 active operating generation units at 51 power generation plants, with an aggregate generation capacity of approximately 24,175 MW. Within the United States, the Company has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,940 MW of generation capacity in 207 active generating units at 45 plants. These power generation facilities are primarily located in Texas (approximately 10,760 MW), and the Northeast (approximately 7,240 MW), South Central (approximately 2,850 MW), and the West (approximately 1,965 MW) regions of the United States, with approximately 125 MW from the Company's thermal assets. NRG's principal domestic power plants consist of a diversified mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 45%, 34%, 16% and 5% of the Company's total domestic generation capacity, respectively. In addition, 15% of NRG's domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option, and consist primarily of baseload, intermediate and peaking power generation facilities, which are referred to as the merit order, and also include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company's revenues and provides a stable source of cash flow. In addition, NRG's diverse generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability. In addition, NRG is pursuing opportunities to repower existing facilities and develop new generation capacity in markets in which NRG currently owns assets in an initiative referred to as *Repowering NRG.* In connection with NRG's acquisition of Padoma Wind Power LLC, the Company has and will continue to actively evaluate and potentially develop or construct domestic terrestrial wind projects as part of the *Repowering NRG* program.

Business Strategy

NRG's strategy is to optimize the value of the Company's generation assets while using its asset base as a platform for growth and enhanced financial performance which can be sustained and expanded upon in the years to come. NRG plans to maintain and enhance the Company's position as a leading wholesale power generation company in the United States in a cost-effective and risk-mitigating manner in order to serve the bulk power requirements of NRG's existing customer base and other entities that offer load or otherwise consume wholesale electricity products and services in bulk. NRG's strategy includes the following elements:

Pursue additional growth opportunities at existing sites — NRG is favorably positioned to pursue growth opportunities through expansion of its existing generating capacity and development of new generating capacity at its existing facilities. NRG intends to invest in its existing assets through plant improvements, repowerings, brownfield development and site expansions to meet anticipated requirements for additional capacity in NRG's core markets. In furtherance of this goal, NRG has initiated a company-wide program, known as *Repowering NRG*, to develop, construct and operate new and enhanced power generation facilities at its existing sites, with an emphasis on new baseload capacity that is supported by long-term power sales agreements and financed with limited or non-recourse project financing. NRG expects that these efforts will provide one or more of the following benefits: improved heat rates; lower delivered costs; expanded electricity production capability; an improved ability to dispatch economically across the merit order; increased technological and fuel diversity; and reduced environmental impacts, including facilities that either have near zero greenhouse gas emissions or can be equipped to capture and sequester greenhouse gas emissions.

Increase value from existing assets — NRG has a highly diversified portfolio of power generation assets in terms of region, fuel-type and dispatch levels. NRG will continue to focus on extracting value from its portfolio by improving plant performance, reducing costs and harnessing the Company's advantages of scale in the procurement of fuels and other commodities, parts and services, and in doing so improve the Company's return on invested capital, or ROIC — a strategy that NRG has branded *FORNRG,* or Focus on ROIC@NRG.

Maintain financial strength and flexibility — NRG remains focused on cash flow and maintaining appropriate levels of liquidity, debt and equity in order to ensure continued access to capital for investment, to enhance risk-adjusted returns and to provide flexibility in executing NRG's business strategy. NRG will continue to focus on maintaining operational and financial controls designed to ensure that the Company's financial position remains strong. At the same time, NRG expects to continue its practice of returning excess cash flows to its debt and equity investors on a regular basis.

Reduce the volatility of the Company's cash flows through asset-based commodity hedging activities — NRG will continue to execute asset-based risk management, hedging, marketing and trading strategies within well defined risk and liquidity guidelines in order to manage the value of the Company's physical and contractual assets. The Company's marketing and hedging philosophy is centered on generating stable returns from its portfolio of baseload power generation assets while preserving an ability to capitalize on strong spot market conditions and to capture the extrinsic value of the Company's intermediate and peaking facilities and portions of its baseload fleet. NRG believes that it can successfully execute this strategy by leveraging its expertise in marketing power and ancillary services, its knowledge of markets, its balanced financial structure and its diverse portfolio of power generation assets.

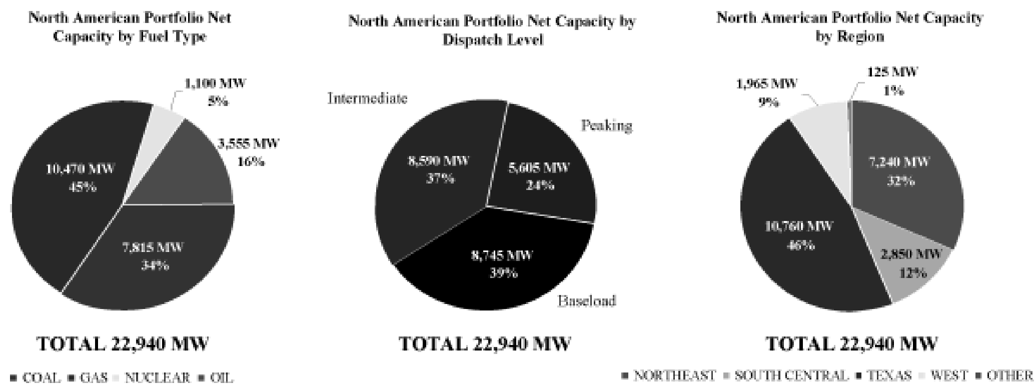
Pursue strategic acquisitions and divestures — NRG will continue to pursue selective acquisitions, joint ventures and divestitures to enhance its asset mix and competitive position in the Company's core regions. NRG intends to concentrate on opportunities that present attractive risk-adjusted returns. NRG will also opportunistically pursue other strategic transactions, including mergers, acquisitions or divestitures.

Competition and Competitive Strengths

Competition — Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. NRG competes on the basis of the location of its plants and owning multiple plants in its regions, which increases the stability and reliability of its energy supply. Wholesale power generation is basically a local business that is currently highly fragmented relative to other commodity industries and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identity of the companies NRG competes against depending on the market.

Scale and diversity of assets — NRG has one of the largest and most diversified power generation portfolios in the United States, with approximately 22,940 MW of generation capacity in 207 active generating units at 45 plants as of December 31, 2006. The Company's power generation assets are diversified by fuel-type, dispatch level and region, which help mitigate the risks associated with fuel price volatility and market demand cycles. NRG's U.S. baseload facilities, which consist of approximately 8,745 MW of generation capacity measured as of December 31, 2006, provide the Company with a significant source of stable cash flow, while its intermediate and peaking facilities, with approximately 14,195 MW of generation capacity as of December 31, 2006, provide NRG with opportunities to capture the significant upside potential that can arise from time to time during periods of high demand. In addition, approximately 15% of the Company's domestic generation facilities have dual or multiple fuel capability, which allows most of these plants to dispatch with the lowest cost fuel option.

The following chart demonstrates the diversification of NRG's domestic power generation assets as of December 31, 2006:



Reliability of future cash flows — NRG has sold forward or otherwise hedged a significant portion of its expected baseload generation capacity through 2012. The Company has the capacity and intent to enter into additional hedges in later years when market conditions are favorable. In addition, as of December 31, 2006, the Company has purchased forward under fixed price contracts (with contractually-specified price escalators) to provide fuel for approximately 73% of its expected baseload coal generation output from 2007 to 2012. These forward positions provide a stable and reliable source of future cash flow for NRG's investors, while preserving a portion of its generation portfolio for opportunistic sales to take advantage of market dynamics.

Favorable market dynamics for baseload power plants — In 2006, approximately 83% of the Company's domestic generation was fueled by coal or nuclear fuel. In many of the competitive markets where NRG operates, the price of power is typically set by the marginal costs of natural gas-fired and oil-fired power plants that currently have substantially higher variable costs than solid fuel baseload power plants. As a result of NRG's lower marginal cost for baseload coal and nuclear generation assets, the Company expects these ERCOT assets to generate power nearly 100% of the time they are available.

Locational advantages — Many of NRG's generation assets are located within densely populated areas that are characterized by significant constraints on the transmission of power from generators outside the region. Consequently, these assets are able to benefit from the higher prices that prevail for energy in these markets during periods of transmission constraints. NRG has generation assets located within New York City, southwestern Connecticut, Houston and the Los Angeles and San Diego load basins; all areas with constraints on the transmission of electricity. This gives the Company the opportunity to capture additional revenues through offering capacity to retail electric providers and others, selling power at prevailing market prices during periods of peak demand and providing ancillary services in support of system reliability. These facilities are often ideally situated for repowering or the addition of new capacity, as well, because their location and existing infrastructure give them significant advantages over newly developed sites in their regions.

Performance Metrics

The following table contains a summary of NRG's operating revenues by segment for the year ended December 31, 2006. The table also reflects the realignment of the Company's new segment structure as discussed in Item 15 — Note 17, *Segment Reporting,* to the Consolidated Financial Statements.

Region	Energy Revenues	Capacity Revenues	Risk Management Activities	Contract Amortization	Thermal Revenues	Hedge Reset	Other Revenues(c)	Total Operating Revenues
				(In millions)				
Texas(a)	$ 1,726	$ 849	$ (30)	$ 609	$ —	$ (129)	$ 63	$ 3,088
Northeast	966	321	144	—	—	—	112	1,543
South Central	334	199	13	19	—	—	5	570
West(b)	75	68	(3)	—	—	—	6	146
International	80	79	—	—	—	—	14	173
Thermal	12	—	—	—	124	—	16	152
Corporate/Eliminations	—	—	—	—	—	—	(49)	(49)
Total	$ 3,193	$ 1,516	$ 124	$ 628	$ 124	$ (129)	$ 167	$ 5,623

(a) For the period February 2, 2006 — December 31, 2006.

(b) Includes fully consolidated results of WCP for the period April 1, 2006 — December 31, 2006.

(c) Includes operations and maintenance fees, sale of natural gas, sale of emission allowances, and revenues from ancillary services.

In understanding NRG's business, the Company believes that certain performance metrics are particularly important. These are industry statistics defined by the North American Electric Reliability Council and are more fully described below:

Annual Equivalent Availability Factor, or EAF: The percentage of time in one year that a generating unit is able to produce electricity, adjusted to take into account times when the unit is unavailable and able to produce its full rated output.

Gross heat rate: NRG calculates the gross heat rate for the Company's fossil-fired power plants by dividing the average amount of fuel in BTUs that it takes to generate one kWh of electricity by the generator output.

Net Capacity Factor: The net amount of electricity that a generating unit produces over a period of time divided by the net amount of electricity it could have produced if it had run at full power over that time period. The net amount of electricity produced is the total amount of electricity generated minus the amount of electricity used during generation.

The tables below present the North American power generation performance metrics for the Company's power plants discussed above for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006				
Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/KWh	Net Capacity Factor
		(In thousands of MWh)			
Texas[a]	10,760	44,910	91.0%	10,300	41.0%
Northeast[b]	7,240	13,309	85.8	10,900	18.8
South Central	2,850	11,036	94.3	10,400	47.2
West[c]	1,965	1,901	89.1%	11,400	15.1%

	Year Ended December 31, 2005				
Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/KWh	Net Capacity Factor
		(In thousands of MWh)			
Northeast[b]	7,099	16,246	87.2%	11,146	22.9%
South Central	2,395	10,009	90.9	10,518	50.6
West[d]	1,044	1,794	86.5%	11,109	18.0%

(a) For the period February 2, 2006 through December 31, 2006.

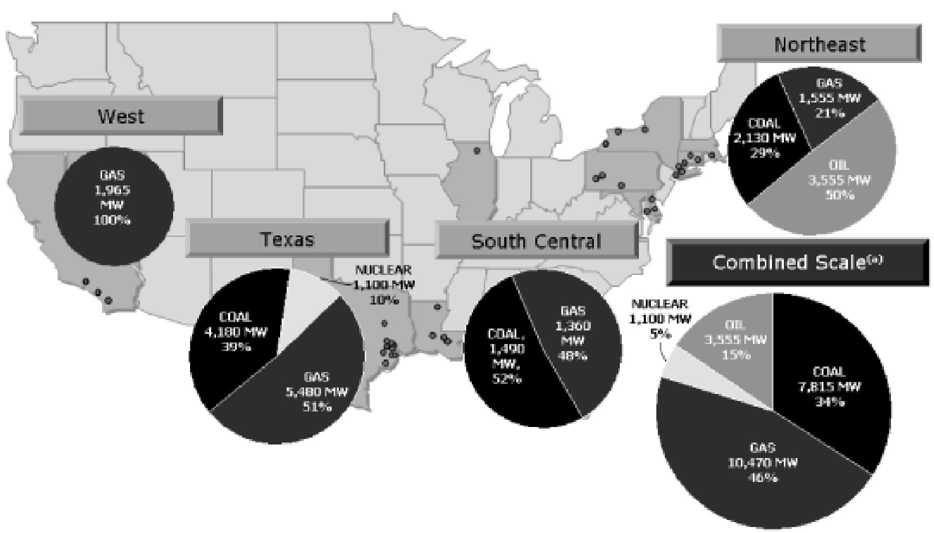
(b) Factor data and heat rate does not include the Keystone and Conemaugh facilities.

(c) Includes fully consolidated results of WCP for the period April 1, 2006 — December 31, 2006.

(d) Includes 50% of the generation owned through NRG's WCP partnership.

Generation Asset Overview

NRG has a significant power generation presence in major competitive power markets of the United States as set forth in the map below:



(a) Includes 125 MW as part of NRG's Thermal assets. For combined scale, approximately 3,430 MW is dual-fuel capable. Reflects only domestic generation capacity as of December 31, 2006.

As of December 31, 2006, the Company's power generation assets consisted of approximately 10,470 MW of gas-fired; 7,815 MW coal-fired; 3,555 MW of oil-fired and 1,100 MW of nuclear generating capacity in the United States. In addition, NRG also owns approximately 1,230 MW of thermal capacity as well as 1,235 MW of power generation capacity overseas. The Company's North American power generation portfolio by dispatch level is comprised of approximately 39% baseload, 37% intermediate and 24% of peaking units. NRG uses hedging strategies which may include power and natural gas forward sales contracts to manage the commodity price risk associated with the Company's generation assets, and are primarily around the Company's baseload generation assets. In addition, these hedging strategies also provide for stable cash flow and earnings predictability.

The following table summarizes NRG's North American baseload capacity and the corresponding revenues resulting from baseload hedge agreements extending beyond December 31, 2006 through 2012:

	2007	2008	2009	2010	2011	2012	Annual Average for 2007-2012
			(In millions unless otherwise stated)				
Net Baseload Capacity (MW)	8,800	8,730	8,730	8,621	8,621	8,621	8,687
Forecasted Baseload Capacity (MW)	7,493	7,394	7,358	7,305	7,208	7,269	7,338
Total Baseload Sales (MW)(a)	7,263	6,105	5,370	4,334	4,679	1,767	4,920
Percentage Baseload Capacity Sold Forward(b)	97%	83%	73%	59%	65%	24%	67%
Total Forward Hedged Revenues(c)(d)	$3,582	$ 2,803	$2,524	$ 1,931	$ 1,934	$ 617	$ 2,232
Weighted Average Hedged Price ($ per MWh)(c)	$ 56	$ 52	$ 54	$ 51	$ 47	$ 40	$ 50
Weighted Average Hedged Price ($ per MWh) excluding South Central region(d)	$ 61	$ 57	$ 59	$ 56	$ 51	$ 49	$ 56

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

(b) Percentage hedged is based on total MW sold as power and gas converted using the method as described in (a) above divided by the forecasted baseload capacity.

(c) Represents all North American baseload sales including power contract prices in the Texas and South Central regions which are comprised of a fixed demand charge exclusive of a fixed energy charge, with the transaction price related to these contracts being the sum of both charges.

(d) The South Central region's weighted average hedged prices ranges from $33/MWh — $35/MWh due to legacy cooperative load contracts entered into at prices significantly below current market levels.

(e) Includes contracted revenues subject to hedge accounting, market-to-market, and normal purchases and normal sales accounting treatment.

The following is a discussion of NRG's generation assets by segment for the year ended December 31, 2006. This discussion reflects the realignment of the Company's new segment structure as discussed in Item 15 — Note 17, *Segment Reporting,* to the Consolidated Financial Statements in this Form 10-K.

Texas Region — As of December 31, 2006, NRG's generation assets in the Texas region consisted of approximately 5,280 MW of baseload generation assets and approximately 5,480 MW of intermediate and peaking natural gas-fired assets. NRG realizes a substantial portion of its revenue and cash flow from the sale of power from the Company's three baseload power plants located in the ERCOT market that use solid fuel: W. A. Parish which uses coal, Limestone which uses lignite and coal, and an undivided 44% interest in two nuclear generating units at STP which uses nuclear fuel. Power plants are generally dispatched in order of lowest operating cost and as of December 31, 2006, approximately 72% of the net generation capacity in the ERCOT market was natural gas-fired. In the current natural gas price environment, NRG's three baseload facilities have significantly lower operating costs than gas plants. NRG expects these three facilities to operate nearly 100% of the time, subject to planned and forced outages.

Northeast Region — As of December 31, 2006, NRG generation assets in the Northeast region of the United States consisted of approximately 7,240 MW generation capacity from the Company's power plants within the control areas of the New York Independent System Operator, or NYISO, the Independent System Operator — New England, or ISO-NE, and the PJM Interconnection LLC, or PJM. Certain of these assets are located in transmission constrained areas, including approximately 1,415 MW of in-city New York City generation capacity and approximately 535 MW of southwest Connecticut generation capacity. As of December 31, 2006, NRG's generation assets in the Northeast region consisted of approximately 1,960 MW of baseload generation assets and approximately 5,280 MW of intermediate and peaking assets.

South Central Region — As of December 31, 2006, NRG generation assets in the South Central region of the United States consisted of approximately 2,850 MW of generation capacity, making NRG the third largest generator in the Southeastern Electric Reliability Council/Entergy, or SERC-Entergy, region. The Company's generation assets in the South Central region consists of its primary asset, Big Cajun II, a coal-fired plant located near Baton Rouge, Louisiana which has approximately 1,490 MW of baseload generation assets and 1,360 MW of intermediate and peaking assets. An annual average of 1,164 MW of baseload generation capacity has been contracted through eleven cooperatives within the region through 2025.

West Region — On March 31, 2006, NRG acquired Dynegy, Inc.'s 50% ownership interest in WCP Holdings to become sole owner of power plants with generation capacity of approximately 1,825 MW in the West region of the United States. These assets, combined with approximately 140 MW of existing wholly owned capacity in the Western Electricity Coordinating Council, brings NRG's total generation to approximately 1,965 MW in the West region as of December 31, 2006. On January 3, 2007, NRG completed the sale of the Red Bluff and Chowchilla II power plants with a combined generation capacity of approximately 95 MW to an entity controlled by Wayzata Investment Partners LLC. Excluding these two plants, total generation for the West region was 1,870 MW.

International Region — As of December 31, 2006, NRG had net ownership in approximately 1,235 MW of power generating capacity outside the United States in Australia, Brazil, and Germany. In addition to traditional power generation facilities, NRG also owned equity interests in certain coal mines in Germany.

Thermal — NRG owns thermal and chilled water businesses that generate approximately 1,230 MW thermal equivalents. In addition, NRG's thermal segment owns certain power plants with approximately 125 MW of power generating capacity located in Delaware and in Pennsylvania.

Dispositions of Non-Strategic Assets

During 2006, NRG continued its efforts to divest the Company's interests in non-core assets. As of December 31, 2006, NRG had sold a number of consolidated businesses and equity investments in an effort to reduce the Company's debt, improve liquidity and rationalize NRG's investments.

Dispositions completed during 2006 are summarized in the following table:

Asset	Type	Segment(b)	Closing Date	Proceeds	Gain/(Loss) on Disposition	Debt Reduction
					(In millions)	
Rocky Road	Equity investment	Corporate	03/31/06	$ 45	$ —	$ —
Audrain(a)	Discontinued operation	Corporate	03/29/06	115	15	240
Cadillac	Equity investment	Corporate	04/13/06	11	11	—
James River	Equity investment	Corporate	05/15/06	8	(6)	—
Latin American Funds	Equity investment	International	06/30/06	23	3	—
Flinders	Discontinued operation	International	08/30/06	242	60	183
Resource Recovery	Discontinued operation	Corporate	11/08/06	22	5	—
Total				$ 466	$ 88	$ 423

(a) Of the $115 million in cash proceeds, approximately $20 million was paid to NRG with the balance paid to the lenders of NRG Financial Company I LLC.

(b) Reflects realignment of the Company's business segments during the fourth quarter 2006.

In addition, on January 3, 2007, NRG completed the sale of Red Bluff and Chowchilla II power plants to an entity controlled by Wayzata Investment Partners LLC.

Repowering NRG Program

NRG has announced a comprehensive portfolio redevelopment program, referred to as *Repowering NRG*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity at NRG's existing domestic sites to meet the growing demand in the Company's core markets. Through the *Repowering NRG* program, the Company anticipates retiring certain existing units and adding up to approximately 10,350 MW of new generation, with an emphasis on new baseload capacity that is supported by long-term power purchase agreements, or PPAs, and financed with limited or non-recourse project financing. NRG expects that these repowering investments will provide one or more of the following benefits: improved heat rates; lower delivered costs; expanded electricity production capability; an improved ability to dispatch economically across the merit order; increased technological and fuel diversity; and reduced environmental impacts. The Company expects that the *Repowering NRG* program will also result in indirect benefits, including the continuation of operations and retention of key personnel at its existing facilities.

A critical aspect of the *Repowering NRG* program is the extent to which the Company seeks to reduce the carbon intensity of the Company's generation fleet by developing generating facilities with zero CO_2 and low CO_2 emissions, as well as facilities that can be equipped for CO_2 separation and sequestration. As a result, the *Repowering NRG* program is important not only to NRG but also to the power industry in general. The American power industry is the primary emitter of CO_2 in the largest CO_2 emitting market on earth. As the power industry takes steps to develop the next wave of power generation infrastructure, technology and capital allocation decisions will be made which could impact GHG from power generation by either making the situation significantly worse or significantly better in terms of CO_2 intensity. Although there is no current technological solution to retro-fit existing fossil-fueled technology to capture GHG from power plant flues, there are commercially available large scale technologies for new plants that can generate power with much lower GHG emissions than traditional coal-fired generation. Given that new generation units have useful lives of up to 50 years, NRG will give full consideration to CO_2 and other emissions that contribute to GHG when making its long-term investment decisions.

As part of the *Repowering NRG* program, NRG is pursuing a five-pronged GHG emissions strategy as follows:

1. *Nuclear development* — a known, reliable source of electricity with zero emissions.

2. *IGCC development* — coal-fueled baseload generation designed to reduce the intensity of CO_2 emissions.

3. *Wind development* — renewable energy for the future with zero emissions.

4. *Public outreach* — NRG will work with government, industry and public interest groups to formulate and implement an economically and environmentally responsible GHG policy.

5. *Bridge the technology gap* — The Company has launched a number of initiatives to improve technology through R&D particularly post-combustion carbon capture, developing underground sequestration, and finding offsets that will mitigate CO_2 production.

NRG estimates that the *Repowering NRG* program, if fully implemented as currently proposed, could have a total capital cost of approximately $16 billion. While NRG believes it is extremely unlikely that the program will be fully implemented as currently proposed, the Company nonetheless expects the overall capital expenditures in connection with the program will be substantial. NRG expects to mitigate the capital cost of the program through equity partnerships and public-private partnerships, as well as through development fees for certain projects. To mitigate the investment risks, NRG anticipates entering into long-term PPAs and engineering, procurement and construction, or EPC, contracts. The Company currently expects its share of cash contributions for the projects included in the *Repowering NRG* program to range between $500 million and $2.0 billion over the next decade. However, the proposed increase in generation capacity and capital costs resulting from *Repowering NRG* could change as proposed projects are included or removed from the program due to a number of factors, including successfully obtaining required permits and long term PPAs, availability of financing on favorable terms, and achieving targeted project returns. The projects that have been identified as part of the *Repowering NRG* program are subject to change as NRG refines the program to take into account the success rate for completion of projects, changes in the targeted minimum return thresholds, and evolving market dynamics.

The following table summarizes the current projects included in the *Repowering NRG* program by fuel-type:

Fuel-type	MW
Gas	4,050
Nuclear	2,700
Coal Gasification, or IGCC	1,500
Solid Fuel	1,800
Wind	300
Total	10,350

Commercial Operations Overview

NRG seeks to maximize profitability and manage cash flow volatility through the marketing, trading and sale of energy, capacity and ancillary services into spot, intermediate and long-term markets and through the active management and trading of emissions allowances, fuel supplies and transportation-related services. The Company's principal objectives are the realization of the full market value of its asset base, including the capture of its extrinsic value, the management and mitigation of commodity market risk and the reduction of cash flow volatility over time.

NRG enters into power sales and hedging arrangements via a wide range of products and contracts, including power purchase agreements, fuel supply contracts, capacity auctions, natural gas swap agreements and other financial instruments. The power purchase agreements that NRG enters into require the Company to deliver MWh of power to its counterparties. Natural gas swap agreements and other financial instruments hedge the price NRG will receive for power to be delivered in the future.

Fuel Supply and Transportation

NRG's fuel requirements consist primarily of nuclear fuel and various forms of fossil fuel including oil, natural gas and coal, including lignite. The prices of oil, natural gas and coal are subject to macro- and micro-economic forces that can change dramatically in both the short- and long-term. The Company obtains its oil, natural gas and coal from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages, transportation availability and supplier financial stability issues can and do occur. Issues related to the sources and availability of raw materials is fairly uniform across the Company's business segments.

Coal — The Company is largely hedged for its domestic coal consumption over the next few years. Coal hedging is dynamic based on forecasted generation and market volatility. As of December 31, 2006, NRG has purchased forward under contracts to provide fuel for approximately 73% on average of the Company's requirement from 2007 through 2012; 111% in 2007 (includes inventory build in excess of the Company's forecasted coal burn requirements), 89% in 2008, 81% in 2009, 56% in 2010, 51% in 2011 and 50% in years 2012 and beyond. NRG arranges for the purchase, transportation and delivery of coal for the Company's baseload coal plants via a variety of coal purchase agreements, rail transportation agreements and rail car lease arrangements. The Company purchased approximately 35 million tons of coal in 2006, which would rank NRG as one of the largest coal purchasers in the United States.

As of December 31, 2006, NRG had approximately 7,600 privately leased or owned rail cars in the Company's transportation fleet. In addition, the Company intends to enter into contracts for delivery of additional 1,100 rail cars within the next year of which approximately 1,000 will replace a portion of the Company's existing rail car fleet. NRG has entered into rail transportation agreements with varying tenures that provide for substantially all of the Company's rail transportation requirements through the end of the decade.

Natural Gas — NRG operates a fleet of natural gas plants in the Texas, Northeast, South Central and West regions which are comprised of primarily peaking assets that run in times of high power demand. Due to the uncertainty of their dispatch, the fuel needs are managed on a spot basis as it is not prudent to forward purchase fixed price gas on units that may not run. The Company contracts for gas storage services as well as gas transportation services to ensure delivery of gas when needed.

Nuclear Fuel — STP's owners satisfy STP's fuel supply requirements by (1) acquiring uranium concentrates and contracting for conversion of the uranium concentrates into uranium hexafluoride, (2) contracting for enrichment of uranium hexafluoride and (3) contracting for fabrication of nuclear fuel assemblies. NRG is party to a number of long-term forward purchase contracts with many of the world's largest suppliers covering STP requirements for uranium and conversion services for the next five years, and with substantial portions of STP's requirements procured through the end of the next decade. NRG is party to long term contracts to procure STP's requirements for enrichment services and fuel fabrication for the life of the operating license.

Seasonality and Price Volatility

Annual and quarterly operating results can be significantly affected by weather and energy commodity price volatility. Significant other events, such as the demand for natural gas, interruptions in fuel supply infrastructure and relative levels of hydroelectric capacity can increase seasonal fuel and power price volatility. NRG derives a majority of its annual revenues in the months of May through September, when demand for electricity is the highest in its core domestic markets. Further, power price volatility is generally higher in the summer months, traditionally NRG's most important season. The Company's second most important season is the winter months of December through March when volatility and price spikes in underlying fuel prices have tended to drive seasonal electricity prices. Issues related to seasonality and price volatility are fairly uniform across the Company's business segments.

Plant Operations Overview

NRG provides support services to the Company's generation facilities to ensure that high-level performance goals are developed, best practices are shared and resources are appropriately balanced and allocated to get the best results for the Company. Performance goals are set for equivalent forced outage rates, or EFOR, availability, procurement costs, operating costs and safety.

Support services include safety, security, and systems. These services also include operations strategic planning and the development and dissemination of consistent policies and practices relating to plant operations.

To support the *Repowering NRG* program, the Company has organized its project execution process into one centralized group consisting of engineering, procurement and construction. This group has regional engineering functions combined with corporate project engineering, project management, procurement and construction functions to provide a consistent and standardized approach to the way repowering work is executed. This has enabled NRG to leverage both the procurement of major equipment as well as outside engineering resources through standardized work processes and work packaging. This process has led to identifying commonality in major equipment that can be procured from Original Equipment Manufacturers, or OEMs, as well as design processes. As a result, NRG expects to achieve cost savings by minimizing the number of outside engineering and construction resources, which provide detailed design and construction services required to complete projects, in addition to and by ensuring a consistent engineering and construction approach across all projects.

Performance Improvement, Cost and Process Control Initiatives

In 2005, NRG introduced a comprehensive, company-wide cost and revenue enhancement program with the goal of increasing its return on invested capital, or ROIC. This effort has been branded as *FORNRG,* or Focus on ROIC@NRG. Projects are focused on improving plant performance, reducing purchasing and other costs and streamlining processes. A large number of initiatives are currently under way at NRG's major baseload facilities, including forced outage reductions, achieving full load, station service reductions, and heat rate improvements. Qualifying projects are also underway at the Princeton headquarters, which have reduced paperwork burdens as well as tax and insurance costs.

During the second quarter 2006, NRG expanded the program to include the Texas Genco assets and extended the term of the program to 2009, with anticipated annual savings in excess of $200 million to be achieved through continued benefits from operational performance, cost synergies and purchasing-related initiatives, plus $50 million in cash savings. For 2006, the program has demonstrated benefits of over $140 million from operational performance, cost synergies and purchasing-related initiatives, plus $61 million in cash savings, putting the Company on track to meet its 2009 target.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that approximately $1.28 billion of environmental capital expenditures will be incurred during the period 2007 through 2012, primarily related to installation of particulate, SO_2, NO_x, and mercury controls to comply with the Clean Air Interstate Rule and Clean Air Mercury rules or alternative State regimes, to the extent more stringent than the USEPA rules, as well as installation of BTA under the Phase II 316(b) Rule. Changes to regulations or market conditions could result in changes to installed equipment timing or associated costs.

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

	Texas	Northeast	South Central (In millions)	Other	Total
2007	$ 9	$ 118	$ 40	$ 10	$ 177
2008	16	183	92	10	301
2009	19	183	167	5	374
2010	26	144	86	4	260
2011	19	30	64	1	114
2012	13	3	34	—	50
Total	$ 102	$ 661	$ 483	$ 30	$ 1,276

NRG is working to reduce a portion of the above environmental capital expenditures. First, NRG has the ability to monetize a portion of the Company's excess allowances over the 2007-2012 timeframe and still hold sufficient allowances to operate the fleet with proposed controls through at least 2020. Second, NRG's current contracts with the Company's rural electrical customers in the South Central region allow for recovery of a significant portion of the costs, along with a capital return incurred by complying with new laws, including interest over the asset life of the required expenditures. Actual recoveries will depend, among other things, on the duration of the contracts and the treatment of these expenditures.

Employees

As of December 31, 2006, NRG had 3,217 employees, approximately 1,622 of whom were covered by U.S. bargaining agreements. During 2006, the Company did not experience any significant labor stoppages or labor disputes at any of its facilities.

Regional Business Descriptions

NRG is organized into business units as described below, with each of the Company's core regions operating as a separate business segment. As of December 31, 2006, NRG realigned the Company's segment structure. For a further discussion on the realignment of the Company's operating segments and for financial information on NRG's operations by segment, see Item 15 — Note 17, *Segment Reporting*, to the Consolidated Financial Statements.

TEXAS

NRG's largest business unit is located in Texas and is comprised of investments in generation facilities located in the physical control areas of the ERCOT market. These assets were acquired on February 2, 2006 as part of the acquisition of Texas Genco LLC.

Operating Strategy

The Company's business in Texas is comprised of two sets of assets: a regionally diverse set of three large solid-fuel baseload plants and a set of gas-fired plants located in and around Houston. NRG's operating strategy to maximize value and opportunity across these assets is to (1) ensure the availability of the baseload plants to fulfill their commercial obligations under long-term forward sales contracts already in place, (2) manage the gas assets for profitability while ensuring the reliability and flexibility of power supply to the Houston market, (3) take advantage of the skill sets and market/regulatory knowledge to grow the business through incremental capacity uprates and repowering development of solid-fuel baseload and gas-fired units, and (4) play a leading role in the development of the ERCOT market by active membership and participation in market and regulatory issues.

NRG's strategy is to sell forward a majority of its solid-fuel baseload capacity in the ERCOT market under long-term contracts or to enter into hedges by using natural gas as a proxy for power prices. Accordingly, the Company's primary focus will be to keep these solid-fuel baseload units running efficiently. With respect to gas-fired assets, NRG will continue a dual path of contracting forward a significant portion of gas-fired capacity one to two years out while holding a portion for back-up in case there is an operational issue with one of the baseload units. For the gas-fired capacity sold forward, the Company will offer a range of products including where the customer has the right to dispatch capacity as the customer needs. For the gas-fired capacity that NRG will continue to sell commercially into the market, the Company will focus on making this capacity available to the market whenever it is economic to run.

The generation performance by fuel-type for the recent three-year period is as shown below:

	Net Generation		
	2006	2005	2004
	(In thousands of MWh)		
Coal	31,371	31,299	31,222
Gas	7,983	6,806	7,701
Nuclear[(a)]	9,385	6,412	6,580
Total	48,739	44,517	45,503

(a) MWh information reflects the undivided interest in total MWh generated by STP. On May 19, 2005, Texas Genco LLC increased its undivided interest in STP from 30.8% to 44.0%

Generation Facilities

As of December 31, 2006, NRG's generation facilities in Texas consisted of approximately 10,760 MW of generation capacity. The following table describes NRG's electric power generation plants and generation capacity as of December 31, 2006:

Plant	Location	% Owned	Net Generation Capacity (MW)(c)	Primary Fuel-type
Solid Fuel Baseload Units:				
W. A. Parish(a)	Thompsons, TX	100.0	2,480	Coal
Limestone	Jewett, TX	100.0	1,700	Lignite/Coal
South Texas Project(b)	Bay City, TX	44.0	1,100	Nuclear
Total Solid Fuel Baseload			5,280	
Operating Natural Gas-Fired Units:				
Cedar Bayou	Baytown, TX	100.0	1,500	Natural Gas
T. H. Wharton	Houston, TX	100.0	1,025	Natural Gas
W. A. Parish (Natural gas)(a)	Thompsons, TX	100.0	1,190	Natural Gas
S. R. Bertron	Deer Park, TX	100.0	840	Natural Gas
Greens Bayou	Houston, TX	100.0	760	Natural Gas
San Jacinto	LaPorte, TX	100.0	165	Natural Gas
Total Operating Natural Gas-Fired			5,480	
Total Operating Capacity			**10,760**	

(a) W. A. Parish has nine units, four of which are baseload coal-fired units and five of which are natural gas-fired units.

(b) Generation capacity figure consists of the Company's 44.0% undivided interest in the two units of STP.

(c) Actual capacity can vary depending on factors including weather conditions, operational conditions and other factors. ERCOT requires periodic demonstration of capability, and the capacity may vary individually and in the aggregate from time to time. Excludes 2,970 MW of mothballed capacity available for redevelopment.

The following is a description of NRG's most significant revenue generating plants in the Texas region:

W.A. Parish — NRG's W.A. Parish plant is one of the largest fossil-fired plants in the United States based on total MWs of generation capacity. This plant's power generation units include four coal-fired steam generation units with an aggregate generation capacity of 2,480 MW as of December 31, 2006. Two of these units are 650 MW steam units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 570 MW and 610 MW steam units that were placed in commercial service in June 1980 and December 1982, respectively. All four units are serviced by two competing railroads that diversify NRG's coal transportation options at competitive prices. Each of the four coal-fired units have low-NO_x burners and SCR, installed to reduce NO_x emissions and baghouses to reduce particulates. In addition, W.A. Parish Unit 8 has a scrubber installed to reduce SO_2 emissions. Plant uprate projects completed in 2006 uprated the net generation capacity of W.A. Parish by 17 MW.

Limestone — NRG's Limestone plant is a lignite and coal-fired plant located approximately 140 miles northwest of Houston. This plant includes two steam generation units with an aggregate generation capacity of 1,700 MW as of December 31, 2006. The first unit is an 835 MW steam unit that was placed in commercial service in December 1985. The second unit is an 865 MW steam unit that was placed in commercial service in December 1986. Limestone primarily burns lignite from an on-site mine, but also burns low sulfur coal and petroleum coke. This serves to lower average fuel costs by eliminating fuel transportation costs, which can represent up to two-thirds of delivered fuel costs for plants of this type. NRG owns the mining equipment and facilities and a portion of the lignite reserves located at the mine. Mining operations are conducted by Texas Westmoreland Coal Co., a single purpose, wholly-owned subsidiary of Westmoreland Coal Company and the owner of a substantial portion of the remaining lignite reserves. Both units have installed low-NO_x burners to reduce NO_x emissions and scrubbers to reduce SO_2 emissions. In the second quarter of 2006, NRG replaced the high pressure and intermediate pressure turbines, rewound the generator and replaced the main generator step-up transformer of Limestone Unit 2. These upgrades increased the generation capacity by 86 MW.

South Texas Project Electric Generating Station, or STP — STP is one of the newest and largest nuclear-powered generation plants in the United States based on total megawatts of generation capacity. This plant is located approximately 90 miles south of downtown Houston, near Bay City, Texas and consists of two generation units each representing approximately 1,250 MW of generation capacity. STP's two generation units commenced operations in August 1988 and June 1989, respectively. For the year ended December 31, 2006, STP had a zero percent forced outage rate and a 97% net capacity factor.

STP is currently owned as a tenancy in common between NRG and two other co-owners. NRG owns a 44%, approximately 1,100 MW, interest in STP, the City of San Antonio owns a 40% interest and the City of Austin owns the remaining 16% interest. Each co-owner retains its undivided ownership interest in the two nuclear-fueled generation units and the electrical output from those units. Except for certain plant shutdown and decommissioning costs and NRC licensing liabilities, NRG is severally liable, but not jointly liable, for the expenses and liabilities of STP. The four original co-owners of STP organized South Texas Project Nuclear Operating Company, or STPNOC, to operate and maintain STP. STPNOC is managed by a board of directors composed of one director appointed by each of the three co-owners, along with the chief executive officer of STPNOC. STPNOC is the NRC-licensed operator of STP. No single owner controls STPNOC and all decisions must be approved by two or more owners who collectively control more than 60% of the interests.

The two STP generation units operate under licenses granted by the NRC that expire in 2027 and 2028, respectively. These licenses may be extended for additional 20-year terms if the project satisfies NRC requirements. Adequate provisions exist for long-term on-site storage of spent nuclear fuel throughout the remaining life of the existing STP plant licenses.

Repowering NRG — Texas

As part of the Company's *Repowering NRG* program, NRG has identified a number of proposed projects in Texas that could add important generation capacity to the State. These include, at present, one or more Houston gas-fired generation projects and wind projects, a large baseload coal project, and two new nuclear units. These projects are designed to meet the growing electrical needs of the State of Texas in a pragmatic and environmentally responsible way. Using a balanced portfolio of fuels and technologies, these projects would provide Texas with both new baseload generation, as well as intermediate and peaking generation units that will follow load and provide ancillary services.

The following table summarizes the proposed projects currently included in the *Repowering NRG* program in Texas:

Facility	Fuel-type	Technology
Cedar Bayou	Gas	Simple/Combined Cycle
Limestone — unit 3	Coal	Pulverized Coal
STP — Units 3&4	Nuclear	ABWR
Wind Power	Wind	Wind turbines

Cedar Bayou — In November 2006, NRG filed for a permit with the Texas Commission for Environmental Quality, or TCEQ, to repower single and combined cycle gas units consisting of up to 900 MW at NRG's Cedar Bayou facility. The Company expects to receive permits and interconnection studies during the second half of 2007.

Limestone — NRG is proposing to repower an 800 MW pulverized baseload coal unit at the Company's Limestone facility in central Texas, referred to as Limestone-3. Limestone-3 would be fueled primarily by PRB coal.

STP — NRG is proposing the addition of two nuclear reactors (Units 3 and 4) at the STP nuclear project. Commercial operations are proposed for late 2014 for Unit 3 and late 2015 for Unit 4. NRG has begun licensing efforts and the Company anticipates filing a Combined Operating License Application with the NRC during the second half of 2007. NRG is proposing to use General Electric's Advanced Boiling Water Reactor, or ABWR, technology, which is rated at approximately 1,350 MW per reactor.

Wind — The Company has 100-300 MW of wind projects under active development in Texas.

Market Framework

The ERCOT market is one of the nation's largest and fastest growing power markets. It represents approximately 85% of the demand for power in Texas and covers the whole state, with the exception of the far west (El Paso), a large part of the Texas Panhandle and two small areas in the eastern part of the state. From 1994 through 2006, peak hourly demand in the ERCOT market grew at a compound annual rate of 3.0%, compared to a compound annual rate of growth of 2.1% in the United States for the same period. For 2006, hourly demand ranged from a low of 20,276 MW to a high of 63,056 MW. ERCOT has limited interconnections compared to other markets in the United States — currently limited to 856 MW of generation capacity, and wholesale transactions within the ERCOT market are not subject to regulation by the Federal Energy Regulatory Commission, or FERC. Any wholesale producer of power that qualifies as a power generation company under the Texas electric restructuring law and that can access the ERCOT electric power grid is allowed to sell power in the ERCOT market at unregulated rates.

The ERCOT market has experienced significant construction of new generation plants in recent years, with over 20,000 MW of mostly natural gas-fired combined cycle generation capacity added to the market in the first half of this decade. As of December 31, 2006, aggregate net generation capacity of approximately 76,964 MW existed in the ERCOT market, of which 72.1% was natural gas-fired. Approximately 20,616 MW, or 26.7%, was lower marginal cost generation capacity such as coal, lignite and nuclear plants. NRG's coal and nuclear fuel baseload plants represent approximately 5,280 MW, or 26%, of the total solid fuel baseload net generation capacity in the ERCOT market. ERCOT has established a target equilibrium reserve margin level of approximately 12.5%; the reserve margin at December 31, 2006, was 16.4%, forecast to drop to 11.4% for 2008 per ERCOT's latest Capacity Demand and Reserve Report. With the exception of wind generation units, there has been very little generation that has come online since 2004, and the Company expects reserve margins to decrease through 2010 primarily due to load growth. Many new projects have been announced that if materialized would begin to increase the reserve margin after 2010.

In the ERCOT market, buyers and sellers enter into bilateral wholesale capacity, power and ancillary services contracts or may participate in the centralized ancillary services market, including balancing energy, which ERCOT administers. An October 1, 2005 *"Report on Existing and Potential Electric System Constraints and Needs"* found that natural gas-fired power plants set the market price of power more than 90% of the time in the ERCOT market. As a result of NRG's lower marginal cost for baseload coal and nuclear generation assets, the Company expects these ERCOT assets to generate power nearly 100% of the time they are available.

The ERCOT market is currently divided into four regions or congestion zones, namely: North, Houston, South and West, which reflect transmission constraints that are commercially significant and which have limits as to the amount of power that can flow across zones. NRG's W. A. Parish plant and all its natural gas-fired plants are located in the Houston zone. NRG's Limestone plant is located in the North zone with STP located in the South zone.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Council, or NERC. The PUCT has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of power supply across Texas's main interconnected power transmission grid. ERCOT is responsible for facilitating reliable operations of the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that power production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers. Unlike power pools with independent operators in other regions of the country, the ERCOT market is not a centrally dispatched power pool and ERCOT does not procure power on behalf of its members other than to maintain the reliable operations of the transmission system. ERCOT also serves as an agent for procuring ancillary services for those who elect not to provide their own ancillary services.

Power sales or purchases from one location to another may be constrained by the power transfer capability between locations. Under current ERCOT protocol, the commercially significant constraints and the transfer capabilities along these paths are reassessed every year and congestion costs are directly assigned to those parties causing the congestion. This has the potential to increase power generators' exposure to the congestion costs associated with transferring power between zones.

The PUCT has adopted a rule directing ERCOT to develop and implement a wholesale market design that, among other things, includes a day ahead energy market and replaces the existing zonal wholesale market design with a nodal market design that is based on locational marginal prices for power. See also, *Regional Regulatory Developments — Texas Region.* One of the stated purposes of the proposed market restructuring is to reduce local (intra-zonal) transmission congestion costs. The market redesign project is expected to take effect in late 2008. NRG expects that implementation of any new market design will require modifications to its existing procedures and systems. Although NRG does not expect the Company's competitive position in the ERCOT market to be materially adversely affected by the proposed market restructuring, the Company does not know for certain how the planned market restructuring will affect its revenues, and some of NRG's plants in ERCOT may experience adverse pricing effects due to their location on the transmission grid.

NORTHEAST

NRG's second largest asset base is located in the Northeast region of the United States and is comprised of investments in generation facilities primarily located in the physical control areas of NYISO, the ISO-NE and PJM.

Operating Strategy

The Northeast region's strategy is focused on optimizing the value of NRG's broad and varied generation portfolio in the three interconnected and actively traded competitive markets: the NYISO, the ISO-NE and the PJM. In the Northeast markets, load-serving entities generally lack their own generation capacity, with much of the generation base aging and the current ownership of the generation highly disaggregated. Thus, commodity prices are more volatile on an as-delivered basis than in other NRG regions due to the distance and occasional physical constraints that impact the delivery of fuel into the region. In this environment, NRG seeks both to enhance its ability to be the low cost wholesale generator capable of delivering wholesale power to load centers within the region from multiple locations using multiple fuel sources, and to be properly compensated for delivering such wholesale power and related services. The generation performance by fuel-type for the recent three-year period is as shown below:

	Net Generation		
	2006	2005	2004
	(In thousands of MWh)		
Coal	11,042	11,363	11,694
Oil	1,217	3,148	1,429
Gas	1,050	1,735	1,136
Total	13,309	16,246	14,259

NRG is focused on capturing the locational value of its plants that are located in or near load centers and inside chronic transmission constraints, in order to improve the economic rationale for repowering of those sites. NRG does this primarily through the advocacy of capacity market reforms. The Company has seen some success in these efforts with the start of the Locational Forward Reserve Markets, or LFRM, in the New England Power Pool, or NEPOOL, which, were effective October 1, 2006, and, in addition, with the start of transition capacity payments which were effective December 1, 2006, together acting as a prelude to the full implementation of the Forward Capacity Market, or FCM, which begins June 1, 2010. Further, on December 22, 2006, FERC approved a settlement regarding PJM's reliability pricing model, or RPM, effective June 1, 2007.

RMR Agreements — Several of the Northeast region's Connecticut assets are located in transmission-constrained load pockets and have been designated as required to be available to ISO-NE to ensure reliability. These assets are subject to reliability must-run, or RMR, agreements, which are contracts under which NRG agrees to maintain its facilities to be available to run when needed, and are paid to provide these capability services based on the Company's costs. During 2006, Middletown, Montville and Devon were covered by an RMR agreement.

Effective January 1, 2007, the region's Devon plant is no longer covered by an RMR agreement but operates now on a merchant basis. On January 12, 2007, FERC approved the ISO-NE request to eliminate Peaking Unit Safe Harbor, or PUSH, bidding effective June 19, 2007. This decision adversely impacts the value of generation from the Norwalk Harbor plant. NRG anticipates that it will file for an RMR agreement for this plant to be effective upon the elimination of PUSH bidding. To that end, NRG has received a determination letter from ISO-NE that this plant is needed for reliability service.

Generation Facilities

As of December 31, 2006, NRG's generation facilities in the Northeast region consisted of approximately 7,240 MW of generation capacity, including assets located in transmission constrained areas, such as in-city New York City — 1,415 MW and southwest Connecticut — 535 MW.

The Northeast region power generation assets are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity(a)	Primary Fuel-type
Oswego	Oswego, NY	100.0	1,635	Oil
Arthur Kill	Staten Island, NY	100.0	865	Natural Gas
Middletown	Middletown, CT	100.0	770	Oil
Indian River	Millsboro, DE	100.0	780	Coal
Astoria Gas Turbines	Queens, NY	100.0	550	Natural Gas
Huntley	Tonawanda, NY	100.0	550	Coal
Dunkirk	Dunkirk, NY	100.0	585	Coal
Montville	Uncasville, CT	100.0	500	Oil
Norwalk Harbor	So. Norwalk, CT	100.0	340	Oil
Devon	Milford, CT	100.0	140	Natural Gas
Vienna	Vienna, MD	100.0	170	Oil
Somerset Power	Somerset, MA	100.0	125	Coal
Connecticut Remote Turbines	Four locations in CT	100.0	105	Oil
Conemaugh	New Florence, PA	3.7	65	Coal
Keystone	Shelocta, PA	3.7	60	Coal
Total Northeast Region			**7,240**	

(a) Excludes 365 MW of inactive capacity.

The following is a description of NRG's most significant revenue generating plants in the Northeast region:

Arthur Kill — NRG's Arthur Kill plant is a natural gas-fired power plant consisting of three units and is located on the west side of Staten Island, New York. The plant produces an aggregate generation capacity of 865 MW from two intermediate load units (Units 20 and 30) and one peak load unit (Unit GT-1). Unit 20 produces an aggregate generation capacity of 350 MW and was installed in 1959. Unit 30 produces an aggregate generation capacity of 500 MW and was installed in 1969. Both Unit 20 and Unit 30 were converted from coal-fired to natural gas-fired facilities in the early 1990s. Unit GT-1 produces an aggregate generation capacity of 15 MW and is activated when ConEd issues a maximum generation alarm on hot days and during thunderstorms.

Astoria Gas Turbine — Located in Astoria, Queens, New York, the NRG Astoria Gas Turbine facility occupies approximately 15 acres within the greater Astoria Generating complex which includes several competing generating facilities. NRG's Astoria Gas Turbine facility has an aggregate generation capacity of approximately 550 MW from 19 operational combustion turbine generators classified into three types of turbines. The first group consists of 12 gas-fired Pratt & Whitney GG-4 Twin Packs in Buildings 2, 3 and 4, which have a net generating capacity of 145 MW per building. The second group consists of Westinghouse Industrial Combustion

Turbines #191A in Buildings 5, 7 and 8 that fire on liquid distillate with a net generating capacity of approximately 12 MW per building. The third group consists of Westinghouse Industrial Gas Turbines #251GG located in Buildings 10, 11, 12 and 13 and fired on liquid distillate with a net generation capacity of 20 MW per building. The Astoria units also supply Black Start Service to the NYISO. The site also contains tankage for distillate fuel with a capacity of 86,000 barrels.

Dunkirk — The Dunkirk plant is a coal-fired plant located on Lake Erie in Dunkirk, New York. This plant produces an aggregate generation capacity of 585 MW from four baseload units. Units 1 and 2 produce up to 95 MW each and were put in service in 1950, and Units 3 and 4 produce approximately 195 MW each and were put in service in 1959 and 1960, respectively. In the spring of 2006, the plant completed changes to switch from eastern bituminous coal to low sulfur PRB coal in order to comply with various federal and state emissions standards, as well as the New York Department of Environmental Conservation, or NYSDEC, settlement referred to in the following paragraph.

Huntley — The Huntley plant is a coal-fired plant consisting of six units and is located in Tonawanda, New York, approximately three miles north of Buffalo. The plant has a generation capacity of 550 MW from two intermediate load units (Units 65 and 66) and two baseload units (Units 67 and 68). Units 67 and 68 generate a net capacity of approximately 190 MW each, and were put in service in 1957 and 1958, respectively. Units 65 and 66 generate a net capacity of 85 MW each and were put in service between 1942 and 1954. Units 63 and 64 are inactive and were officially retired in May 2006. On November 30, 2006, NRG gave notice to the New York Department of Public Service of the Company's intent to retire Units 65 and 66 effective June 3, 2007 pursuant to a settlement agreement reached with NYSDEC in January 2005. Per that agreement, NRG will reduce NO_x and SO_2 emissions from the Company's Huntley and Dunkirk plants through 2013 in the aggregate by over 8,090 lbs and 8,690 lbs, respectively. A large portion of these reductions will be achieved by switching to low sulfur western coal and related projects for which NRG has already expended or committed significant capital.

Indian River — The Indian River Power plant is a coal-fired plant located in southern Delaware on a 1,170 acre site. The plant consists of four coal-fired steam electric units, Units 1 through 4 and one 15 MW combustion turbine, bringing total plant capacity to approximately 780 MW. Units 1 and 2 are each 80 MW of capacity and were placed in service in 1957 and 1959, respectively. Unit 3 is 165 MW of capacity and was placed in service in 1970, while Unit 4 is 440 MW of capacity and was placed in service in 1980. Units 3 and 4 are equipped with SNCR systems, for the reduction of NO_x emissions. All four units are equipped with electrostatic precipitators to remove fly ash from the flue gases as well as low NO_x burners with over fired air to control NO_x emissions. Units 1, 2 and 3 combust eastern bituminous coal, while Unit 4 is fueled with low sulfur compliance coal.

Repowering NRG — Northeast Region

The *Repowering NRG* program in the Northeast is focused on developing the region's existing facilities, including using IGCC technology and coal in New York and Delaware, in addition to using combined cycle gas turbines and gas peakers (some with dual fuel capability on oil) in the region.

The following table summarizes the proposed projects currently included in the *Repowering NRG* program in the Northeast region:

Facility	Fuel-type	Technology
Huntley	Coal	IGCC
Indian River	Coal	IGCC
Montville	Gas/Oil	Combined Cycle Gas Turbine
Middletown	Gas/Oil	Gas Peakers
Devon	Gas/Oil	Gas Peakers

Huntley — In December 2006, NRG won a conditional award in a competitive bid process with the New York Power Authority, or NYPA, to build a 600 MW IGCC plant at the Company's Huntley facility. The bid included selling capacity and energy to NYPA under a long term PPA. As part of the conditional award, NYPA entered into a strategic alliance with NRG to pursue support from federal, state and local programs in order to close the perceived pricing gap between NRG's proposal and NYPA's requirements, while preserving the material benefits of NRG's proposal relating to innovative clean coal power generation, including CO_2 capture and geologic sequestration plans.

Indian River — NRG also submitted a bid in December 2006 for the development of a similar IGCC plant at the Company's Indian River facility in response to a Request for Proposals, or RFP, issued by Delmarva Power and Light. NRG's bid proposed a 400 MW long term PPA for energy and capacity from the IGCC facility. The bid is currently under review and a formal award decision is scheduled to occur in the second quarter of 2007. If the bid is accepted, NRG expects to negotiate the terms of the PPA and obtain regulatory approval by the middle of 2007.

Connecticut — In December 2006, NRG submitted bids to repower a number of its existing facilities in Connecticut, in response to the State of Connecticut's RFP process. The bids included separate proposals offering a total of approximately 1,000 MW of new capacity. The largest proposal includes a 630 MW combined cycle unit at the Company's Montville site. The project covered by this proposal, if accepted, could be converted to an IGCC plant at a later date in response to any state energy and environmental policy objectives requiring baseload capacity that utilizes a plentiful domestic fuel source, such as coal. In addition, this conversion has the potential to bring material environmental benefits to the State of Connecticut, including the ability to capture and potentially sequester CO_2. NRG has also submitted bids for a new gas-fired peaking capacity at the Company's Middletown and Devon sites.

Market Framework

Although each of the three Northeast ISOs and their respective energy markets are functionally, administratively and operationally independent, they all follow, to a certain extent, similar market designs. Each ISO dispatches power plants to meet system energy and reliability needs, and settles physical power deliveries at Locational Marginal Prices, or LMPs, which reflect the value of energy at a specific location at the specific time it is delivered. This value is determined by an ISO-administered auction process, which evaluates and selects the least costly supplier offers or bids to create a reliable and least-cost dispatch. The ISO-sponsored LMP energy markets consist of two separate and characteristically distinct settlement time frames. The first is a security-constrained, financially firm, day-ahead unit commitment market. The second is a security-constrained, financially settled, real-time dispatch and balancing market. Prices paid in these LMP energy markets, however, are affected by, among other things, market mitigation measures, which can result in lower prices associated with certain generating units that are mitigated because they are deemed to have locational market power, and by $1,000/MWh energy market price caps that are in place in all three northeast ISOs.

In addition to energy delivery, the ISOs manage secondary markets for installed capacity, ancillary services and financial transmission rights. All of the three Northeast ISOs have realized, however, that they are not capable of supporting needed investment in new generation without well designed capacity and ancillary service markets. NYISO's capacity market was the first to receive approval of its proposed demand curve and locational capacity reforms (which are intended to better reflect locational values of capacity resources). ISO-NE and PJM are in the process of implementing their respective versions of reformed capacity markets, namely, a forward capacity market, or FCM, in ISO-NE, and a reliability pricing model, or RPM, proposal in PJM. ISO-NE has instituted a transitional payment for capacity starting December 1, 2006, which starts at a price of $3.05/kW-month and gradually rises to $4.10/kW-month through June 1, 2010, when the FCM market takes effect. In addition, ISO-NE instituted its LFRM market effective October 1, 2006 which provides a capacity payment for qualifying quick start units. NRG bid and was awarded 292 MW of LFRM capacity in the first auction which cleared at the capped rate of $14/kW-month. As indicated above, FERC approved a settlement of the PJM RPM market which will be effective June 1, 2007. For a further discussion, see Item 15 — Note 22 *Regulatory Matters*, to the Consolidated Financial Statements.

SOUTH CENTRAL

As of December 31, 2006, NRG owned approximately 2,850 MW of generating capacity in the South Central region of the United States. The region lacks a regional transmission organization or ISO and, therefore, remains a bilateral market, making it less efficient than a region with an ISO-administered energy market using large scale economic dispatch, such as the Northeast region. NRG operates the LaGen Control Area which encompasses the generating facilities and the Company's cooperative load. As a result, the LaGen control area is capable of providing control area services, in addition to wholesale power, that allows NRG to provide full requirement services to load-serving entities, thus making the LaGen Control Area a competitive alternative to the integrated utilities operating in the region.

Operating Strategy

NRG's South Central region seeks to capitalize on two factors: (1) its position as a significant coal-fired generator in a market that is highly dependent on natural gas for power generation, and (2) its long-term contractual and historical service relationship with eleven rural cooperatives around Louisiana. NRG's South Central region works with its cooperative customers to improve contract administration, to expand their and the Company's customer bases on terms advantageous to all parties and, in some cases, to modify the terms of the Company's contracts with respect to its current or new customers.

The generation performance by fuel-type for the recent three-year period is as shown below:

	Net Generation		
	2006	2005	2004
	(In thousands of MWh)		
Coal	10,968	9,924	10,353
Gas	68	85	8
Total	11,036	10,009	10,361

Generation Facilities

NRG's generating assets in the South Central region consist primarily of its net ownership of power generation facilities in New Roads, Louisiana, which is referred to as Big Cajun II, and also includes the Sterlington, Rockford, Bayou Cove and Big Cajun peaking facilities.

NRG's power generation assets in the South Central region as of December 31, 2006 are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity (MW)	Primary Fuel-type
Big Cajun II[(a)]	New Roads, LA	86.0	1,490	Coal
Bayou Cove	Jennings, LA	100.0	300	Natural Gas
Big Cajun I — (Peakers) Units 3 & 4	Jarreau, LA	100.0	210	Natural Gas
Big Cajun I — Units 1 & 2	Jarreau, LA	100.0	220	Natural Gas/Oil
Rockford I	Rockford, IL	100.0	300	Natural Gas
Rockford II	Rockford, IL	100.0	145	Natural Gas
Sterlington	Sterlington, LA	100.0	185	Natural Gas
Total South Central			**2,850**	

(a) NRG owns 100% of Units 1 & 2; 58% of Unit 3

Big Cajun II — NRG's Big Cajun II plant is a coal-fired, sub-critical baseload plant located along the banks of the Mississippi River, near Baton Rouge, Louisiana. This plant includes three coal-fired generation units (Units 1, 2 and 3) with an aggregate generation capacity of 1,730 MW as of December 31, 2006, and generation capacity per unit of 580 MW, 575 MW and 575 MW, respectively. The plant uses coal supplied from the Powder River Basin and was commissioned between 1981 and 1983. NRG owns 100% of Units 1 and 2 and a 58% undivided interest in Unit 3 for an aggregate owned capacity of 1,490 MW of the plant. All three units have been upgraded with low NO_x burners and overfire air. The Unit 1 generator has recently been rewound and was optimized with a modern turbine/exciter control system. Units 2 and 3 are planned for generator rewinds, turbine/exciter control replacements and additional neural net systems in future years. These efficiency improvements are expected to cost approximately $30 million.

Repowering NRG — South Central Region

The region's *Repowering NRG* strategy is focused on expanding generation capacity at the Company's Big Cajun facilities, using coal and petcoke as fuel for the plants under best available control technology.

The following table summarizes the proposed projects currently included in the *Repowering NRG* program in the South Central region:

Facility	Fuel-type	Technology
Big Cajun-II — Unit 4	Coal	Pulverized Coal (BACT)
Big Cajun-I	Pet coke/Coal	Fluidized Bed Boiler

Big Cajun II — Unit 4 — The Company continues the development of a new 775 MW super critical coal-fired generating unit at its Big Cajun II facility. On April 28, 2006, NRG filed an application with the Louisiana Department of Environmental Quality, or LADEQ, to modify the existing permit to allow the Big Cajun II Unit 4 to utilize bituminous, in addition to sub-bituminous, coal. NRG has also entered into project development agreements with potential equity partners for certain ownership interests in Unit 4. However, NRG cannot predict the outcome of its application for the issuance of the modified permit at this time.

Big Cajun I — On May 26, 2006, NRG filed with LADEQ a request for an air permit for the addition of a 230 MW facility at the Company's Big Cajun I facility. This proposed facility will have the ability to utilize petroleum coke, coal, or biomass as its fuel source.

Market Framework

NRG's assets in the South Central region are located within the franchise territories of vertically integrated utilities, primarily Entergy Corp., or Entergy. Entergy performs the scheduling, reserve and reliability functions that are administered by the ISOs in certain other regions of the United States and Canada. Although the reliability functions performed are essentially the same, the primary differences between these markets lie in the physical delivery and price discovery mechanisms. In the South Central region, all power sales and purchases are consummated bilaterally between individual counterparties. Transacting counterparties are required to reserve and purchase transmission services from the relevant transmission owners at their FERC-approved tariff rates. Included with these transmission services are the reserve and ancillary costs.

As of December 31, 2006, NRG had long-term all-requirements contracts with eleven Louisiana distribution cooperatives with initial terms ranging from five to twenty-five years. The region had seven contracts that expire in 2025, with the remaining four contracts expiring between 2009 and 2014. In addition, NRG also has certain long-term contracts with the Municipal Energy Authority of Mississippi, South Mississippi Electric Power Association, and Southwestern Electric Power Company, which collectively comprise an additional 13% of region's contract load requirement.

During peak demand periods, NRG's Big Cajun II assets are insufficient to serve the requirements of the customers under these contracts, and at such times NRG typically purchases power from other power producers in the region, frequently at higher prices than can be recovered under the Company's contracts. As the loads of the region's customers grow, the Company can expect this imbalance to worsen, unless NRG is successful in renegotiating the terms of these long-term contracts. NRG has been successful in negotiating contract modifications with several of the region's long-term cooperative customers, which has prevented the addition of large industrial or municipal loads at the contract rates. Also, to minimize this risk during the peak summer and winter seasons, the Company has been successful in entering into tolling agreements, which effectively reduce the need for spot market purchases.

WEST

NRG's portfolio in the West region currently consists of the El Segundo Generating Station, the Encina Generating Station and 13 combustion turbines with total generation capacity of approximately 1,965 MW. On March 31, 2006, NRG purchased Dynegy Inc's 50% ownership interest in WCP and became the sole owner of the WCP assets. In addition, NRG owns a 50% interest in the Saguaro power plant located in Nevada. On January 3, 2007, NRG sold the Red Bluff and the Chowchilla II power plants to Wayzata Investment Partners LLC.

Operating Strategy

NRG's West region strategy is focused on maximizing the cash flow and value associated with its generating plants while protecting and potentially realizing the commercial value of the underlying real estate. There are three principal components to this strategy: (1) responding to expected market demand, initially in load serving entity RFOs and eventually into a capacity market, and (2) using existing emission credits to permit new more efficient generating units at existing sites or siting plants at less valuable property and optimizing the value of the region's coastal property for other purposes.

The Company's Encina Station has sold all energy and capacity, 965 MW, in the aggregate, to SDG&E through 2009, on a tolling basis, and recovers its operating costs plus a capacity payment. The El Segundo Station has sold all energy and capacity, 670 MW, in the aggregate, to a load-serving entity through April 30, 2008, on a tolling basis, and recovers its operating costs plus a capacity payment. The San Diego Combustion Turbines, 190 MW, in the aggregate, are subject to an RMR agreement with the CAISO through calendar year 2007, on a tolling basis, and recover their costs plus a return of investment.

The Saguaro power plant is located in Henderson, Nevada, and is contracted to Nevada Power and two steam hosts. The Saguaro plant is contracted to Nevada Power through 2022, one steam host, referred to as Pioneer, whose contract expires in 2007, with a negotiated renewal, and a steam off taker, Ocean Spray, whose contract runs through 2015. Saguaro Power Company, LP, the project company, procures fuel in the open market. NRG manages its share of any fuel price risk through NRG's commodity price risk strategy.

Generation Facilities

NRG's power generation assets in the West region as of December 31, 2006 are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity (MW)	Primary Fuel-type
Encina	Carlsbad, CA	100.0	965	Natural Gas
El Segundo	El Segundo, CA	100.0	670	Natural Gas
Cabrillo II	San Diego, CA	100.0	190	Natural Gas
Red Bluff[(a)]	Northern CA	100.0	45	Natural Gas
Chowchilla[(a)]	Northern CA	100.0	50	Natural Gas
Saguaro	Henderson, NV	50.0	45	Natural Gas
Total West Region			**1,965**	

(a) Sold on January 3, 2007

The following are descriptions of the Company's most significant revenue generating plants in the West region:

Encina — The Encina Station is located in Carlsbad, California and has a combined generating capacity of 965 MW from five fossil-fuel steam-electric generating units and one combustion turbine. The five fossil-fuel steam-electric units provide intermediate load services and primarily use natural gas but also maintain dual fuel capability. Dual fuel capability allows the units to use oil for emergency reliability backup only under a gas supply force majeure conditions. Also located at the Encina Station is a combustion turbine that provides peaking services of 15 MW. Units 1, 2 and 3 each have a generation capacity of approximately 107 MW and were installed in 1954, 1956 and 1958, respectively. Units 4 and 5 have a generation capacity of approximately 300 MW and 330 MW respectively, and were installed in 1973 and 1978. The combustion turbine was installed in 1966. Units 1, 2 and 3 are projected to be retired after 2010. Low NO_x burner modifications and SCR equipment has been installed on Units 1, 2, 3, 4 and 5.

El Segundo — The El Segundo plant is located in El Segundo, California and produces an aggregate generation capacity of 670 MW from two gas-fired intermediate load units (Units 3 and 4). These units, which have a generation capacity of 335 MW each, were installed in 1964 and 1965, respectively. SCR equipment has been installed on Units 3 and 4.

Repowering NRG — West Region

The region's *Repowering NRG* strategy is focused on the construction of new capacity to meet increasing local requirements using natural gas at the Company's existing facilities, as well as the development of potential wind projects through the Company's wholly-owned subsidiary, Padoma Wind Power, LLC.

The following table summarizes the proposed projects currently included in the *Repowering NRG* program in the West region.

Facility	Fuel-type	Technology
Long Beach	Gas	Simple Cycle Gas Turbine
Long Beach Repower	Gas	Combined Cycle Gas Turbine
Encina Peakers	Gas	Simple Cycle Gas Turbine
El Segundo 1&2	Gas	Combined Cycle Gas Turbine
Wind Power — California	Wind	Wind turbines
El Segundo 3&4	Gas	Combined Cycle Gas Turbine

Long Beach — In November 2006, NRG was awarded a 260 MW PPA by Southern California Edison to repower Units 1-4 at the Company's Long Beach Generating Station in Long Beach, California. The PPA term commences August 1, 2007 and continues for ten years.

El Segundo 1& 2 Repower Project — NRG has permits from the California Energy Commission and Air District to construct a new gas-fired combined cycle plant at the Company's El Segundo facility to replace the retired units at the site. NRG anticipates seeking amendments to these permits to substitute equipment that will not require the use of once-through sea water cooling. The reconfigured project is included in a load-serving entity's RFO process which is scheduled to announce PPA contract awards for new capacity in early 2008.

In addition, the Company has submitted bids to one of the load-serving entities for two more projects in the West region. The Company expects to know the outcome of these bids sometime during the second half of 2007.

Market Framework

NRG's assets in the West region consist primarily of older, higher heat rate, gas-fired plants in southern California. These plants, while older and less efficient than newer combined cycle plants, are under tolling agreements for 2007. CAISO has designated all of the units comprising El Segundo, Encina and Cabrillo II to be capacity that meets the local capacity procurement requirements of the local load-serving entities. At times, all of the plants have been designated as RMR, which entitles designated plants to certain fixed-cost payments from the CAISO for the right to dispatch those units during periods of locational constraints. Currently, the El Segundo unit does not have an RMR agreement with CAISO, but has been designated as a local capacity resource in the Western Los Angeles area and has a tolling agreement for its full capacity with a local major utility for the period May 1, 2006 through April 30, 2008. All units at Encina and Cabrillo II have been designated as local capacity resources for the San Diego load pocket and were designated as RMR units for 2007. Per the RMR agreement, CAISO has an option to renew those units for RMR service into 2008. Encina has a tolling agreement for its full capacity with SDG&E for the period January 1, 2007 through December 31, 2009.

INTERNATIONAL

As of December 31, 2006, NRG, through certain foreign subsidiaries, had investments in power generation projects located in Australia, Germany and Brazil with approximately 1,235 MW of total generating capacity. In addition, NRG owns interests in coal mines located in Germany. The Company's strategy is to maximize its return on investment and therefore concentrates on contract management; monitoring of its facility operators to ensure safe, profitable and sustainable operations; management of cash flow and finances; and growth of its businesses through investments in projects related to current businesses.

NRG's international power generation assets as of December 31, 2006 are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity	Primary Fuel-type
Gladstone	Australia	37.5	605	Coal
Schkopau	Germany	41.9	400	Lignite
MIBRAG	Germany	50.0	75	Lignite
ITISA	Brazil	99.2	155	Hydro
Total International			**1,235**	

Australia — On June 8, 2006, NRG announced the sale of the Company's 37.5% equity interest in the Gladstone power station, or Gladstone, and its associated 100% owned NRG Gladstone Operating Services to Transfield Services, an Australia-based provider of operations, maintenance, ownership and asset management services for a purchase price of approximately $189 million (AU$239 million) subject to customary purchase price adjustments, plus assumption of NRG's share of Gladstone's unconsolidated debt and cash of approximately $61 million (AU$77 million) and approximately $28 million (AU$35 million), respectively. After-tax cash proceeds are expected to be in excess of $185 million (AU$234 million). The sale is pending until NRG satisfies certain conditions, particularly the securing of certain consents and waivers from the other owners of the project, or agrees to complete the sale on alternative terms. NRG is seeking to close the transaction in 2007.

Germany — NRG's interests in Germany include a 50% equity interest in MIBRAG, which mines approximately 20 million metric tons of lignite per year and owns 150 MW of electric generation capacity, and a 41.9% equity interest in Schkopau, a 900 MW generating plant fueled with lignite from MIBRAG. NRG does not have direct operational control of either of these facilities.

Approximately 89% of MIBRAG's revenues are generated from lignite sales. MIBRAG's generation capacity comprises three plants, 40% of whose output is used to power MIBRAG's mining operations and the balance sold under contract to EnviaM, the local distribution utility. NRG, through its wholly-owned subsidiary Saale Energie Gesellschaft, or SEG, owns 400 MW of the Schkopau plant's electric capacity which is sold under a long term contract to Vattenfall Europe Generation.

Brazil — NRG owns a 155 MW hydro-electric power plant located in the state of Mato Grosso, Brazil. NRG currently has a 99.2% interest in the plant.

THERMAL

Through its wholly-owned subsidiary, NRG Thermal LLC, or NRG Thermal, the Company owns thermal and chilled water businesses that have a steam and chilled water capacity of approximately 1,230 megawatt thermal equivalents, or MWt. As of December 31, 2006, NRG Thermal provided steam heating to approximately 550 customers and chilled water to 95 customers in five different cities in the United States. The Company's thermal businesses in Pittsburgh, Harrisburg and San Francisco are regulated by their respective state Public Utility Commission. The other thermal businesses are subject to the terms of the contract with the off-takers. In addition, NRG Thermal owns and operates three thermal projects that serve industrial and government customers with high-pressure steam and hot water. NRG Thermal also owns a 90 MW combustion turbine peaking generation facility and a 12 MW coal-fired cogeneration facility in Dover, Delaware as well as a 16 MW gas-fired project in

Harrisburg, Pennsylvania. Approximately 40% of NRG Thermal's revenues are derived from its district heating and chilled water business in Minneapolis, Minnesota.

Regulatory Matters

As operators of power plants and participants in wholesale energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include CFTC, FERC, NRC, PUCT and other public utility commissions in certain states where NRG's generating assets are located. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO markets in which it participates.

The operations of, and wholesale electric sales from, NRG's Texas region are not subject to regulation by FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. As discussed below, these operations are subject to regulation by PUCT, as well as to regulation by the NRC with respect to the Company's ownership interest in STP.

Commodities Futures Trading Commission, or CFTC

CFTC, among other things, has regulatory oversight authority over the trading of electricity and gas commodities, including financial products and derivatives, under the Commodity Exchange Act, or CEA. Specifically, under existing statutory authority, CFTC has the authority to commence enforcement actions and seek injunctive relief against any person, whenever that person appears to be engaged in the communication of false or misleading or knowingly inaccurate reports concerning market information or conditions that affected or tended to affect the price of natural gas, a commodity in interstate commerce, or actions intended to or attempting to manipulate commodity markets. CFTC also has the authority to seek civil monetary penalties, as well as the ability to make referrals to the Department of Justice for criminal prosecution, in connection with any conduct that violates the CEA. Proposals are pending in Congress to expand CFTC oversight of the over-the-counter markets and bilateral financial transactions.

Federal Energy Regulatory Commission

FERC, among other things, regulates the transmission and the wholesale sale of electricity in interstate commerce under the authority of the Federal Power Act, or FPA. In addition, under existing regulations, FERC determines whether an entity owning a generation facility is an Exempt Wholesale Generator, or EWG, as defined in the Public Utility Holding Company Act of 2005, or PUHCA of 2005. FERC also determines whether a generation facility meets the ownership and technical criteria of a Qualifying Facility, or QF, under Public Utility Regulatory Policies Act of 1978, or PURPA. Each of NRG's U.S. generating facilities has either been determined by FERC to qualify as a QF, or the subsidiary owning the facility has been determined to be a EWG.

Federal Power Act — The FPA gives FERC exclusive rate-making jurisdiction over the wholesale sale of electricity and transmission of electricity in interstate commerce. Under the FPA, FERC, with certain exceptions, regulates the owners of facilities used for the wholesale sale of electricity or transmission in interstate commerce as public utilities. The FPA also gives FERC jurisdiction to review certain transactions and numerous other activities of public utilities. NRG's QFs are currently exempt from the FERC's rate regulation under Sections 205 and 206 of the FPA to the extent that sales are made pursuant to a state regulatory authority's implementation of PURPA.

Public utilities under the FPA are required to obtain FERC's acceptance, pursuant to Section 205 of the FPA, of their rate schedules for the wholesale sale of electricity. All of NRG's non-QF generating and power marketing companies in the United States make sales of electricity pursuant to market-based rates authorized by FERC. FERC's orders that grant NRG's generating and power marketing companies market-based rate authority reserve the right to revoke or revise that authority if FERC subsequently determines that NRG can exercise market power, create barriers to entry, or engage in abusive affiliate transactions. In addition, NRG's market-based sales are subject to certain market behavior rules and, if any of its generating or power marketing companies were deemed to have violated any one of those rules, they would be subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of their market-based rate authority, as well as criminal and civil penalties. As a condition to the orders granting NRG market-based rate authority, every three years NRG is required to file a market update to demonstrate that it continues to meet FERC's standards with respect to generating market power and other criteria used to evaluate whether entities qualify for market-based rates. NRG is also required to report to FERC any material changes in status that would reflect a departure from the characteristics that FERC relied upon when granting NRG's various generating and power marketing companies' market-based rates. If NRG's generating and power marketing companies were to lose their market-based rate authority, such companies would be required to obtain FERC's acceptance of a cost-of-service rate schedule and could become subject to the accounting, record-keeping, and reporting requirements that are imposed on utilities with cost-based rate schedules.

Section 203 of the FPA requires FERC's prior approval for the transfer of control of assets subject to FERC's jurisdiction. Section 204 of the FPA gives FERC jurisdiction over a public utility's issuance of securities or assumption of liabilities. However, FERC typically grants blanket approval for future securities issuances and the assumption of liabilities to entities with market-based rate authority. In the event that one of NRG's generating and power marketing companies were to lose its market-based rate authority, such company's future securities issuances or assumption of liabilities could require prior approval from FERC.

In compliance with Section 215 of the Energy Policy Act of 2005, or EPAct of 2005, FERC has approved the North American Electric Reliability Corporation, or NERC, as the national Energy Reliability Organization, or ERO. As the ERO, NERC will be responsible for the development and enforcement of mandatory reliability standards for the wholesale electric power system. NRG is responsible for complying with the standards in the regions in which it operates. The ERO will have the ability to assess financial penalties for non-compliance beginning in June 2007.

Public Utility Holding Company Act of 2005 — PUHCA of 2005 provides FERC with certain authority over and access to books and records of public utility holding companies not otherwise exempt by virtue of their ownership of EWGs, QFs, and Foreign Utility Companies, or FUCOs. NRG is a public utility holding company, but because all of the Company's generating facilities have QF status or are owned through EWGs or FUCOs, it is exempt from the accounting, record retention, and reporting requirements of PUHCA.

Public Utility Regulatory Policies Act — PURPA was passed in 1978 in large part to promote increased energy efficiency and development of independent power producers. PURPA created QFs to further both goals, and FERC is primarily charged with administering PURPA as it applies to QFs. As discussed above, under current law, some categories of QFs may be exempt from regulation under the FPA as public utilities. PURPA incentives also initially included a requirement that utilities must buy and sell power to QFs. Among other things, EPAct of 2005 provides for the elimination of the obligation imposed on certain utilities to purchase power from QFs at an avoided cost rate under certain conditions. However, the purchase obligation is only eliminated if FERC first finds that a QF has non-discriminatory access to wholesale energy markets having certain characteristics, including nondiscriminatory transmission and interconnection services provided by a regional transmission entity in certain circumstances. Existing contracts entered into under PURPA are not expected to be impacted; however, certain of NRG's QFs currently interconnect into markets that may meet the qualifications for elimination of the PURPA purchase requirement. If the obligation to purchase from some or all of NRG's QFs is terminated, NRG will need to find alternative purchasers for the output of these QFs once their current contracts expire. Such alternative purchases will be at prevailing market rates, which may not be as favorable as the terms of NRG's PURPA sales arrangements under existing contracts and thus may diminish the value of the Company's QFs. In addition, under FERC regulations for implementing EPAct of 2005, QFs not making sales pursuant to state-approved avoided cost rates will become subject to FERC's ratemaking authority under the FPA and be required to obtain market rate authority in order to be allowed to sell power at market-based rates.

Nuclear Regulatory Commission, or NRC

The NRC is authorized under the Atomic Energy Act of 1954, as amended, or the AEA, among other things, to grant licenses for, and regulate the operation of, commercial nuclear power reactors. As a holder of an ownership interest in STP, NRG is an NRC licensee and is subject to NRC regulation. The NRC license gives the Company the right to only possess an interest in STP but not to operate it. Operating authority under the NRC operating license for STP is held by STPNOC. NRC regulation involves licensing, inspection, enforcement, testing, evaluation, and modification of all aspects of plant design and operation including the right to order a plant shutdown, technical and financial qualifications, and decommissioning funding assurance in light of NRC safety and environmental requirements. In addition, NRC's written approval is required prior to a licensee transferring an interest in its license, either directly or indirectly. As a possession-only licensee, i.e., non-operating co-owner, the NRC's regulation of NRG is primarily focused on the Company's ability to meet its financial and decommissioning funding assurance obligations. In connection with the NRC license, the Company and its subsidiaries have a support agreement to provide up to $120 million to support operations at STP.

Decommissioning Trusts — Upon expiration of the operating terms of the operation licenses for the two generating units at STP, currently scheduled for 2027 and 2028, the co-owners of STP are required under federal law to decontaminate and decommission the STP facility. Under NRC regulations, a power reactor licensee generally must pre-fund the full amount of its estimated NRC decommissioning obligations unless it is a rate-regulated utility, or a state or municipal entity that sets its own rates, or has the benefit of a state-mandated non-bypassable charge available to periodically fund the decommissioning trust such that the trust, plus allowable earnings, will equal the estimated decommissioning obligations by the time the decommissioning is expected to begin.

As a result of the acquisition of Texas Genco LLC, NRG through its 44% ownership interest has become the beneficiary of decommissioning trusts that have been established to provide funding for decontamination and decommissioning of STP. CenterPoint Energy Houston Electric, LLC, or CenterPoint, and American Electric Power, or AEP, collect, through rates or other authorized charges to their electric utility customers, amounts designated for funding NRG's portion of the decommissioning of the facility.

In the event that the funds from the trusts are ultimately determined to be inadequate to decommission the STP facilities, the original owners of the Company's STP interests, CenterPoint and AEP, each will be required to collect, through their PUCT-authorized non-bypassable rates or other charges to customers, additional amounts required to fund NRG's obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective rate payers of CenterPoint or AEP, or their successors.

Public Utility Commission of Texas, or PUCT

NRG's Texas generation subsidiaries are registered as power generation companies with PUCT. PUCT also has jurisdiction over power generation companies with regard to the administration of nuclear decommissioning trusts, PUCT state-mandated capacity auctions, and the implementation of measures to mitigate undue market power that a power generation company may have and to remedy market power abuses in the ERCOT market and, indirectly, through oversight of ERCOT. PMI is registered as a power marketer with the PUCT and thus is also subject to the jurisdiction of the PUCT with respect to its sales in ERCOT.

Regional Regulatory Developments

In New England, New York, the Mid-Atlantic region, the Midwest and California, FERC has approved regional transmission organizations, also commonly referred to as independent system operators, or ISOs. Most of these ISOs administer a wholesale centralized bid-based spot market in their regions pursuant to tariffs approved by FERC and associated ISO market rules. These tariffs/market rules dictate how the capacity and energy markets operate, how market participants may make bilateral sales with one another, and how entities with market-based rates are compensated within those markets. The ISOs in these regions also control access to and the operation of the transmission grid within their regions. In Texas, pursuant to a 1999 restructuring statute, the PUCT has granted similar responsibilities to ERCOT.

NRG is affected by rule/tariff changes that occur in the ISO regions. The ISOs that oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address market power or volatility in these markets. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of NRG's generation facilities that sell capacity and energy into the wholesale power markets. In addition, new approaches to the sale of electric power have been proposed, and it is not yet clear how they will operate in times of market stress or whether they will provide adequate compensation to generators over the long term.

Texas Region

ERCOT has adopted "Texas Nodal Protocols" that will revise the wholesale market design to incorporate locational marginal pricing (in place of the current ERCOT zonal market). Major elements of the Texas Nodal Protocols include the continued capability for bilateral contracting of energy and ancillary schedules, a financially binding day-ahead market, resource-specific energy and ancillary service bid curves, the direct assignment of all congestion rents, nodal energy prices for resources, aggregation of nodal to zonal energy prices for loads, congestion revenue rights (including pre-assignment for public power entities), and pricing safeguards. The PUCT approved the Texas Nodal Protocols on April 5, 2006, and full implementation of the new market design is expected in December 2008. In other rulemakings, the PUCT has expanded its enforcement policy, increased market oversight, and established market and generator-specific data disclosure requirements designed to increase market transparency. Certain entity specific data disclosure provisions have been stayed by order of a Texas appellate court.

Northeast Region

New England — NRG's Middletown and Montville facilities continue to be operated pursuant to RMR agreements that were accepted by the Commission on February 1, 2006 (effective January 1, 2006). Unless terminated earlier, the Middletown and Montville RMR agreements are expected to terminate upon the commencement of the Forward Capacity Market, as discussed below. The Devon RMR Agreement terminated on December 31, 2006.

On March 7, 2006, a broad group of New England market participants filed a settlement that provides for interim capacity transition payments for all generators in New England for the period starting December 1, 2006 through May 31, 2010, and the establishment of FCM, commencing June 1, 2010. The FCM established by the settlement will operate an annual descending clock forward capacity auction, normally three years in advance, and will serve as the principal mechanism by which ISO-NE will obtain its installed capacity requirement. For the Company's Connecticut units subject to RMR agreements, any transition payment will be credited against the monthly availability payment for those units, resulting in no additional revenues for those units. NRG's other New England generation units are eligible for the transition payments. On June 16, 2006, FERC issued an order accepting the settlement, which was reaffirmed on rehearing by order dated October 31, 2006. On December 28, 2006, the Attorneys General of the State of Connecticut and Commonwealth of Massachusetts filed an appeal of the FERC orders accepting the settlement with U.S. Court of Appeals for the D.C. Circuit. Interim capacity transition payments provided for under the FCM settlement commenced December 1, 2006, as scheduled.

On May 12, 2006, FERC issued an order accepting ISO-NE's Ancillary Service Market Phase II package that includes a LFRM. This order was reaffirmed on rehearing on October 25, 2006. NRG's quick-start units are well-suited to provide this service. For the eight-month winter period beginning October 1, 2006, the LFRM market for Connecticut cleared at the cap of $14/kW-month. NRG sold 292 MW in the LFRM auction and expects its participation in this market to positively contribute to revenues from the region.

On January 12, 2007, FERC accepted proposed amendments to ISO-NE's market rules that eliminate the PUSH bidding mechanism effective June 19, 2007. The elimination of PUSH bidding will impact the Company's Norwalk Harbor facility, and the Company anticipates seeking an RMR agreement for Norwalk Harbor Units 1 and 2.

New York — On December 22, 2006, the NYISO filed proposed tariff revisions that impose additional market power mitigation on the current owners of its divested generation units in New York City, including NRG's Arthur Kill and Astoria facilities. The proposed mitigation effectively lowers the bid cap currently set forth in the NYISO tariff from $105/kW-year to $82/kW-year. This proposal could adversely impact capacity revenues from these units and NRG is contesting this filing before FERC.

On January 5, 2007, the Executive Committee of the New York State Reliability Council voted to change the Installed Reserve Margin, or IRM, from 18% to 16.5%. This change, which must be approved by FERC, will become effective for the May 2007 through April 2008 capacity year and will reduce the amount of capacity that must be purchased by load-serving entities.

PJM — On December 22, 2006, FERC issued an order approving the settlement agreement filed September 29, 2006, in the Reliability Pricing Model, or RPM, proceeding. The settlement agreement proposes to implement RPM, the key components of which include the determination of capacity prices through use of a downward-sloping demand curve, locational pricing, and a forward capacity market. PJM anticipates conducting its first auction for the 2007-08 delivery years in April 2007 and implementing the RPM capacity market on June 1, 2007. The RPM settlement effectively accepts PJM's August 31, 2006 filing with a number of revisions, as set forth in the settlement and December 22, 2006 order. NRG considers these market reforms to be a positive development for its assets in the region.

South Central Region

Entergy has begun to implement its Independent Coordinator of Transmission, or ICT, proposal that will provide (i) independent oversight over the operations of the Entergy transmission system, including the processing of interconnection and transmission requests; (ii) a new process and standard for assigning cost responsibility for transmission upgrades; and (iii) a new weekly procurement process that will allow both Entergy and NRG, as a purchaser of power, to more efficiently utilize the transmission system. The Southwest Power Pool has been selected as the ICT and began performing its responsibilities in November 2006.

Entergy's ICT proposal will impact both the region's existing operations by improving transmission access and competitive opportunities and the region's development opportunities by administering the interconnection process. Certain issues regarding (i) the development of the base transmission plan; (ii) control over Entergy's transmission models; and (iii) Entergy's proposal to implement participant funding, are still being contested.

West Region

On December 1, 2006, NRG filed with FERC an extension of the existing RMR agreements for NRG's Cabrillo Power I, LLC's Encina facility, and Cabrillo Power II, LLC's San Diego Jets facility for 2007, and to continue the existing rate effective January 1, 2007. On January 24, 2007, FERC accepted the Cabrillo I filing. On January 30, 2007, FERC accepted the Cabrillo II filing, subject to refund, in response to protests filed by the CPUC and CAISO, and established settlement procedures. NRG has negotiated a three-year bilateral arrangement with SDG&E for Encina that insulates Encina from any revenue impact associated with the RMR agreement.

On September 21, 2006, FERC conditionally accepted the CAISO's Market Redesign and Technology Upgrade, or MRTU, proposal which is currently scheduled to go in effect in January 31, 2008. Significant components of the MRTU include (i) locational marginal pricing of energy; (ii) a more effective congestion management system; (iii) a day-ahead market; and (iv) an increase to the existing bid caps. NRG considers these market reforms to be a positive development for its assets in the region. Several parties have requested rehearing, which remains pending.

On July 20, 2006, the CPUC issued its order towards establishing a standard Resource Adequacy Capacity Product that followed its decision to impose local capacity requirements, which took effect January 1, 2007. On the same date, the CPUC issued its order on long-term resource procurement that requires SCE to procure at least 1,500 MW.

In November 2006, NRG was awarded a 260 MW PPA by Southern California Edison to repower Units 1-4 at the Company's Long Beach Generating Station in Long Beach, California. On February 22, 2007, an intervener sought rehearing of the CPUC approval of the agreement and is contesting the PPA at FERC.

See also Item 15 — Note 22, *Regulatory Matters,* to the Consolidated Financial Statements for a further discussion.

Environmental Matters

NRG is subject to a wide range of environmental regulations across a broad number of jurisdictions in the development, ownership, construction and operation of domestic and international projects. These laws and regulations generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental laws have become increasingly stringent in recent years, especially around the regulation of air emissions from power generators. Such laws generally require regular capital expenditures for power plant upgrades, modifications and the installation of certain pollution control equipment. In general, future laws and regulations are expected to require the addition of emissions control or other environmental quality equipment or the imposition of certain restrictions on the operations of the Company's facilities. NRG expects that future liability under, or compliance with, environmental requirements could have a material effect on the Company's operations or competitive position.

Federal Environmental Initiatives

Air — On May 18, 2005, the US Environmental Protection Authority, or USEPA, published the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants. CAMR imposes limits on mercury emissions from new and existing coal-fired plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two phases, 2010 and 2018. Texas and Louisiana will adopt the CAMR federal implementation plan, or FIP, when it is finalized by USEPA. Certain states in which NRG operates coal plants in NRG's Northeast region such as Delaware, Massachusetts and New York have proposed or adopted state implementation plans in lieu of the CAMR FIP. Provisions for mercury monitoring and mitigation technologies are included in the budget and environmental capital expenditures for NRG's coal plants.

On May 12, 2005, the USEPA published the Clean Air Interstate Rule, or CAIR. This rule applies to 28 eastern states and the District of Columbia and caps SO_2 and NO_x emissions from power plants in two phases; 2010 and 2015 for SO_2 and 2009 and 2015 for NO_x. CAIR will apply to some of the Company's power plants in New York, Massachusetts, Connecticut, Delaware, Louisiana, Illinois, Pennsylvania, Maryland and Texas. On August 24, 2005, the USEPA published a proposed FIP to ensure that generators affected by CAIR reduce emissions on schedule. In parallel: (i) on December 20, 2005, the USEPA signed proposed revisions to address attainment for fine particulates, or NAAQS for PM2.5, which will require affected states to implement further rules to address SO_2 and NO_x emissions; and (ii) on November 9, 2005, the USEPA proposed the second phase of the 8-hour ozone NAAQS rule relating to NO_x emissions. A number of environmental groups, states and industry organizations challenged aspects of the CAIR. The challenges were consolidated into *South Coast Air Quality Management District v. EPA.* In a ruling on December 22, 2006, the D.C. Circuit overturned portions of USEPA's Phase I implementation rule for the new 8-hour ozone standard. Specifically, the court ruled that USEPA could revoke the 1-hour standard as long as there was no backsliding from more stringent control measures. This ruling could result in the imposition of fees under Section 185 of the Clean Air Act, or the CAA, on volatile organic carbon, or VOC, and NO_x emissions in severe non-attainment areas. The fees could be as high as $7,700/ton for emissions above 80% of baseline emissions levels. Depending on the determination of baseline emission levels, this could materially impact NRG's operations in California, New York City and Texas.

The Clean Air Visibility Rule was published by the USEPA on July 6, 2005. The rule requires regional haze controls by targeting SO_2 and NO_x emissions from sources including power plants of a certain vintage through the installation of Best Available Retrofit Technology, or BART, in certain cases. States must develop implementation plans by December 2007. Most of the Company's facilities will likely be able to satisfy their obligations under the BART rule through compliance with the more stringent CAIR. Accordingly, no material additional expenditures are anticipated beyond those required by CAIR.

Increased public concern and mounting political pressure may result in federal requirements to reduce or mitigate the effects of GHG. NRG's generating portfolio includes coal-, oil- and gas-fired plants, which emit CO_2, a GHG, and will likely be subject to proposed regulation which could affect NRG's costs of operation. NRG is taking steps now to mitigate any potential adverse impacts, including investments in non-fossil generation and investments in generation technologies that will more easily allow the company to manage and control CO_2 emissions.

In the 1990s, the USEPA commenced an industry-wide investigation of coal-fired electric generators to determine compliance with environmental requirements under the CAA associated with repairs, maintenance, modifications and operational changes made to facilities over the years. As a result, the USEPA and several states filed suits against a number of coal-fired power plants in mid-western and southern states alleging violations of the CAA New Source Review, or NSR, Prevention of Significant Deterioration, or PSD, requirements. EPA has issued an NOV against NRG's Big Cajun II plant alleging that NRG's predecessors had undertaken projects that triggered requirements under the PSD program, including the installation of emission controls. NRG has evaluated the claims and believes they have no merit. Nonetheless, NRG has had discussions with EPA about resolving the claims. See the South Central regional below for a further discussion.

Water — In July 2004, USEPA published rules governing cooling water intake structures at existing power facilities commonly referred to as the Phase II 316(b) rules. The rules specify standards for cooling water intake structures at existing power plants using the largest amounts of cooling water. These rules will require implementation of the Best Technology Available, or BTA, for minimizing adverse environmental impacts unless a facility shows that such standards would result in very high costs or little environmental benefit. On January 25, 2007, the *2nd Circuit Court of Appeals* made its decision in the *Riverkeeper vs. US EPA* appeal over the Phase II 316(b) regulation. Riverkeeper prevailed on nearly all issues and the decision essentially remands all of the important aspects of the rule back to EPA for reconsideration and restricted EPA's ability to allow generators to substitute mitigation for aquatic species losses through habitat restoration or other measures. The Phase II 316(b) regulation affects a number of NRG's plants, specifically those with once-through cooling systems. While NRG has conducted a number of the requisite studies, until all the needed studies throughout the Company's fleet have been completed, consultations on the results have occurred with USEPA or its delegated state or regional agencies, and EPA concludes its reconsideration of the 316(b) rules, it is not possible to estimate with certainty the capital costs that will be required for compliance with the Phase II 316(b) rules.

Nuclear Waste — Under the U.S. Nuclear Waste Policy Act of 1982, the federal government must remove and ultimately dispose of spent nuclear fuel and high-level radioactive waste from nuclear plants such as STP. Consistent with the Act, owners of nuclear plants, including NRG and the other owners of STP, entered into contracts setting out the obligations of the owners and the U.S. Department of Energy, or DOE, including the fees being paid by the owners for DOE's services. Since 1998, the DOE has been in default on its obligations to begin removing spent nuclear fuel and high-level radioactive waste from reactors. On January 28, 2004, Texas Genco LP and the other owners of STP filed a breach of contract suit against the DOE in order to protect against the running of a statute of limitations.

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended, the State of Texas is required to provide, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the State. The State of Texas has agreed to a compact with the state of Vermont for a disposal facility that would be located in Texas. That compact was ratified by Congress and signed by President Clinton in 1998. In 2003, the State of Texas enacted legislation allowing a private entity to be licensed to accept low-level radioactive waste for disposal. NRG intends to continue to ship low-level waste material from STP offsite for as long as an alternative disposal site is available. Should existing off-site disposal become unavailable, the low-level waste material will then be stored on-site. STP's on-site storage capacity is expected to be adequate for STP's needs until other off-site facilities become available.

Regional U.S. Environmental Initiatives

Northeast Region

NRG's facilities in the eastern US are subject to a cap-and-trade program governing NO_x emissions during the ozone season, typically from May 1 through September 30. These rules essentially require that one NO_x allowance be held for each ton of NO_x emitted. Each of NRG's facilities that are subject to these rules has been allocated NO_x emission allowances. NRG currently estimates that the portfolio total is currently sufficient to generally cover operations at these facilities through 2009, reflecting the fact that NO_x allowances are allocated on a three-year, look-back basis. However, if at any point emission allowances are insufficient for the anticipated operation of each of these facilities, NRG must purchase NO_x allowances. Any obligation to purchase a substantial number of additional NO_x allowances could have a material adverse effect on NRG's operations.

The Ozone Transport Commission, or OTC, was established by Congress and governs ozone and the NO_x budget program in certain eastern states, including Massachusetts, Connecticut, New York and Delaware. The OTC proposes to implement a regional plan containing emission reduction targets for power plants that exceed those under CAIR. The OTC targets and timelines have slipped although additional SO_2 and NO_x reductions are still in discussion. Current attention is focused on NO_x emissions from units run primarily on High Energy Demand Days, or HEDD, of which NRG owns facilities in Connecticut, Delaware and New York. NRG continues to be actively engaged in the OTC stakeholder process including providing technical expertise to improve policy decision making. While it is not possible to predict the outcome of this regional effort, to the extent that the OTC is successful in implementing emission requirements that are more stringent than existing regimes, NRG could be materially impacted.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding, or MOU, to create a Regional Greenhouse Gas initiative to establish a cap-and-trade greenhouse gas program for electric generators, referred to as RGGI. Maryland and Massachusetts have since announced their intent to join. In August 2006, the states participating in RGGI released a model rule which addresses program elements including timelines, monitoring, the use of offsets, and allowance trading. The program begins in 2009. Individual states in which NRG operates including Connecticut, Delaware, Massachusetts and New York must promulgate state rules, which can be based on the model rule, and in addition, address allowance allocations/auctions, treatment of unallocated allowances and leakage. New York issued a pre-proposal version in December 2006 which, among other things, proposes to increase MOU suggested set aside of allowances from 25% to 100% and that these allowances be auctioned. New York is accepting comments on the pre-proposal and expects to have a final rule later in 2007. Connecticut, Delaware and Massachusetts plan to develop rules in 2007. NRG has proposed clean coal IGCC projects that are carbon capture ready to meet future generation demands in both New York and Delaware and also, potentially, Connecticut. NRG continues to actively participate in state and regional RGGI proceedings.

New England — Massachusetts air regulations prescribe schedules under which six existing coal-fired power plants in-state are required to meet stringent emission limits for NO_x, SO_2, mercury, and CO_2. NRG's Somerset plant is subject to these regulations. NRG has installed natural gas reburn technology to meet the NO_x and SO_2 limits. On June 4, 2004, the Massachusetts Department of Environmental Protection, or MADEP, issued its regulation on the control of mercury emissions. The effect of this regulation is that starting October 1, 2006, Somerset will be capped at 13.1 lbs/year of mercury as of January 1, 2008 and must achieve a reduction in its mercury inlet-to-outlet concentration of 85%. NRG plans to meet the requirements through the management of our fuels and the use of early and off-site reduction credits. Additionally, NRG has entered into an agreement with MADEP to retire or repower the Somerset station by the end of 2009. A permit for repowering the facility was submitted to the MADEP in December 2006.

The Massachusetts carbon regulation 310 CMR 7.29 Emissions Standards for Power Plants requires coal-fired generation located within the state to comply with CO_2 emissions restrictions. A carbon emissions cap applies from January 1, 2006, while a rate requirement will apply in 2008. It is expected that Somerset will meet the cap from 2006 through 2007 and purchase offsets after that period. Massachusetts announced in January 2006 that they will join the other Northeast states in RGGI.

New York — Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC entered into a Consent Order with the New York State Department of Environmental Conservation, or NYSDEC, effective March 31, 2004, regarding certain alleged opacity exceedances. The Order stipulates penalties for future violations of opacity requirements and a compliance schedule. In 2006, NRG accrued amounts payable to NYSDEC of $0.2 million to cover the stipulated penalty payments.

Delaware — In November 2006, the Delaware Department of Natural Resources and Environmental Control, or DNREC, promulgated Regulation No. 1146, or Reg 1146, Electric Generating Unit Multi-Pollutant Regulation and Section 111(d) of the State Plan for the Control of Mercury Emissions from Coal-Fired Electric Steam Generating Units. These regulations govern the control of SO_2, NO_x and mercury emissions from electric generating units. NRG's current plan to install controls at the Company's Indian River facility, while on an accelerated basis, is unable to meet certain deadlines for SO_2 and NO_x controls in Phase 1, taking into account the time required, as a practical matter, to design, install and commission the necessary equipment. NRG and the owners of all other subject facilities in the state filed a challenge to Reg 1146 with the Environmental Appeals Board on December 6, 2006. In addition, NRG also filed a protective appeal with the Delaware Superior Court on December 29, 2006. NRG is unable to predict the outcome of the proceedings at this time, but failure to obtain relief may result in a material impact to the Company's Indian River facility.

On January 5, 2005, DNREC initiated a rule making to incorporate USEPA's NSR reforms within Delaware's Regulation 25. Delaware was required to revise the state's current rules and demonstrate such revisions are equivalent to, or more stringent than, the USEPA's revisedrules by January 2006, which Delaware did not meet. The state is considering a facility emissions limit that would cap all NSR applicable pollutants. The results of the rule making, expected in 2007, will impact Indian River and Dover facilities.

West Region

NRG's El Segundo Generating Station is regulated by the South Coast Air Quality Management District, or SCAQMD. Before the station's retirement as of January 1, 2005, the Long Beach Generating Station was also regulated by SCAQMD. SCAQMD approved amendments to its Regional Clean Air Incentives Market, or RECLAIM, NO_x regulations on January 7, 2005. RECLAIM is a regional emission-trading program targeting NO_x reductions to achieve state and federal ambient air quality standards for ozone. Among other changes, the amendments reduce the NO_x RECLAIM Trading Credit, or RTC, holdings of El Segundo Power, LLC and Long Beach Generation LLC facilities by certain amounts. Notwithstanding these amendments, retained RTCs are expected to be sufficient to operate El Segundo Units 3 and 4 as high as 100% capacity factor for the life of those units.

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

Nuclear Insurance

STPNOC purchases insurance coverage on behalf of NRG and the other owners of STP. STP maintains property, decontamination liability and nuclear hazard liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. Currently, STP has a $2.75 billion limit in property and decontamination liability insurance coverage, which is above the legally required minimum of $1.06 billion. The $2.75 billion includes $1 billion excess blanket coverage that is shared with two other nuclear power plants, namely Diablo Canyon and DC Cook. The deductible for property damage is $2.5 million. STP also carries a primary accidental outage policy, which allows for six weeks of indemnity at $3.5 million per week after a 17 week deductible is met. The $3.5 million weekly indemnity would be allocated between the three owners of STP according to their ownership percentages. NRG has purchased additional accidental outage coverage for its 44% ownership stake in STP. This policy provides coverage after the six week indemnity period has been paid under the primary policy, and will provide NRG $1.98 million weekly indemnity per unit for 52 weeks and $1.58 million per week for the next 71 weeks. If both units at STP are affected by an outage arising out of the same accident, weekly indemnity per unit is limited to 80% of the single unit recovery. There is no coverage for partial outages, and the outage must be the result of a property damage caused by a sudden and fortuitous event.

The Price-Anderson Act, as amended through 2025 by the Energy Policy Act of 2005, requires owners of nuclear power plants in the U.S. to purchase the maximum amount of insurance available (currently $300 million) in the insurance market for liability claims that arise in the event of a nuclear accident. In addition, the Act provides a secondary layer of protection of up to $10.5 billion. Under this provision, each licensed reactor company is obliged to contribute up to approximately $101 million per unit per accident in retrospective premiums for any single incident at any nuclear power plant. Annual installments per reactor cannot exceed $15 million. STP is a two reactor facility but NRG's liability would be capped at 44% due to the Company's ownership interest in STP. The Price-Anderson Act only covers nuclear liability associated with an accident in the course of operation of the nuclear reactor, transportation of nuclear fuel to the reactor site, storage of nuclear fuel and waste at the reactor site and the transportation of the spent nuclear fuel and nuclear waste from the nuclear reactor. Any substantial retrospective premiums imposed under the Price-Anderson Act or losses not covered by insurance could have a materially adverse effect on NRG's financial condition, the results of operations and statement of cash flows.

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products at the facility. NRG may also be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by a party in connection with hazardous material releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, or CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, or SARA, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and the courts have interpreted liability under such laws to be strict (without fault) and joint and several. Cleanup obligations can often be triggered during the closure or decommissioning of a facility, in addition to spills or other occurrences during its operations.

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 DNREC, through the Voluntary Clean-up Program to investigate the site. The Company is unable to predict the exact impact at this time.

Further details regarding our Domestic Site Remediation obligations can be found at Item 15 — Note 22, *Regulatory Matters*, to the Consolidated Financial Statements.

International Environmental Matters

Most of the foreign countries in which NRG owns or may acquire or develop independent power projects have environmental and safety laws or regulations relating to the ownership or operation of electric power generation facilities. These laws and regulations, like those in the U.S., are constantly evolving and have a significant impact on international wholesale power producers. In particular, NRG's international power generation facilities will likely be affected by emissions limitations and operational requirements imposed by the Kyoto Protocol, which is an international treaty related to greenhouse gas emissions enacted on February 16, 2005, and country-based restrictions pertaining to global climate change concerns.

NRG retains appropriate advisors in foreign countries and seeks to design its international asset management strategy to comply with each country's environmental and safety laws and regulations. There can be no assurance that changes in such laws or regulations will not adversely effect the Company's international operations.

MIBRAG/Schkopau, Germany — CO_2 emissions trading began in Germany in 2005, pursuant to European Union obligations under the Kyoto Protocol. Trading rules and emissions allocations for the second emissions trading period (2008 through 2012) have not yet been established by the regulators, therefore the impact of the new rules on NRG's German business cannot be predicted at this time. Changes to the German Emission Control Directive have specified lower NO_x emission limits for plants firing conventional fuels and co-firing waste products. The new regulations required the Mumsdorf and Deuben Power stations to install additional controls to reduce NO_x emissions in 2006. These plant modifications have been successfully completed. The regulations of the revised European Union's Groundwater Directive and Mine Wastewater Management Directive are now in effect and MIBRAG sees no negative effects on its mining operations or economics.

Available Information

NRG's annual reports on Form 10-K, quarterly reports on Form10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are available free of charge through the Company's website, www.nrgenergy.com, as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission.

Item 1A — *Risk Factors Related to NRG Energy, Inc.*

Many of NRG's power generation facilities operate, wholly or partially, without long-term power sale agreements.

Many of NRG's facilities operate as "merchant" facilities without long-term power sales agreements for some or all of their generating capacity and output, and therefore are exposed to market fluctuations. Without the benefit of long-term power sales agreements for these assets, NRG cannot be sure that we will be able to sell any or all of the power generated by these facilities at commercially attractive rates or that these facilities will be able to operate profitably. This could lead to future impairments of the Company's property, plant and equipment or to the closing of certain of its facilities, resulting in economic losses and liabilities, which could have a material adverse effect on the Company's results of operations, financial condition or cash flows.

NRG's financial performance may be impacted by changing natural gas prices, significant and unpredictable price fluctuations in the wholesale power markets and other market factors that are beyond the Company's control.

A significant percentage of the company's domestic revenues are derived from baseload power plants that are fueled by coal. In many of the competitive markets where NRG operates, the price of power typically is set by marginal cost natural gas-fired power plants that currently have substantially higher variable costs than NRG's coal-fired baseload power plants. The current pricing and cost environment allows the Company's baseload coal generation assets to earn attractive operating margins compared to plants fueled by natural gas. A decrease in natural gas prices could result in a corresponding decrease in the market price of power but would generally not affect the cost of the coal that the plants use. This could significantly reduce the operating margins of the Company's baseload generation assets and materially and adversely impact its financial performance.

In addition, because changes in power prices in the markets where NRG operates are generally correlated with changes in natural gas prices, NRG's hedging portfolio includes natural gas derivative instruments to hedge power prices for its baseload generation. If this correlation between power prices and natural gas prices is not maintained and a change in gas prices is not proportionately offset by a change in power prices, the Company's natural gas hedges may not fully cover this differential. This could have a materially adverse impact on the Company's cash flow and financial position.

Market prices for power, generation capacity and ancillary services tend to fluctuate substantially. Unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility from supply and demand imbalances, especially in the day-ahead and spot markets. Long- and short-term power prices may also fluctuate substantially due to other factors outside of the Company's control, including:

- increases and decreases in generation capacity in the Company's markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation plants, expansion of existing plants or additional transmission capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- electric supply disruptions, including plant outages and transmission disruptions;
- heat rate risk;
- weather conditions;
- changes in the demand for power or in patterns of power usage, including the potential development of demand-side management tools and practices;
- development of new fuels and new technologies for the production of power;
- regulations and actions of the ISOs; and
- federal and state power market and environmental regulation and legislation.

These factors have caused the Company's operating results to fluctuate in the past and will continue to cause them to do so in the future.

NRG's costs, results of operations, financial condition and cash flows could be adversely impacted by disruption of its fuel supplies.

NRG relies on coal, oil and natural gas to fuel a majority of its power generation facilities. Delivery of these fuels to the facilities is dependent upon the continuing financial viability of contractual counterparties as well as upon the infrastructure (including rail lines, rail cars, barge facilities, roadways, and natural gas pipelines) available to serve each generation facility. As a result, the Company is subject to the risks of disruptions or curtailments in the production of power at its generation facilities if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure.

NRG has sold forward a substantial portion of its baseload power in order to lock in long-term prices that it deemed to be favorable at the time it entered into the forward sale contracts. In order to hedge its obligations under these forward power sales contracts, the Company has entered into long-term and short-term contracts for the purchase and delivery of fuel. Many of the forward power sales contracts do not allow the Company to pass through changes in fuel costs or discharge the power sale obligations in the case of a disruption in fuel supply due to force majeure events or the default of a fuel supplier or transporter. Disruptions in the Company's fuel supplies may therefore require it to find alternative fuel sources at higher costs, to find other sources of power to deliver to counterparties at a higher cost, or to pay damages to counterparties for failure to deliver power as contracted. Any such event could have a material adverse effect on the Company's financial performance.

NRG also buys significant quantities of fuel on a short-term or spot market basis. Prices for all of the Company's fuels fluctuate, sometimes rising or falling significantly over a relatively short period of time. The price NRG can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. This may have a material adverse effect on the Company's financial performance. Changes in market prices for natural gas, coal and oil may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;
- additional generating capacity;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil, refined products and coal production levels;
- changes in market liquidity;
- federal, state and foreign governmental regulation and legislation; and
- the creditworthiness and liquidity and willingness of fuel suppliers/transporters to do business with the Company.

NRG's plant operating characteristics and equipment, particularly at its coal-fired plants, often dictate the specific fuel quality to be combusted. The availability and price of specific fuel qualities may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, coal of specific quality may not be available at any price, or the Company may not be able to transport such coal to its facilities on a timely basis. In this case, the Company may not be able to run the coal facility even if it would be profitable. Operating a coal facility with different quality coal can lead to emission or operating problems. If the Company had sold forward the power from such a coal facility, it could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on the financial results of specific plants and on the Company's results of operations.

There may be periods when NRG will not be able to meet its commitments under forward sale obligations at a reasonable cost or at all.

A substantial portion of the output from NRG's baseload facilities has been sold forward under fixed price power sales contracts through 2012, and the Company also sells forward the output from its intermediate and peaking facilities when its deems it commercially advantageous to do so. Because the obligations under most of these agreements are not contingent on a unit being available to generate power, NRG is generally required to deliver power to the buyer, even in the event of a plant outage, fuel supply disruption or a reduction in the available capacity of the unit. To the extent that the Company does not have sufficient lower cost capacity to meet its commitments under its forward sale obligations, the Company would be required to supply replacement power either by running its other, higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. If NRG fails to deliver the contracted power, it would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

In NRG's South Central region, NRG has long-term contracts with rural cooperatives that require it to serve all of the cooperatives' requirements at prices that generally reflect the costs of coal-fired generation. At times, the output from NRG's coal-fired Big Cajun II facility has been and will continue to be inadequate to serve these obligations, and when that happens the Company has typically purchased power from other power producers, often at a loss. NRG's financial returns from its South Central region are likely to deteriorate over time as the rural cooperatives grow their customer base, unless the Company is able to amend or renegotiate its contracts with the cooperatives or add generating capacity.

NRG's trading operations and the use of hedging agreements could result in financial losses that negatively impact its results of operations.

The Company typically enters into hedging agreements, including contracts to purchase or sell commodities at future dates and at fixed prices, in order to manage the commodity price risks inherent in its power generation operations. These activities, although intended to mitigate price volatility, expose the Company to other risks. When the Company sells power forward, it gives up the opportunity to sell power at higher prices in the future, which not only may result in lost opportunity costs but also may require the Company to post significant amounts of cash collateral or other credit support to its counterparties. Further, if the values of the financial contracts change in a manner that the Company does not anticipate, or if a counterparty fails to perform under a contract, it could harm the Company's business, operating results or financial position.

NRG does not typically hedge the entire exposure of its operations against commodity price volatility. To the extent it does not hedge against commodity price volatility, the Company's results of operations and financial position may be improved or diminished based upon movement in commodity prices.

NRG may engage in trading activities, including the trading of power, fuel and emissions allowances that are not directly related to the operation of the Company's generation facilities or the management of related risks. These trading activities take place in volatile markets and some of these trades could be characterized as speculative. The Company would expect to settle these trades financially rather than through the production of power or the delivery of fuel. This trading activity may expose the Company to the risk of significant financial losses which could have a material adverse effect on its business and financial condition.

NRG may not have sufficient liquidity to hedge market risks effectively.

The Company is exposed to market risks through its power marketing business, which involves the sale of energy, capacity and related products and the purchase and sale of fuel, transmission services and emission allowances. These market risks include, among other risks, volatility arising from location and timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

NRG undertakes these marketing activities through agreements with various counterparties. Many of the Company's agreements with counterparties include provisions that require the Company to provide guarantees, offset of netting arrangements, letters of credit, a second lien on assets and/or cash collateral to protect the counterparties against the risk of the Company's default or insolvency. The amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in the Company being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of the Company's strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than the Company anticipates or will be able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as a cash margin, the Company may not be able to manage price volatility effectively or to implement its strategy. An increase in the amount of letters of credit or cash collateral required to be provided to the Company's counterparties may negatively affect the Company's liquidity and financial condition.

Further, if any of NRG's facilities experience unplanned outages, the Company may be required to procure replacement power at spot market prices in order to fulfill contractual commitments. Without adequate liquidity to meet margin and collateral requirements, the Company may be exposed to significant losses, may miss significant opportunities, and may have increased exposure to the volatility of spot markets.

The accounting for NRG's hedging activities may increase the volatility in the Company's quarterly and annual financial results.

NRG engages in commodity-related marketing and price-risk management activities in order to financially hedge its exposure to market risk with respect to electricity sales from its generation assets, fuel utilized by those assets, and emission allowances.

NRG generally attempts to balance its fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for in accordance with SFAS 133, as amended, which requires the Company to record all derivatives on the balance sheet at fair value with changes in the fair value resulting from fluctuations in the underlying commodity prices immediately recognized in earnings, unless the derivative qualifies for cash flow hedge accounting treatment. Whether a derivative qualifies for cash flow hedge accounting treatment depends upon it meeting specific criteria used to determine if the cash flow hedge is and will remain appropriate for the term of the derivative. Economic hedges will not necessarily qualify for cash flow hedge accounting treatment. As a result, the Company may be unable to accurately predict the impact that its risk management decisions may have on its quarterly and annual operating results.

Competition in wholesale power markets may have a material adverse effect on NRG's results of operations, cash flows and the market value of its assets.

NRG has numerous competitors in all aspects of its business, and additional competitors may enter the industry. Because many of the Company's facilities are old, newer plants owned by the Company's competitors are often more efficient than NRG's aging plants, which may put some of these plants at a competitive disadvantage to the extent the Company's competitors are able to consume the same or less fuel as the Company's plants consume. Over time, the Company's plants may be squeezed out of their markets, or may be unable to compete with these more efficient plants.

In NRG's power marketing and commercial operations, it competes on the basis of its relative skills, financial position and access to capital with other providers of electric energy in the procurement of fuel and transportation services, and the sale of capacity, energy and related products. In order to compete successfully, the Company seeks to aggregate fuel supplies at competitive prices from different sources and locations and to efficiently utilize transportation services from third-party pipelines, railways and other fuel transporters and transmission services from electric utilities.

Other companies with which NRG competes with may have greater liquidity, greater access to credit and other financial resources, lower cost structures, more effective risk management policies and procedures, greater ability to incur losses, longer-standing relationships with customers, greater potential for profitability from ancillary services or greater flexibility in the timing of their sale of generation capacity and ancillary services than NRG does.

NRG's competitors may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion or refurbishment of their power generation facilities than NRG can. In addition, current and potential competitors may make strategic acquisitions or establish cooperative relationships among themselves or with third parties. Accordingly, it is possible that new competitors or alliances among current and new competitors may emerge and rapidly gain significant market share. There can be no assurance that NRG will be able to compete successfully against current and future competitors, and any failure to do so would have a material adverse effect on the Company's business, financial condition, results of operations and cash flow.

Operation of power generation facilities involves significant risks and hazards customary to the power industry that could have a material adverse effect on NRG's revenues and results of operations. NRG may not have adequate insurance to cover these risks and hazards.

The ongoing operation of NRG's facilities involves risks that include the breakdown or failure of equipment or processes, performance below expected levels of output or efficiency and the inability to transport the Company's product to its customers in an efficient manner due to a lack of transmission capacity. Unplanned outages of generating units, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of the Company's business. Unplanned outages typically increase the Company's operation and maintenance expenses and may reduce the Company's revenues as a result of selling fewer MWh or require NRG to incur significant costs as a result of running one of its higher cost units or obtaining replacement power from third parties in the open market to satisfy the Company's forward power sales obligations. NRG's inability to operate the Company's plants efficiently, manage capital expenditures and costs, and generate earnings and cash flow from the Company's asset-based businesses could have a material adverse effect on the Company's results of operations, financial condition or cash flows. While NRG maintains insurance, obtains warranties from vendors and obligates contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover the Company's lost revenues, increased expenses or liquidated damages payments should the Company experience equipment breakdown or non-performance by contractors or vendors.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks such as earthquake, flood, lightning, hurricane and wind, other hazards, such as fire, explosion, structural collapse and machinery failure are inherent risks in the Company's operations. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in NRG being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. NRG maintains an amount of insurance protection that it considers adequate, but the Company cannot provide any assurance that its insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which it may be subject. A successful claim for which the Company is not fully insured could hurt its financial results and materially harm NRG's financial condition. Further, due to rising insurance costs and changes in the insurance markets, NRG cannot provide any assurance that its insurance coverage will continue to be available at all or at rates or on terms similar to those presently available. Any losses not covered by insurance could have a material adverse effect on the Company's financial condition, results of operations or cash flows.

Maintenance, expansion and refurbishment of power generation facilities involve significant risks that could result in unplanned power outages or reduced output and could have a material adverse effect on NRG's results of operations, cash flow and financial condition.

Many of NRG's facilities are old and require periodic upgrading and improvement. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability.

NRG cannot be certain of the level of capital expenditures that will be required due to changing environmental and safety laws and regulations (including changes in the interpretation or enforcement thereof), needed facility repairs and unexpected events (such as natural disasters or terrorist attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on the Company's liquidity and financial condition.

If NRG makes any major modifications to its power generation facilities, the Company may be required to install the best available control technology or to achieve the lowest achievable emissions rates, as such terms are defined under the new source review provisions of the federal Clean Air Act. Any such modifications would likely result in substantial additional capital expenditures.

The Company's Repowering NRG program is subject to financing, construction, and operational risks that could adversely impact NRG's financial performance

While NRG currently intends to develop and finance the more capital intensive, solid fuel-fired projects included in the *Repowering NRG* program on a non-recourse or limited recourse basis through separate project financed entities, and intends to seek additional investments in most of these projects from third parties, NRG anticipates that it will need to make significant equity investments in these projects. NRG may also decide to develop and finance some of the projects, such as smaller gas-fired and renewable projects, using corporate financial resources rather than non-recourse debt, which could subject NRG to significant capital expenditure requirements and to risks inherent in the development and construction of new generation facilities. In addition to providing some or all of the equity required to develop and build the proposed projects, NRG's ability to finance these projects on a non-recourse basis is contingent upon a number of factors, including the terms of the engineering, procurement and construction contracts, construction costs, power purchase agreements and fuel procurement contracts, capital markets conditions, the availability of tax credits and other government incentives for certain new technologies. To the extent NRG is not able to obtain non-recourse financing for any projects or should the credit rating agencies attribute a material amount of the project finance debt to NRG's credit, the financing of the *Repowering NRG* projects could have a negative impact on the credit ratings of NRG. In addition, there are risks inherent in the development and construction of new generation facilities. Further, certain of the *Repowerng NRG* projects incorporate advanced equipment and technologies with only a modest amount of operating history in the proposed configurations. There also exists the possibility of cost overruns, schedule delays and performance risks during the construction phase, as well as the possibility of operational and contractual issues during the commercial operational life of these new generation facilities that could adversely impact NRG's financial performance.

As part of the *Repowering NRG* program, NRG may also choose to undertake the repowering, refurbishment or upgrade of current facilities based on the Company's assessment that such activity will provide adequate financial returns. Such projects often require several years of development and capital expenditures before commencement of commercial operations, and key assumptions underpinning a decision to make such an investment may prove incorrect, including assumptions regarding construction costs, timing, available financing and future fuel and power prices. The construction, expansion, modification and refurbishment of power generation facilities involve many additional risks, including:

- delays in obtaining necessary permits and licenses;
- environmental remediation of soil or groundwater at contaminated sites;
- interruptions to dispatch at the Company's facilities;
- supply interruptions;
- work stoppages;
- labor disputes;
- weather interferences;
- unforeseen engineering, environmental and geological problems;
- unanticipated cost overruns; and
- performance risks.

Any of these risks could cause NRG's financial returns on new investments to be lower than expected, or could cause the Company to operate below expected capacity or availability levels, which could result in lost revenues, increased expenses, higher maintenance costs and penalties.

Supplier and/or customer concentration at certain of NRG's facilities may expose the Company to significant financial credit or performance risks.

NRG often relies on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of certain of its facilities. If these suppliers cannot perform, the Company utilizes the marketplace to provide these services. There can be no assurance that the marketplace can provide these services as, when and where required.

At times, NRG relies on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. The Company has also hedged a portion of its exposure to power price fluctuations through forward fixed price power sales and natural gas price swap agreements. Counterparties to these agreements may breach or may be unable to perform their obligations. NRG may not be able to enter into replacement agreements on terms as favorable as its existing agreements, or at all. If the Company was unable to enter into replacement PPA's, the Company would sell its plants' power at market prices. If the Company is unable to enter into replacement fuel or fuel transportation purchase agreements, NRG would seek to purchase the Company's fuel requirements at market prices, exposing the Company to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price.

The failure of any supplier or customer to fulfill its contractual obligations to NRG could have a material adverse effect on the Company's financial results. Consequently, the financial performance of the Company's facilities is dependent on the credit quality of, and continued performance by, suppliers and customers.

NRG relies on power transmission facilities that the Company does not own or control and that are subject to transmission constraints within a number of the Company's core regions. If these facilities fail to provide NRG with adequate transmission capacity, the Company may be restricted in its ability to deliver wholesale electric power to its customers and the Company may either incur additional costs or forego revenues. Conversely, improvements to certain transmission systems could also reduce revenues.

NRG depends on transmission facilities owned and operated by others to deliver the wholesale power it sells from the Company's power generation plants to its customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate, NRG's ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, the Company's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. The Company cannot also predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

In addition, in certain of the markets in which NRG operates, energy transmission congestion may occur and the Company may be deemed responsible for congestion costs if it schedules delivery of power between congestion zones during times when congestion occurs between the zones. If NRG were liable for such congestion costs, the Company's financial results could be adversely affected.

In the California ISO, New York ISO and New England ISO markets, the Company has a significant amount of generation located in load pockets, making that generation valuable, particularly with respect to maintaining the reliability of the transmission grid. Expansion of transmission systems to reduce or eliminate these load pockets could negatively impact the value or profitability of our existing facilities in these areas.

Because NRG owns less than a majority of some of its project investments, the Company cannot exercise complete control over their operations.

NRG has limited control over the operation of some project investments and joint ventures because the Company's investments are in projects where it beneficially owns less than a majority of the ownership interests.

NRG seeks to exert a degree of influence with respect to the management and operation of projects in which it owns less than a majority of the ownership interests by negotiating to obtain positions on management committees or to receive certain limited governance rights, such as rights to veto significant actions. However, the Company may not always succeed in such negotiations. NRG may be dependent on its co-venturers to operate such projects. The Company's co-venturers may not have the level of experience, technical expertise, human resources management and other attributes necessary to operate these projects optimally. The approval of co-venturers also may be required for NRG to receive distributions of funds from projects or to transfer the Company's interest in projects.

Future acquisition activities may have adverse effects.

NRG may seek to acquire additional companies or assets in the Company's industry. The acquisition of power generation companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, the Company's acquisitions may not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

NRG's business is subject to substantial governmental regulation and may be adversely affected by legislative or regulatory changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements.

NRG's business is subject to extensive foreign, and U.S. federal, state and local laws and regulation. Compliance with the requirements under these various regulatory regimes may cause the Company to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines, and/or civil or criminal liability.

Public utilities under the Federal Power Act, or FPA, are required to obtain FERC acceptance of their rate schedules for wholesale sales of electricity. All of NRG's non-qualifying facility generating companies and power marketing affiliates in the United States make sales of electricity in interstate commerce and are public utilities for purposes of the FPA. FERC has granted each of NRG's generating and power marketing companies the authority to sell electricity at market-based rates. The FERC's orders that grant NRG's generating and power marketing companies market-based rate authority reserve the right to revoke or revise that authority if FERC subsequently determines that NRG can exercise market power in transmission or generation, create barriers to entry, or engage in abusive affiliate transactions. In addition, NRG's market-based sales are subject to certain market behavior rules, and if any of NRG's generating and power marketing companies were deemed to have violated one of those rules, they are subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of their market-based rate authority. If NRG's generating and power marketing companies were to lose their market-based rate authority, such companies would be required to obtain FERC's acceptance of a cost-of-service rate schedule and could become subject to the accounting, record-keeping, and reporting requirements that are imposed on utilities with cost-based rate schedules. This could have an adverse effect on the rates NRG charges for power from its facilities.

NRG is also affected by legislative and regulatory changes, as well as changes to market design, market rules, tariffs, cost allocations, and bidding rules that occur in the existing ISOs. The ISOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, mitigation, including price limitations, offer caps, and other mechanisms to address some of the volatility and the potential exercise of market power in these markets. These types of price limitations and other regulatory mechanisms may have an adverse effect on the profitability of NRG's generation facilities that sell energy and capacity into the wholesale power markets.

The regulatory environment applicable to the electric power industry has undergone substantial changes over the past several years as a result of restructuring initiatives at both the state and federal levels. These changes are ongoing and the Company cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on NRG's business. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism, as well as proposals to re-regulate the markets or require divestiture by generating companies to reduce their market share. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, our business prospects and financial results could be negatively impacted.

NRG's ownership interest in a nuclear power facility subjects the Company to regulations, costs and liabilities uniquely associated with these types of facilities.

Under the Atomic Energy Act of 1954, as amended, or AEA, operation of STP, of which NRG indirectly own a 44.0% interest, is subject to regulation by the Nuclear Regulatory Commission, or NRC. Such regulation includes licensing, inspection, enforcement, testing, evaluation and modification of all aspects of nuclear reactor power plant design and operation, environmental and safety performance, technical and financial qualifications, decommissioning funding assurance and transfer and foreign ownership restrictions. NRG's 44% share of the output of STP represents approximately 1,100 MW of generation capacity.

There are unique risks to owning and operating a nuclear power facility. These include liabilities related to the handling, treatment, storage, disposal, transport, release and use of radioactive materials, particularly with respect to spent nuclear fuel, and uncertainties regarding the ultimate, and potential exposure to, technical and financial risks associated with modifying or decommissioning a nuclear facility. The NRC could require the shutdown of the plant for safety reasons or refuse to permit restart of the unit after unplanned or planned outages. New or amended NRC safety and regulatory requirements may give rise to additional operation and maintenance costs and capital expenditures. STP may be obligated to continue storing spent nuclear fuel if the Department of Energy continues to fail to meet its contractual obligations to STP made pursuant to the U.S. Nuclear Waste Policy Act of 1982 to accept and dispose of STP's spent nuclear fuel. See also *"Environmental Matters — U.S. Federal Environmental Initiatives — Nuclear Waste"* in Item 1. Costs associated with these risks could be substantial and have a material adverse effect on NRG's results of operations, financial condition or cash flow. In addition, to the extent that all or a part of STP is required by the NRC to permanently or temporarily shut down or modify its operations, or is otherwise subject to a forced outage, NRG may incur additional costs to the extent it is obligated to provide power from more expensive alternative sources — either NRG's own plants, third party generators or the ERCOT — to cover the Company's then existing forward sale obligations. Such shutdown or modification could also lead to substantial costs related to the storage and disposal of radioactive materials and spent nuclear fuel.

NRG and the other owners of STP maintain nuclear property and nuclear liability insurance coverage as required by law. The Price-Anderson Act, as amended by the Energy Policy Act of 2005, requires owners of nuclear power plants in the United States to be collectively responsible for retrospective secondary insurance premiums for liability to the public arising from nuclear incidents resulting in claims in excess of the required primary insurance coverage amount of $300 million per reactor. The Price-Anderson Act only covers nuclear liability associated with any accident in the course of operation of the nuclear reactor, transportation of nuclear fuel to the reactor site, in the storage of nuclear fuel and waste at the reactor site and the transportation of the spent nuclear fuel and nuclear waste from the nuclear reactor. All other non-nuclear liabilities are not covered. Any substantial retrospective premiums imposed under the Price-Anderson Act or losses not covered by insurance could have a material adverse effect on NRG's financial condition, results of operations or cash flows.

NRG is subject to environmental laws and regulations that impose extensive and increasingly stringent requirements on the Company's ongoing operations, as well as potentially substantial liabilities arising out of environmental contamination. These environmental requirements and liabilities could adversely impact NRG's results of operations, financial condition and cash flows.

NRG's business is subject to the environmental laws and regulations of foreign, federal, state and local authorities. The Company must comply with numerous environmental laws and regulations and obtain numerous governmental permits and approvals to operate our plants. If NRG fails to comply with any environmental requirements that apply to its operations, the Company could be subject to administrative, civil and/or criminal liability and fines, and regulatory agencies could take other actions seeking to curtail the Company's operations. In addition, when new requirements take effect or when existing environmental requirements are revised, reinterpreted or subject to changing enforcement policies, NRG's business, results of operations, financial condition and cash flows could be adversely affected.

Environmental laws and regulations have generally become more stringent over time, and the Company expects this trend to continue. In particular, several states in which NRG operates have proposed or are in the process of proposing requirements to control emissions of NOx, SO_2, and mercury from electric generating units that are more stringent than federal regulations. In Delaware, NRG and others have appealed portions of such a regulation for the control of multiple pollutants to both the Environmental Appeals Board and Delaware Superior Court, based not on the required level of emissions reductions, but on the timing for achievement of those reductions by 2009. We are unable to predict the outcome of these appeals.

There is a growing consensus in the U.S. and globally that greenhouse gases, or GHG, emissions are linked to global climate change. States in the Northeast under RGGI and California under AB32 are expected to propose rules to stabilize and reduce GHG in the near future. Increased public concern and mounting political pressure may result in more regional and/or federal requirements to reduce or mitigate the effects of GHG. NRG's U.S. generating portfolio includes coal-, oil- and gas-fired plants that are projected to emit approximately 70 million tons of CO_2, a GHG, for 2007. The Company's facilities in New York and California will be subject to regulation under RGGI and AB32, respectively. It is likely that the Company's U.S. plants would also be subject to regulation under any new GHG legislation introduced at the state, regional or national level. While NRG plans to address the risks of such GHG regulations through CO_2 offsets, by supporting CO_2 mitigation research, and by pursuing CO_2 sequestration capable facilities, technologies such as nuclear and wind that do not emit GHG, and highly efficient fossil fuel projects, the costs of complying with potential GHG regulations may be substantial and may have a significant impact on NRG's operations, cash flow and financial position. The actual impact of any state, regional or federal GHG regulations on NRG will depend on a number of factors including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are allowed, the degree to which the forward market prices on the cost of GHG regulation, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas prices.

A recent court ruling on the appeal of the USEPA Phase II 316(b) regulation has created uncertainty for power plants that use once-through cooling water. Specifically, the ruling remanded certain provisions back to the USEPA for reconsideration and prohibits certain mitigation technologies, including restoration. In light of this ruling, NRG anticipates that it will not be able to rely on restoration and cost-benefit adjustment at some of its facilities in the West region. In addition, the ruling has created some uncertainty with respect to approximately 17% of the Company's other generating units that do not have cooling towers. NRG continues to complete and analyze fish studies and design solutions which will meet the Phase II 316(b) regulation when finalized for all of its facilities that use once-through cooling. NRG is closely following progress on the final rule, although it is not possible to quantify the impact of the revisions at this time.

Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. The Company is generally responsible for all liabilities associated with the environmental condition of the Company's power generation plants, including any soil or groundwater contamination that may be present, regardless of when the liabilities arose and whether the liabilities are known or unknown, or arose from the activities of predecessors or third parties.

NRG's business, financial condition and results of operations could be adversely impacted by strikes or work stoppages by its unionized employees.

As of December 31, 2006, approximately 55% of NRG's employees at its U.S. generation plants would have been covered by collective bargaining agreements. In the event that the Company's union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, NRG would be responsible for procuring replacement labor or the Company could experience reduced power generation or outages. NRG's ability to procure such labor is uncertain. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on the Company's business, financial condition, results of operations and cash flow.

Changes in technology may impair the value of NRG's power plants.

Research and development activities are ongoing to provide alternative and more efficient technologies to produce power, including fuel cells, clean coal and coal gasification, micro-turbines, photovoltaic (solar) cells and improvements in traditional technologies and equipment, such as more efficient gas turbines. Advances in these or other technologies could reduce the costs of power production to a level below what the Company has currently forecasted, which could adversely affect its cash flow, results of operations or competitive position.

Acts of terrorism could have a material adverse effect on NRG's financial condition, results of operations and cash flows.

NRG's generation facilities and the facilities of third parties on which they rely may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of the facilities ability to generate, transmit, transport or distribute electricity or natural gas. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Any such environmental repercussions or disruption could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on the Company's financial condition, results of operations and cash flow.

NRG's international investments are subject to additional risks that its U.S. investments do not have.

NRG has investments in power projects in Australia, Germany and Brazil. International investments are subject to risks and uncertainties relating to the political, social and economic structures of the countries in which it invests. Risks specifically related to our investments in international projects may include:

- fluctuations in currency valuation;
- currency inconvertibility;
- expropriation and confiscatory taxation;
- restrictions on the repatriation of capital; and
- approval requirements and governmental policies limiting returns to foreign investors.

NRG's level of indebtedness could adversely affect its ability to raise additional capital to fund its operations, expose it to the risk of increased interest rates and limit its ability to react to changes in the economy or its industry.

NRG's substantial debt could have important consequences, including:

- increasing NRG's vulnerability to general economic and industry conditions;
- requiring a substantial portion of NRG's cash flow from operations to be dedicated to the payment of principal and interest on its indebtedness, therefore reducing NRG's ability to pay dividends to holders of its preferred or common stock or to use its cash flow to fund its operations, capital expenditures and future business opportunities;
- limiting NRG's ability to enter into long-term power sales or fuel purchases which require credit support;
- exposing NRG to the risk of increased interest rates because certain of its borrowings, including borrowings under its new senior secured credit facility are at variable rates of interest;
- limiting NRG's ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and
- limiting NRG's ability to adjust to changing market conditions and placing it at a competitive disadvantage compared to its competitors who have less debt.

The indentures for NRG's notes and senior secured credit facility contain financial and other restrictive covenants that may limit the Company's ability to engage in activities that may be in its long-term best interests.

NRG's failure to comply with those covenants could result in an event of default which, if not cured or waived, could result in the acceleration of all of the Company's indebtedness.

In addition, NRG's ability to arrange financing, either at the corporate level or at a non-recourse project-level subsidiary, and the costs of such capital, are dependent on numerous factors, including:

- general economic and capital market conditions;
- credit availability from banks and other financial institutions;
- investor confidence in NRG, its partners and the regional wholesale power markets;
- NRG's financial performance and the financial performance of its subsidiaries;
- NRG's level of indebtedness and compliance with covenants in debt agreements;
- maintenance of acceptable credit ratings;
- cash flow; and
- provisions of tax and securities laws that may impact raising capital.

NRG may not be successful in obtaining additional capital for these or other reasons. The failure to obtain additional capital from time to time may have a material adverse effect on its business and operations.

Because the historical financial information may not be representative of the results of operation as a combined company or capital structure after the Acquisition, and NRG's and Texas Genco LLC's historical financial information are not comparable to their current financial information, you have limited financial information on which to evaluate the combined company, NRG and Texas Genco LLC.

Texas Genco LLC did not exist prior to July 19, 2004, and Texas Genco LLC and its subsidiaries had no operations and no material activities until December 15, 2004 when Texas Genco LLC acquired its gas- and coal-fired assets. Consequently, Texas Genco LLC's historical financial information is not comparable to the Texas region's current financial information.

NRG and Texas Genco LLC had been operating as separate companies prior to February 2, 2006. NRG and Texas Genco LLC had no prior history as a combined company, nor have they been previously managed on a combined basis. The historical financial statements may not reflect what the combined company's results of operations, financial position and cash flows would have been had both companies operated on a combined basis and may not be indicative of what the combined company's results of operations, financial position and cash flows will be in the future.

Goodwill and/or other intangible assets not subject to amortization that NRG has recorded in connection with its acquisitions are subject to mandatory annual impairment evaluations and as a result, the Company could be required to write off some or all of this goodwill and other intangible assets, which may adversely affect the Company's financial condition and results of operations.

In accordance with Financial Accounting Standard No. 142, *Goodwill and Other Intangible Assets*, goodwill is not amortized but is reviewed annually or more frequently for impairment and other intangibles are also reviewed at least annually or more frequently, if certain conditions exist, and may be amortized. Any reduction in or impairment of the value of goodwill or other intangible assets will result in a charge against earnings which could materially adversely affect NRG's reported results of operations and financial position in future periods.

Cautionary Statement Regarding Forward Looking Information

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The words "believes", "projects", "anticipates", "plans", "expects", "intends", "estimates" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause NRG Energy, Inc.'s actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Risks Related to NRG in Item 1A of NRG's 2006 Annual Report on Form 10-K and the following:

- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that NRG may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of NRG's risk management policies and procedures, and the ability of NRG's counterparties to satisfy their financial commitments;
- Counterparties' collateral demands and other factors affecting NRG's liquidity position and financial condition;
- NRG's ability to operate its businesses efficiently, manage capital expenditures and costs tightly (including general and administrative expenses), and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;
- NRG's potential inability to enter into contracts to sell power and procure fuel on acceptable terms and prices;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Government regulation, including compliance with regulatory requirements and changes in market rules, rates, tariffs and environmental laws;
- Price mitigation strategies and other market structures employed by independent system operators, or ISO, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate NRG's generation units for all of its costs;
- NRG's ability to borrow additional funds and access capital markets, as well as NRG's substantial indebtedness and the possibility that NRG may incur additional indebtedness going forward;
- Operating and financial restrictions placed on NRG contained in the indentures governing NRG's outstanding notes in NRG's senior credit facility and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally; and
- NRG's ability to implement its *Repowering NRG* strategy of developing and building new power generation facilities, including new nuclear units and IGCC units.

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

Item 1B — *Unresolved Staff Comments*

None.

Item 2 — *Properties*

Listed below are descriptions of NRG's interests in facilities, operations and/or projects owned as of December 31, 2006. The MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units as of December 31, 2006. The following table summarizes NRG's Power Production and Cogeneration Facilities by region:

Name and Location of Facility	Purchaser/Power Market	% Owned	Net Generation Capacity	Primary Fuel-type
Texas Region:				
W. A. Parish, Thompsons, Texas	ERCOT	100.0	2,480	Coal
Limestone, Jewett, Texas	ERCOT	100.0	1,700	Lignite/Coal
South Texas Project, Bay City, Texas[(a)]	ERCOT	44.0	1,100	Nuclear
Cedar Bayou, Baytown, Texas	ERCOT	100.0	1,500	Natural Gas
T. H. Wharton, Houston, Texas	ERCOT	100.0	1,025	Natural Gas
W. A. Parish, Thompsons, Texas	ERCOT	100.0	1,190	Natural Gas
S. R. Bertron, Deer Park, Texas	ERCOT	100.0	840	Natural Gas
Greens Bayou, Houston, Texas	ERCOT	100.0	760	Natural Gas
San Jacinto, LaPorte, Texas	ERCOT	100.0	165	Natural Gas
Northeast Region:				
Oswego, New York	NYISO	100.0	1,635	Oil
Arthur Kill, Staten Island, New York	NYISO	100.0	865	Natural Gas
Middletown, Connecticut	ISO-NE	100.0	770	Oil
Indian River, Millsboro, Delaware	PJM	100.0	780	Coal
Astoria Gas Turbines, Queens, New York	NYISO	100.0	550	Natural Gas
Dunkirk, New York	NYISO	100.0	585	Coal
Huntley, Tonawanda, New York	NYISO	100.0	550	Coal
Montville, Uncasville, Connecticut	ISO-NE	100.0	500	Oil
Norwalk Harbor, So. Norwalk, Connecticut	ISO-NE	100.0	340	Oil
Devon, Milford, Connecticut	ISO-NE	100.0	140	Natural Gas
Vienna, Maryland	PJM	100.0	170	Oil
Somerset, Massachusetts	ISO-NE	100.0	125	Coal
Connecticut Jet Power, Connecticut (four sites)	ISO-NE	100.0	105	Oil
Conemaugh, New Florence, Pennsylvania	PJM	3.7	65	Coal
Keystone, Shelocta, Pennsylvania	PJM	3.7	60	Coal

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Name and Location of Facility	Purchaser/Power Market	% Owned	Net Generation Capacity	Primary Fuel-type
South Central Region:				
Big Cajun II, New Roads, Louisiana(b)	SERC-Entergy	86.0	1,490	Coal
Bayou Cove, Jennings, Louisiana	SERC-Entergy	100.0	300	Natural Gas
Big Cajun I, Jarreau, Louisiana	SERC-Entergy	100.0	210	Natural Gas
Big Cajun I, Jarreau, Louisiana	SERC-Entergy	100.0	220	Natural Gas/Oil
Rockford I, Illinois	PJM	100.0	300	Natural Gas
Rockford II, Illinois	PJM	100.0	145	Natural Gas
Sterlington, Louisiana	SERC-Entergy	100.0	185	Natural Gas
West Region:				
Encina, Carlsbad, California	Cal ISO	100.0	965	Natural Gas
El Segundo Power, California	Cal ISO	100.0	670	Natural Gas
San Diego Combustion Turbines, California (three sites)	Cal ISO	100.0	190	Natural Gas
Chowchilla, California(c)	Cal ISO	100.0	50	Natural Gas
Red Bluff, California(c)	Cal ISO	100.0	45	Natural Gas
Saguaro Power Co., Henderson, Nevada	WECC	50.0	45	Natural Gas
International Region				
Gladstone Power Station, Queensland, Australia	Enertrade/Boyne Smelters	37.5	605	Coal
Schkopau Power Station, Germany	Vattenfall Europe	41.9	400	Lignite
MIBRAG, Germany(d)	ENVIA/MIBRAG Mines	50.0	75	Lignite
ITISA, Brazil	COPEL	99.2	155	Hydro
Corporate				
Power Smith Cogeneration, Oklahoma City, Oklahoma	SPP	6.25	7	Natural Gas

(a) For the nature of NRG's interest and various limitations on the Company's interest, please read Item 1 — Business — Texas — Generation Facilities section.

(b) Units 1 and 2 owned 100.0%, Unit 3 owned 58.0%

(c) Sold January 2, 2007

(d) Primarily a coal mining facility

The following table summarizes NRG's thermal facilities as of December 31, 2006:

Name and Location of Facility	Thermal Energy Purchaser	% Ownership Interest	Generating Capacity(a)
NRG Energy Center Minneapolis, MN	Approx. 100 steam customers and 47 chilled water customers	100.0	Steam: 1,203 MMBtu/hr. (353 MWt) Chilled Water: 42,630 tons (150 MWt)
NRG Energy Center San Francisco, CA	Approx. 175 steam customers	100.0	Steam: 482 MMBtu/Hr. (141 MWt)
NRG Energy Center Harrisburg, PA	Approx. 250 steam customers and 3 chilled water customers	100.0	Steam: 440 MMBtu/hr. (129 MWt) Chilled water: 2,400 tons (8 MWt)
NRG Energy Center Pittsburgh, PA	Approx. 25 steam and 25 chilled water customers	100.0	Steam: 266 MMBtu/hr. (78 MWt) Chilled water: 12,920 tons (45 MWt)
NRG Energy Center San Diego, CA	Approx. 20 chilled water customers	100.0	Chilled water: 7,425 tons (26 MWt)
NRG Energy Center St. Paul, MN	Rock-Tenn Company	100.0	Steam: 430 MMBtu/hr. (126 MWt)
Camas Power Boiler, Camas, WA	Georgia-Pacific Corp.	100.0	Steam: 200 MMBtu/hr. (59 MWt)
NRG Energy Center Dover, DE	Kraft Foods Inc.	100.0	Steam: 190 MMBtu/hr. (56 MWt)
NRG Energy Center Oak Park Heights, MN	Anderson Corp., MN Correctional Facility	100.0	Steam: 200 MMBtu/Hr. (59 MWt)
Paxton Creek Cogeneration, Harrisburg, PA	PJM	100.0	12 MW — Natural Gas
Dover, DE	PJM	100.0	106 MW — Natural Gas/Coal

Other Properties

In addition, NRG owns various real property and facilities relating to its generation assets, other vacant real property unrelated to our generation assets, interest in a construction project, and properties not used for operational purposes. NRG believes it has satisfactory title to its plants and facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in the Company's opinion, would not have a material adverse effect on the use or value of its portfolio.

NRG leases its corporate offices at 211 Carnegie Center, Princeton, New Jersey 08540 and various other office spaces.

Item 3 — ***Legal Proceedings***

In re: Wholesale Electricity Antitrust Litigation, Judicial Council Coordinated Proceeding No. 4204, or JCCP 4204, Superior court of California, San Diego County (formerly MDL 1405, U.S. District Court, Southern District of California). The cases included in this proceeding are as follows:

> ***Pamela R Gordon, on Behalf of Herself and All Others Similarly Situated v Reliant Energy, Inc. et al.,*** **Case No. 758487, Superior Court of the State of California, County of San Diego** *(filed on November 27, 2000).* ***Ruth Hendricks, On Behalf of Herself and All Others Similarly Situated and On Behalf of the General Public v. Dynegy Power Marketing, Inc. et al.,*** **Case No. 758565, Superior Court of the State of California, County of San Diego** *(filed November 29, 2000).* ***The People of the State of California, by and through San Francisco City Attorney Louise H. Renne v. Dynegy Power Marketing, Inc. et al.,*** **Case No. 318189, Superior Court of California, San Francisco County** *(filed January 18, 2001).* ***Pier 23 Restaurant, A California Partnership, On Behalf of Itself and All Others Similarly Situated v PG&E Energy Trading et al.,*** **Case No. 318343, Superior Court of California, San Francisco County** *(filed January 24, 2001).* ***Sweetwater Authority, et al. v. Dynegy, Inc. et al.,*** **Case No. 760743, Superior Court of California, County of San Diego** *(filed January 16, 2001).* ***Cruz M Bustamante, individually, and Barbara Matthews, individually, and on behalf of the general public and as a representative taxpayer suit, v. Dynegy Inc. et al., inclusive.*** **Case No. BC249705, Superior Court of California, Los Angeles County** *(filed May 2, 2001).*

NRG was dismissed from the JCCP 4204 proceeding on July 22, 2005. On May 17, 2006, the U.S. Bankruptcy Court for the Southern District of New York granted NRG's motion to disallow all pre-petition claims filed against NRG related to the California energy crisis in 2000 and 2001. Plaintiffs did not appeal this decision. Several of WCP's operating subsidiaries remain defendants in cases that are part of the JCCP 4204 proceeding. The cases in the proceeding allege unfair competition, market manipulation and price fixing and all seek treble damages, restitution and injunctive relief. The defendants, including the WCP subsidiaries, filed a motion to dismiss based on the filed rate doctrine and federal preemption which was granted on October 3, 2005, and a judgment of dismissal with prejudice was entered on October 5, 2005. Plaintiffs filed a notice of appeal on December 2, 2005, with the California Court of Appeals — Fourth District and on February 26, 2007, the court affirmed the lower court's judgment of dismissal relying on the filed rate doctrine and federal preemption. Where WCP or its subsidiaries are named, Dynegy is defending them pursuant to an indemnification agreement.

Bustamante v. McGraw-Hill Companies, Inc., et al., **No. BC 235598, California Superior Court, Los Angeles County** *(filed November 20, 2002, and amended in 2003)* **—** This putative class action alleges that the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades. Named defendants in the suit include several of WCP's operating subsidiaries. The complaint seeks restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Defendants' motion for summary judgment is pending. Dynegy is defending the WCP subsidiaries pursuant to an indemnification agreement.

Texas-Ohio Energy, Inc., on behalf of Itself and all others similarly situated v. Dynegy, Inc. Holding Co., West Coast Power, LLC, et al., **Case No. CIV.S-03-2346 DFL GGH, U.S. District Court, Eastern District of California** *(filed November 10, 2003)* **—** This putative class action alleges violations of the federal Sherman and Clayton Acts and state antitrust law. In addition to naming WCP and Dynegy, Inc. Holding Co., the complaint names numerous industry participants, as well as "unnamed co-conspirators." The complaint alleges that defendants conspired to manipulate the spot price and basis differential of natural gas with respect to the California market. The complaint seeks unspecified amounts of damages, including a trebling of plaintiff's and the putative class's actual damages. On April 18, 2005, the court granted defendants' motion to dismiss based on the filed rate doctrine and federal preemption. On May 17, 2005, Plaintiffs filed a notice of appeal with the U.S. Court of Appeals for the Ninth Circuit. Dynegy is defending WCP pursuant to an indemnification agreement.

City of Tacoma, Department of Public Utilities, Light Division, v. American Electric Power Service Corporation, et al., **U.S. District Court, Western District of Washington, Case No. C04-5325 RBL** *(filed June 16, 2004)* **—** The complaint names over 50 defendants, including WCP's four operating subsidiaries and various Dynegy entities. The complaint also names both us and WCP as "Non-Defendant Co-Conspirators." Plaintiff alleges a conspiracy to violate the federal Sherman Act by withholding power generation from, and/or inflating the apparent demand for power in markets in California and elsewhere. Plaintiff claims damages in excess of $175 million. After the case was transferred to the U.S. District Court for the Southern District of California on

February 11, 2005, the court granted defendants' motion to dismiss the case based on the filed rate doctrine and federal preemption. On March 21, 2005, Plaintiffs filed a notice of appeal with the U.S. Court of Appeals for the Ninth Circuit. Dynegy is defending WCP and its subsidiaries pursuant to an indemnification agreement.

Fairhaven Power Company v. Encana Corporation, et al., Case No. CIV-F-04-6256 (OWW/ LJO), U.S. District Court, Eastern District of California *(filed September 22, 2004),* ***Abelman v. Encana, U.S.*** **District Court, Eastern District of California, Case No. 04-CV-6684** *(filed December 13, 2004)*; ***Utility Savings v. Reliant, et al.,*** **U.S. District Court, Eastern District of California,** *(filed November 29, 2004)* **—** These putative class actions named WCP and Dynegy Holding Co., Inc. among the numerous defendants. The Complaints alleged violations of the federal Sherman Act, and California's antitrust and unfair competition law as well as unjust enrichment. The Complaints sought a determination of class action status, a trebling of unspecified damages, statutory, punitive or exemplary damages, restitution, disgorgement, injunctive relief, a constructive trust, and costs and attorneys' fees. On December 19, 2005, the court granted defendants notice to dismiss based upon the filed rate doctrine and federal preemption. Dynegy is defending WCP pursuant to an indemnification agreement. On February 2, 2006, Dynegy settled the case on behalf of itself and WCP and Plaintiffs are expected to file a motion to approve the settlement with the Court by the end of the first quarter 2007. If approved, WCP will pay no defense costs or settlement funds, as Dynegy owed and provided a complete defense and indemnification.

Natural Gas Anti-Trust Cases I,II,III & IV, **California Judicial Council Coordination Proceeding Nos. 4221, 4224, 4226 and 4228, San Diego County Superior Court, California.** The cases consolidated in this proceeding are as follows:

ABAG Publicly Owned Energy Resources v. Sempra Energy, et al., **Alameda County Superior Court, Case No. RG04186098,** *(filed November 10, 2004)*; ***Cruz Bustamante v. Williams Energy Services, et al.,*** **Los Angeles Superior Court, Case No. BC285598,** *(filed June 28, 2004)*; ***City & County of San Francisco, et al. v. Sempra Energy, et al.*****, San Diego County Superior Court, Case No. GIC832539,** *(filed June 8, 2004)*; ***City of San Diego v. Sempra Energy, et al.,*** **San Diego County Superior Court, Case No. GIC839407,** *(filed December 1, 2004)*; ***County of Alameda v. Sempra Energy,*** **Alameda County Superior Court, Case No. RG041282878,** *(filed October 29, 2004)*; ***County of San Diego v. Sempra Energy, et al.,*** **San Diego County Superior Court, Case No. GIC833371,** *(filed July 28, 2004)*; ***County of San Mateo v. Sempra Energy, et al.,*** **San Mateo County Superior Court, Case No. CIV443882,** *(filed December 23, 2004)*; ***County of Santa Clara v. Sempra Energy, et al.,*** **San Diego County Superior Court, Case No. GIC832538,** *(filed July 8, 2004)*; ***Nurserymen's Exchange, Inc. v. Sempra Energy, et al.,*** **San Mateo County Superior Court, Case No. CIV442605,** *(filed October 21, 2004)*; ***Older v. Sempra Energy, et al.,*** **San Diego Superior Court, Case No. GIC835457,** *(filed December 8, 2004)*; ***Owens-Brockway Glass Container, Inc. v. Sempra Energy, et al.,*** **Alameda County Superior Court, Case No. RG0412046**, *(filed December 30, 2004)*; ***Sacramento Municipal Utility District v. Reliant Energy Services, Inc.,*** **Sacramento County Superior Court, Case No. 04AS04689**, *(filed November 19, 2004)*; ***School Project for Utility Rate Reduction v. Sempra Energy, et al.,*** **Alameda County Superior Court, Case No. RG04180958,** *(filed October 19, 2004)*; ***Tamco, et al. v. Dynegy, Inc., et al.,*** **San Diego County Superior Court, Case No. GIC840587,** *(filed December 29, 2004)*; ***Utility Savings & Refund Services, LLP v. Reliant Energy Services, Inc., et al.,*** **U.S. District Court, Eastern District of California, Case No. 04-6626,** *(filed November 30, 2004)*; ***Pabco Building Products v. Dynegy et al.,*** **San Diego Superior Court, Case No. GIC 856187,** *(filed November 22, 2005)*; ***The Board of Trustees of California State University v. Dynegy et al.,*** **San Diego Superior Court, Case No. GIC 856188,** *(filed November 22, 2005).*

The defendants in all of the above referenced cases include WCP and various Dynegy entities. NRG is not a defendant. The Complaints allege that defendants attempted to manipulate natural gas prices in California, and allege violations of California's antitrust law, conspiracy, and unjust enrichment. The relief sought in all of these cases includes treble damages, restitution and injunctive relief. The Complaints assert that WCP is a joint venture between Dynegy and NRG, but that Dynegy Marketing and Trade handled all of the administrative services and commodity related concerns of WCP. Defendants' motion to dismiss was denied by the Court on June 22, 2005, and the cases are in discovery. Dynegy entered into a settlement agreement with Plaintiffs on behalf of itself and WCP in the ***Older*** case and the court approved the settlement on December 11, 2006. WCP paid no defense costs or settlement funds, as Dynegy owed and provided a complete defense and indemnification. In the other cases in this proceedings, Dynegy is defending WCP pursuant to an indemnification agreement.

California Electricity and Related Litigation Indemnification **—** In the above cases relating to natural gas, Dynegy's counsel is defending WCP and/or its subsidiaries and will be the responsible party for any loss. In the above cases relating to electricity, Dynegy's counsel is representing it and WCP and/or its subsidiaries with Dynegy and WCP each responsible for half of the costs and each party responsible for half of any loss. Any new cases filed within these categories of cases would be handled in the same manner.

Public Utilities Commission of the State of California et al. v. Federal Energy Regulatory Commission, **Nos. 03-74246 and 03-74207, FERC Nos. EL 02-60-000, EL 02-60, and EL 02-62** *(filed December 19, 2006)* **—** The U.S. Court of Appeals for the Ninth Circuit reversed FERC and remanded the case to FERC for further proceedings consistent with the decision. This matter concerns, among other contracts and other defendants, the California Department of Water Resources, or CDWR, and its wholesale power contract with subsidiaries of WCP. The case originated with a February 2002 complaint filed by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. With respect to WCP, the complaint demanded that FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, FERC rejected this demand, denied rehearing, and the case was appealed to the Ninth Circuit where oral argument was held December 8, 2004. The Ninth Circuit held that in FERC's review of the contracts at issue, FERC could not rely on the Mobile-Sierra standard presumption of just and reasonable rates, as such contracts were not reviewed by FERC with full knowledge of the then-existing market conditions. None of the dependents sought rehearing by the Ninth Circuit within the requested time period. Because an extension of time will be filed shortly, WCP and the other defendants will have until April 18, 2007, to seek review by the U.S. Supreme Court or they can instead wait for the case to be remanded back to FERC. If review before the U.S. Supreme Court is sought, the Court will decide in 2007 whether it will accept the appeal. At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG's financial condition, results of operations, and statement of cash flows. As part of the 2006 acquisition of Dynegy's share of the WCP assets, WCP and NRG assumed responsibility for any risk of loss arising from this case unless any such loss is deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally by WCP and Dynegy.

Connecticut Light & Power Company v. NRG Power Marketing, Inc., **Docket No. 3:01-CV-2373 (AWT), U.S. District Court, District of Connecticut** *(filed on November 28, 2001)* **—** Connecticut Light & Power Company, or CL&P, sought recovery of amounts it claimed it was owed for congestion charges under the terms of an October 29, 1999, contract between the parties. CL&P withheld approximately $30 million from amounts owed to NRG Power Marketing, Inc., or PMI, and PMI counterclaimed. CL&P filed its motion for summary judgment to which PMI filed a response on March 21, 2003. By reason of the stay issued by the bankruptcy court, the court has not ruled on the pending motion. On November 6, 2003, the parties filed a joint stipulation for relief from the stay in order to allow the proceeding to go forward, which was promptly granted. PMI cannot estimate at this time the overall exposure for congestion charges for the full term of the contract.

Connecticut Light & Power Company v. NRG Energy, Inc., **Federal Energy Regulatory Commission Docket No. EL03-10-000-Station Service Dispute** *(filed October 9, 2002);* **Binding Arbitration —** On July 1, 1999, Connecticut Light & Power Company, or CL&P, and the Company agreed that we would purchase certain CL&P generating facilities. The transaction closed on December 14, 1999, whereupon NRG took ownership of the facilities. CL&P began billing NRG for station service power and delivery services provided to the facilities and NRG refused to pay, asserting that the facilities self-supplied their station service needs. On October 9, 2002, Northeast Utilities Services Company, on behalf of itself and CL&P, filed a complaint at FERC seeking an order requiring NRG Energy to pay for station service and delivery services. On December 20, 2002, 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. CL&P renewed its demand for payment which was again refused by NRG. In August 2003, the parties agreed to submit the dispute to binding arbitration. In July and August 2006, the parties submitted their respective statements to the three member arbitration panel. A discovery and briefing schedule was issued and a hearing is set for September 2007.

Niagara Mohawk Power Corporation v. Dunkirk Power LLC, NRG Dunkirk Operations, Inc., Huntley Power LLC, NRG Huntley Operations, Inc., Oswego Power LLC and NRG Oswego Operations, Inc., **Supreme Court, Erie County, Index No. 1-2000-8681 — Station Service Dispute** *(filed October 2, 2000)* **—** NiMo sought to recover damages less payments received through the date of judgment, as well as additional amounts for electric service provided to the Dunkirk Plant. NiMo claimed that we failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999, and continuing to September 18, 2000, and thereafter. On October 8, 2002, a Stipulation and Order was entered, staying this action pending resolution by FERC of the disputes in this matter.

Niagara Mohawk Power Corporation v. Huntley Power LLC, NRG Huntley Operations, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power LLC, Oswego Harbor Power LLC, and NRG Oswego Operations, Inc., *(Filed November 26, 2002)* **in Federal Energy Regulatory Commission Docket No. EL 03-27-000 —** This is the companion action to the above referenced action filed by NiMo at FERC asserting the same claims and legal theories. On November 19, 2004, FERC denied NiMo's petition and ruled that the Huntley, Dunkirk and Oswego plants could net their service station obligations over a 30 calendar day period from the day NRG Energy 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 and on October 23, 2006, the U.S. Court of Appeals for the D.C. Circuit denied rehearing. On January 22, 2007, NiMo filed a petition for certiorari seeking review before the U.S. Supreme Court.

***CFTC Trading Litigation* —** On July 1, 2004, the Commodities Futures Trading Commission, or CFTC, filed a civil complaint against us 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. On March 16, 2005, the federal district court in Minnesota dismissed the case. On appeal, the U.S. Court of Appeals in August 2006 reversed the district court's dismissal. The parties have agreed to a settlement in which NRG agreed to give the CFTC a $2 million allowed class 5 claim in NRG's bankruptcy proceeding. The settlement agreement was approved by the Court on February 13, 2007.

***Additional Litigation* —** In addition to the foregoing, NRG is party to other litigation or legal proceedings. The Company believes that it has valid defenses to the legal proceedings and investigations described above 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 above, the Company is unable to predict the outcome 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.

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

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company's Chapter 11 plan totaling $25 million in cash and 2,541,000 shares of common stock. As of January 24, 2007, the reserve held approximately $9.9 million in cash and approximately 691,700 shares of common stock. NRG believes the cash and stock together represent sufficient funds to satisfy all remaining disputed claims.

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

None.

PART II

Item 5 — *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market Information and Holders

NRG's authorized capital stock consists of 500,000,000 shares of NRG common stock and 10,000,000 shares of preferred stock. A total of 8,000,000 shares of the Company's common stock are available for issuance under NRG's Long-Term Incentive Plan. NRG has also filed with the Secretary of State of Delaware a Certificate of Designation for each of the following shares of the Company's preferred stock: (i) 4% Convertible Perpetual Preferred Stock, (ii) 3.625% Convertible Perpetual Preferred Stock, and (iii) 5.75% Mandatory Convertible Preferred Stock.

NRG's common stock is listed on the New York Stock Exchange and has been assigned the symbol: NRG. NRG has submitted to the New York Stock Exchange its annual certificate from its Chief Executive Officer certifying that he is not aware of any violation by the Company of New York Stock Exchange corporate governance listing standards. The high and low sales prices, as well as the closing price for the Company's common stock on a per share basis for 2006 and 2005 are set forth below:

Common Stock Price	Fourth Quarter 2006	Third Quarter 2006	Second Quarter 2006	First Quarter 2006	Fourth Quarter 2005	Third Quarter 2005	Second Quarter 2005	First Quarter 2005
High	$ 59.48	$ 51.15	$ 52.61	$ 49.46	$ 49.44	$ 44.45	$ 37.61	$ 39.10
Low	$ 44.27	$ 44.25	$ 42.44	$ 41.79	$ 37.60	$ 36.40	$ 30.30	$ 32.79
Closing	$ 56.01	$ 45.30	$ 48.18	$ 45.22	$ 47.12	$ 42.60	$ 37.60	$ 34.15

NRG had 122,323,551 shares outstanding as of December 31, 2006, and as of February 23, 2007, there were 122,335,466 shares outstanding. As of February 22, 2007, there were approximately 36,500 common stockholders of record.

Dividends

NRG has not declared or paid dividends on its common stock and the amount available for dividends is currently limited by the Company's senior secured credit agreements and high yield note indentures.

Repurchase of equity securities

NRG's repurchases of equity securities during 2006 were as follows:

For the Year Ended December 31, 2006	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Dollar Value of Shares That May be Purchased Under the Plans or Programs
First quarter	—	—	—	—
Second quarter	—	—	—	—
July 1 – July 31	—	—	—	—
August 1 – August 31	—	—	—	$ 500,000,000
September 1 – September 30	6,113,000	$ 48.61	6,113,000	202,847,070
Third quarter total	6,113,000	48.61	6,113,000	—
October 1 – October 31	4,474,700	45.32	4,474,700	500,053,666
November 1 – November 30	4,212,881	55.00	4,212,881	268,345,211
December 1 – December 31	—	—	—	—
Fourth quarter total	8,687,581	50.01	8,687,581	268,345,211
Total for 2006	14,800,581	$ 49.43	14,800,581	$ 268,345,211

During the third quarter 2006, as part of the Company's Capital Allocation Program, NRG repurchased approximately $750 million of the Company's common stock in two phases. Phase I was a $500 million stock repurchase program, which was completed on October 13, 2006, with total common stock repurchased of 10,587,700 shares.

Phase II, as originally announced, was to be an additional $250 million common stock buyback. This amount was subsequently increased to $500 million and Phase II commenced during the fourth quarter 2006, bringing the Company's total announced share buyback to $1 billion. On November 24, 2006, NRG repurchased 4,212,881 shares of NRG common stock from affiliates of the Blackstone Group at a price of $55.00 per share as part of Phase II. Following this repurchase, the four largest previous shareholders of Texas Genco LLC have concluded the sale of all of their NRG common stock received pursuant to the Acquisition. We expect to complete Phase II during the first half of 2007.

Securities Authorized for Issuance under Equity Compensation Plans

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Compensation Plans (Excluding Securities Reflected in Column (a)
Equity compensation plans approved by security holders	3,395,413	$ 24.22	4,301,489(a)
Equity compensation plans not approved by security holders	—	N/A	—
Total	3,395,413	$ 24.22	4,301,489(a)

(a) NRG Energy, Inc.'s Long-Term Incentive Plan, or the LTIP, became effective upon the Company's emergence from bankruptcy. The LTIP was subsequently approved by the Company's stockholders on August 4, 2004 and was amended on April 28, 2006 to increase the number of shares available for issuance to 8,000,000 and again on December 8, 2006 to make technical and administrative changes. The LTIP provides for grants of stock options, stock appreciation rights, restricted stock, performance units, deferred stock units and dividend equivalent rights.

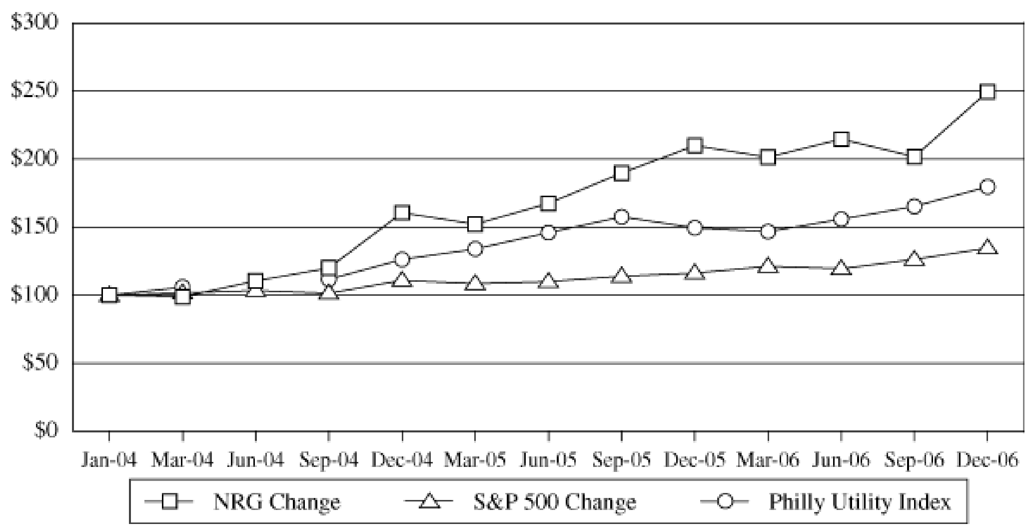
NRG's directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by the Company, are eligible to receive grants under the LTIP. The purpose of the LTIP is to promote the Company's long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to the Company's success and to enable the Company to attract, retain and reward the best available persons for positions of responsibility. The Compensation Committee of the Board of Directors administers the LTIP. There were 4,301,489 and 1,355,193 shares of common stock remaining available for grants of awards under NRG's LTIP as of December 31, 2006 and 2005, respectively.

Stock Performance Graph

The performance graph below compares NRG's cumulative total shareholder return on the Company's common stock for the period January 2, 2004 through December 31, 2006 with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, or S&P 500, and the Philadelphia Utility Sector Index, or UTY. Upon the Company's emergence from bankruptcy on December 5, 2003 until March 24, 2004, NRG's common stock traded on the Over-The-Counter Bulletin Board. On March 25, 2004, NRG's common stock commenced trading on the New York Stock Exchange under the symbol "NRG".

The performance graph shown below is being provided as furnished and compares each period assuming that $100 was invested on January 2, 2004 in each of the common stock of NRG, the stocks included in the S&P 500 and the stocks included in the UTY, and that all dividends were reinvested.

Comparison of Cumulative Total Return



	1/04	3/04	6/04	9/04	12/04	3/05	6/05	9/05	12/05	3/06	6/06	9/06	12/06
NRG	$100	$98.89	$ 110.47	$ 120.00	$160.58	$ 152.12	$167.48	$189.76	$209.89	$201.43	$ 214.61	$201.78	$249.49
S&P 500	100	101.69	103.44	101.50	110.88	108.50	109.98	113.95	116.33	121.22	119.48	126.25	134.70
UTY	$100	$105.95	$104. 20	$111.74	$126.23	$133.97	$ 145.94	$ 157.53	$ 149.50	$146.70	$155.86	$165.24	$ 179.67

Item 6 — *Selected Financial Data*

The following table presents NRG's historical selected financial data. The data included in the following table has been restated to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations. For additional information refer to Item 15 — Note 4, *Discontinued Operations*, to the Consolidated Financial Statements.

This historical data should be read in conjunction with the Consolidated Financial Statements and the related notes thereto in Item 15 and Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.* Due to the adoption of Fresh Start reporting as of December 5, 2003, Reorganized NRG's balance sheet and statement of operations have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start reporting.

	Reorganized NRG				Predecessor Company	
	Year Ended December 31,			December 6 - December 31,	January 1 - December 5,	Year Ended December 31,
	2006	2005	2004	2003	2003	2002
	(In millions except ratio and per share data)					
Statement of income data:						
Total operating revenues	$5,623	$ 2,430	$ 2,104	$ 121	$ 1,589	$ 1,688
Total operating costs and expenses	4,743	2,311	1,875	110	(1,603)	4,544
Income/(loss) from continuing operations, net	555	72	155	12	3,131	(2,697)
Income/(loss) from discontinued operations, net	66	12	31	(1)	(365)	(767)
Net income/(loss)	621	84	186	11	2,766	(3,464)
Common share data:						
Basic shares outstanding — average	129	85	100	100		
Diluted shares outstanding — average	150	85	100	100		
Shares outstanding — end of year	122	81	87	100		
Per share data:						
Income from continuing operations — basic	3.90	0.61	1.55	0.12		
Income from continuing operations — diluted	3.63	0.61	1.54	0.12		
Net income — basic	4.41	0.76	1.86	0.11		
Net income — diluted	4.07	0.75	1.85	0.11		
Book value	38.96	22.61	26.26	24.37		

	Reorganized NRG				Predecessor Company	
	Year Ended December 31,			December 6 - December 31,	January 1 - December 5,	Year Ended December 31,
	2006	2005	2004	2003	2003	2002
	(In millions except ratio and per share data)					
Business metrics:						
Cash flow from operations	408	68	645	(589)	238	430
Liquidity position	$ 2,227	$ 758	$ 1,600	$ 1,545	N/A	N/A
Ratio of earnings to fixed charges	2.38	1.56	1.88	1.71	11.61	(5.17)
Ratio of earnings to fixed charges and preference dividends	2.10	1.33	1.88	1.71	11.61	(5.17)
Return on equity	10.98	3.77	6.91	N/A	N/A	N/A
Ratio of debt to total capitalization	57.48	44.82	44.99	56.09	N/A	N/A
Balance sheet data:						
Current assets	$ 3,083	$2,196	$ 2,121	$ 2,186	N/A	$ 1,584
Current liabilities	2,032	1,357	1,091	2,098	N/A	9,865
Property, plant and equipment, net	11,600	2,609	2,685	3,315	N/A	5,196
Total assets	19,435	7,466	7,873	9,320	N/A	10,964
Long-term debt, including current maturities and capitol leases	8,777	2,505	3,271	3,648	N/A	7,117
Total stockholders' equity/(deficit)	$ 5,658	$ 2,231	$2,692	$ 2,437	N/A	$ (696)

N/A not applicable

The following table provides the details of NRG's operating revenues:

	Reorganized NRG				Predecessor Company	
	Year Ended December 31,			December 6 - December 31,	January 1 - December 5,	Year Ended December 31,
	2006	2005	2004	2003	2003	2002
				(In millions)		
Energy	$ 3,193	$1,870	$1,205	$ 53	$ 788	$ 1,028
Capacity	1,516	563	612	37	566	553
Risk management activities	124	(292)	61	—	19	7
Contract amortization	628	9	(6)	13	—	—
Thermal	124	124	112	9	24	30
Hedge Reset	(129)	—	—	—	—	—
Other	167	156	120	9	192	70
Total operating revenues	$ 5,623	$ 2,430	$ 2,104	$ 121	$ 1,589	$ 1,688

Energy revenue consists of revenues received from third parties for sales in the day-ahead and real-time markets, as well as bilateral sales. Beginning in 2006, energy revenues also included revenues from the settlement of financial instruments that qualify for cash flow hedge accounting treatment.

Capacity revenue consists of revenues received from a third party at either the market or negotiated contract rates for making installed generation capacity available in order to satisfy system integrity and reliability requirements. In addition, capacity revenue includes revenue received under tolling arrangements, which entitle third parties to dispatch NRG's facilities and assume title to the electrical generation produced from that facility.

Risk management activities are comprised of fair value changes of financial instruments that have yet to be settled as well as ineffectiveness on financial transactions accorded cash flow hedge accounting treatment. It also includes the settlement of all derivative transactions that do not qualify for cash flow hedge accounting treatment. Prior to 2006, risk management activities included the settlement of financial instruments that qualified for cash flow hedge accounting treatment.

Thermal revenue consists of revenues received from the sale of steam, hot and chilled water generally produced at a central district energy plant and sold to commercial, governmental and residential buildings for space heating, domestic hot water heating and air conditioning. It also includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process.

Contract amortization revenues consists of acquired power contracts, gas swaps, and certain power sales agreements assumed at Fresh Start related to the sale of electric capacity and energy in future periods, which are amortized into revenue over the term of the underlying contracts based on actual generation or contracted volumes.

Hedge Reset is the impact from the net settlement of long-term power contracts and gas swaps by negotiating prices to current market. This transaction was completed in November 2006.

Other revenue primarily consists of operations and maintenance fees, O&M fees, sale of natural gas and emission allowances, and revenue from ancillary services. O&M fees consist of revenues received from providing certain unconsolidated affiliates with services under long-term operating agreements. Ancillary services are comprised of the sale of energy-related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products.

Item 7 — *Management's Discussion and Analysis of Financial Condition and Results of Operations*

In this discussion and analysis, the Company discusses and explains the financial condition and the results of operations for NRG during 2006 that will include the points below:

- Factors which affect NRG's business;
- NRG's earnings and costs in the periods presented;
- Changes in earnings and costs between periods;
- Impact of these factors on NRG's overall financial condition;
- A discussion of known trends that may affect NRG's future results of operations and financial condition;
- Expected future expenditures for capital projects; and
- Expected sources of cash for future operations and capital expenditures.

As you read this discussion and analysis, refer to NRG's Consolidated Statements of Operations, which present the results of the Company's operations for the years ended December 31, 2006, 2005 and 2004. The Company analyzes and explains the differences between the periods in the specific line items of NRG's Consolidated Statements of Operations. This discussion and analysis has been organized as follows:

- Business strategy;
- Business environment in which NRG operates including how regulation, weather, and other factors affect the business;
- Significant events that are important to understanding the results of operations and financial condition;
- Results of operations including an overview of the Company's results, followed by a more detailed review of those results by operating segment;
- Financial condition addressing its credit ratings, sources and uses of cash, capital resources and requirements, commitments, and off-balance sheet arrangements;
- Known trends that will affect NRG's results of operations in the future; and
- Critical accounting policies which are most important to both the portrayal of the Company's financial condition and results of operations, and which require management's most difficult, subjective or complex judgment.

Executive Summary

Overview

NRG Energy, Inc., NRG, or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is primarily engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and internationally. As of December 31, 2006, NRG had a total global portfolio of 223 active operating generation units at 51 power generation plants, with an aggregate generation capacity of approximately 24,175 MW. Within the United States, the Company has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,940 MW of generation capacity in 207 active generating units at 45 plants. These power generation facilities are primarily located in Texas, (approximately 10,760 MW), and the Northeast (approximately 7,240 MW), South Central (approximately 2,850 MW) and the West (approximately 1,965 MW) regions of the United States, with approximately 125 MW from the Company's thermal assets. NRG's principal domestic power plants consist of a diversified mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 45%, 34%, 16% and 5% of the Company's total domestic generation capacity, respectively. In addition, 15% of NRG's domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option, and consist primarily of baseload, intermediate and peaking power generation facilities, which are referred to as the merit order, and also include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company's revenues and provides a stable source of cash flow. In addition, NRG's diverse generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability. In addition, NRG is pursuing opportunities to repower existing facilities and develop new generation capacity in markets in which NRG currently owns assets in an initiative referred to as *Repowering NRG.* In connection with NRG's acquisition of Padoma Wind Power LLC, the Company has and will continue to actively evaluate and potentially develop or construct domestic terrestrial wind projects as part of the *Repowering NRG* program.

Business Strategy

NRG's strategy is to optimize the value of the Company's generation assets while using that asset base as a platform for growth and enhanced financial performance which can be sustained and expanded upon in the years to come. NRG plans to maintain and enhance the Company's position as a leading wholesale power generation company in the United States in a cost-effective and risk-mitigating manner in order to serve the bulk power requirements of NRG's existing customer base and other entities that offer load or otherwise consume wholesale electricity products and services in bulk. NRG's strategy includes the following elements:

Pursue additional growth opportunities at existing sites — NRG is favorably positioned to pursue growth opportunities through expansion of its existing generating capacity and development of new generating capacity at its existing facilities. NRG intends to invest in the Company's existing assets through plant improvements, repowerings, brownfield development and site expansions to meet anticipated requirements for additional capacity in NRG's core markets. In furtherance of this goal, NRG has initiated a company-wide program, known as *Repowering NRG*, to develop, construct and operate new and enhanced power generation facilities at its existing sites, with an emphasis on new baseload capacity that is supported by long-term power sales agreements and financed with limited or non-recourse project financing. NRG expects that these efforts will provide one or more of the following benefits: improved heat rates; lower delivered costs; expanded electricity production capability; an improved ability to dispatch economically across the merit order; increased technological and fuel diversity; and reduced environmental impacts, including facilities that either have zero greenhouse gas emissions or can be equipped to capture and, eventually, sequester greenhouse gas emissions.

Increase value from existing assets — NRG has a highly diversified portfolio of power generation assets in terms of region, fuel-type and dispatch levels. NRG will continue to focus on extracting value from its portfolio by improving plant performance, reducing costs and harnessing the Company's advantages of scale in the procurement of fuels and other commodities, parts and services, and in doing so improve the Company's return on invested capital, or ROIC — a strategy that NRG has branded *FORNRG,* or Focus on ROIC@NRG.

Maintain financial strength and flexibility — NRG remains focused on cash flow and maintaining appropriate levels of liquidity, debt and equity in order to ensure continued access to capital for investment, to enhance risk-adjusted returns and to provide flexibility in executing NRG's business strategy. NRG will continue to focus on maintaining operational and financial controls designed to ensure that the Company's financial position remains strong. At the same time, NRG expects to continue its practice of returning excess cash flows to its debt and equity investors on a regular basis.

Reduce the volatility of the Company's cash flows through asset-based commodity hedging activities — NRG will continue to execute asset-based risk management, hedging, marketing and trading strategies within well defined risk and liquidity guidelines in order to manage the value of the Company's physical and contractual assets. The Company's marketing and hedging philosophy is centered on generating stable returns from its portfolio of baseload power generation assets while preserving an ability to capitalize on strong spot market conditions and to capture the extrinsic value of the Company's intermediate and peaking facilities and portions of its baseload fleet. NRG believes that it can successfully execute this strategy by leveraging its expertise in marketing power and ancillary services, its knowledge of markets, its balanced financial structure and its diverse portfolio of power generation assets.

Pursue strategic acquisitions and divestures — NRG will continue to pursue selective acquisitions, joint ventures and divestitures to enhance its asset mix and competitive position in the Company's core regions to meet the fuel and dispatch requirements in these regions. NRG intends to concentrate on opportunities that present attractive risk-adjusted returns. NRG will also opportunistically pursue other strategic transactions, including mergers, acquisitions or divestitures.

Business Environment

General Industry — 2006 was yet another year of progress and transition for the power generation industry. The industry dynamics and external influences that are most likely to significantly affect the Company and the power generation industry in 2007 include:

Emissions — Environmental compliance policies on a federal and state level continue to accelerate in a variety of ways, presenting challenges to the industry as a result of various uncertainties. In the case of SO_2 and NOx, the regulatory regime is well-settled but the tightening standards taking effect in 2010 and 2014 have caused a need to add capital intensive "back end" controls. This remediation requirement has led to dramatic increases in, and uncertainty with respect to, the ultimate cost to comply with the stricter regulations. In the case of mercury (Hg), there is greater regulatory and technical uncertainty as various states have imposed, or are intending to impose, tougher standards than currently provided for under federal law and the technological solutions to comply with such standards are less certain both with respect to efficacy and cost. Finally, the move towards federal carbon regulation to combat global warming is gaining momentum but the timing, shape and ultimate disposition of that legislation and the impact it will have are unknown.

Consolidation — Two "mega-utility" combinations (FPL Group Inc./Constellation Energy Group and Exelon Corp./PSEG) failed due to state regulatory opposition in 2006. While there are still likely to be some regulated utility mergers in the future, mergers and acquisitions activity in the power generation sector for the time being are likely to involve utility-merchant or merchant-merchant combinations and acquisitions by private equity funds or consortia of power generation assets, portfolios or entire companies. There may also be interest by foreign power companies, particularly European utilities, in the American power generation sector.

Infrastructure Development — In response to record peak demand, tightening reserve margins, persistently high and volatile natural gas prices and ever increasing environmental sensitivity, the power generation industry has announced significant expansion plans for both transmission and generation. In stark contrast to the previous wave of new power generation in the United States, which was almost exclusively natural gas-fired, much of the new generation announced around the nation has focused on non-gas fuel sources, including coal, nuclear and renewable sources.

Capacity Markets — Considerable progress was made in ISO-NE and PJM towards approval and implementation of locational capacity markets. The CPUC also took steps towards establishing locational capacity requirements, thus a bilateral market for capacity. The objective of such market structures is to provide timely and accurate market signals to encourage new investment in transmission and new generation in the locations where the new investment is needed.

Commodity Prices and Volatility — Commodity prices have abated after hitting record highs during 2005. The single biggest driver on a national level for the downtrend in prices has been driven primarily by mild weather conditions resulting in excess gas storage due to below normal withdrawals. However, volatility continues to predominate the commodities market with many financial and hedge fund players seeking to participate and build up their trading positions in the energy sector.

Skills Scarcity — After more than a decade long contraction of the power generation industry's workforce, the industry finds itself poised for expansion, but hampered by an aging workforce, with current and projected shortages of experienced engineers, skilled operators, and maintenance workers. This skills deficit also has the potential to hamper the power generation industry's ability to design and construct the next wave of power generation infrastructure needed in this country.

Competition

Competition — Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. NRG competes on the basis of the location of its plants and owning multiple plants in its regions, which increases the stability and reliability of its energy supply. Wholesale power generation is basically a local business that is currently highly fragmented relative to other commodity industries and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identity of the companies NRG competes against depending on the market.

Regulatory

As an operator of power plants and a participant in the wholesale markets, NRG is subject to regulation by various federal and state government agencies. These include CFTC, FERC, NRC, PUCT and other public utility commissions in certain states where NRG's generating assets are located. In addition, NRG is also subject to the market rules, procedures, and protocols of the various ISO markets in which NRG participates. These wholesale power markets are subject to ongoing legislative and regulatory changes. The Company cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on NRG's business. NRG supports the efficient operation of the wholesale markets; however, opposition to wholesale power markets has increased. Support for the mitigation of sellers has increased in order to reduce prices. In some of NRG's regions, interested parties have advocated for material market design changes, including the elimination of a single clearing price mechanism, as well as proposals to re-regulate the markets or require divestiture by generating companies to reduce their market share.

Weather

Weather conditions in the different regions of the United States influence the financial results of NRG's businesses. Weather conditions can affect the supply and demand for electricity and fuels. Changes in energy supply and demand may impact the price of these energy commodities in both the spot and forward markets, which may affect the Company's results in any given period. Typically, demand for and the price of electricity is higher in the summer and the winter seasons, when temperatures are more extreme. The demand for and price of natural gas and oil are higher in the winter. However, all regions of North America typically do not experience extreme weather conditions at the same time, thus NRG is typically not exposed to the effects of extreme weather in all parts of its business at once.

Other Factors

A number of other factors significantly influence the level and volatility of prices for energy commodities and related derivative products for NRG's business. These factors include:

- seasonal daily and hourly changes in demand;
- extreme peak demands;
- available supply resources;
- transportation and transmission availability and reliability within and between regions;
- location of NRG's generating facilities relative to the location of its load-serving opportunities;
- procedures used to maintain the integrity of the physical electricity system during extreme conditions; and
- changes in the nature and extent of federal and state regulations.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions;
- market liquidity;

- capability and reliability of the physical electricity and gas systems;
- local transportation systems; and
- the nature and extent of electricity deregulation.

Environmental Matters and Legal Proceedings

NRG discusses details of its environmental matters in Item 15 — Note 23, *Environmental Matters*, to its Consolidated Financial Statements and Item 1, *Business — Environmental Matters,* section. NRG discusses details of its legal proceedings in Item 15 — Note 21, *Commitments and Contingencies*, to its Consolidated Financial Statements. Some of this information is about costs that may be material to the Company's financial results.

Impact of inflation on NRG's results

Unless discussed specifically in the relevant segment, for the years ended December 31, 2006, 2005 and 2004, the impact of inflation and changing prices (due to changes in exchange rates) on NRG's revenues and income from continuing operations was immaterial.

Capital Allocation Strategy

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

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

Known Trends and Uncertainties

- Initiation of a portfolio repowering effort to add approximately 10,350 MW of new multi-fuel, multi-technology generation capacity at NRG's existing domestic sites to meet growing demand in all of the Company's core domestic markets.
- Continued share repurchases through the Company's Capital Allocation Program.
- Increasing the baseload hedge profile to 59% in 2010, 65% in 2011 and 24% in 2012, to provide certainty around the Company's future cash flows.

Significant events that affected NRG's results of operations for the year ended December 31, 2006

Operational

- Reset legacy Texas region long-term out-of-market power contracts and gas swaps by negotiating to current market price levels resulting in a reduction in operating income of $135 million.

- Total generation increased by 154% primarily due to the addition of the Texas region to the NRG total portfolio.
- Improved operating performance and new tolling agreements contributed to $97 million of higher operating income from the South Central region.
- A mild winter and summer coupled with weak power prices lowered generation demand for the Northeast region's generation assets by 18%.
- NRG recorded $187 million in refinancing costs and $599 million in interest expense primarily due to new debt facilities associated with the acquisition of NRG Texas.
- Record peak energy demand in each of the market's served by NRG's major business segments ranging with increases of 4% to 11% over previous records.
- Recognized $124 million in gains from risk management activities.

Acquisitions/Dispositions

- On February 2, 2006, NRG acquired Texas Genco LLC. Texas Genco LLC and its affiliates are now wholly-owned subsidiaries of NRG, and is managed and accounted for as a separate business segment referred to as Texas region.
- On August 30, 2006, NRG announced the completion of the sale of its 100% owned Flinders power station and related assets. NRG received approximately $242 million in cash and recognized an after-tax gain on the sale of approximately $60 million.
- On March 31, 2006, NRG acquired Dynegy's 50% ownership interest in WCP, and became the sole owner of WCP's 1,825 MW of generation in Southern California. The results of operations of WCP were consolidated as of April 1, 2006, prior to which, NRG's 50% ownership of WCP was recorded as an equity method investment.
- On November 8, 2006, NRG completed the sale of its Newport and Elk River Resource Recovery facilities, its Becker Ash Disposal facility as well as its ownership in NRG Processing Solutions, LLC, to Resource Recovery Technologies, LLC for approximately $22 million. The Company recognized a gain of approximately $5 million.

Other

- On January 31, 2006, NRG finalized a settlement agreement with an equipment manufacturer related to certain turbine purchase agreements. Upon finalization of the settlement, NRG recorded a total of $67 million of other income, of which $35 million was related to the discharge of accounts payable previously recorded and $32 million was related to the receiving and recording of the equipment at fair value.
- Incurred approximately $36 million in development costs primarily related to *Repowering NRG* program.

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Consolidated Results of Operations

2006 compared to 2005

The following table provides selected financial information for NRG Energy, Inc., for the years ended December 31, 2006 and 2005.

	Year Ended December 31, 2006	Year Ended December 31, 2005	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 3,193	$ 1,870	71%
Capacity revenue	1,516	563	169
Risk management activities	124	(292)	NA
Contract amortization	628	9	NA
Thermal revenue	124	124	—
Hedge Reset	(129)	—	NA
Other revenues	167	156	7
Total operating revenues	5,623	2,430	131
Operating Costs and Expenses			
Cost of operations	3,276	1,838	78
Depreciation and amortization	593	162	266
General, administrative and development	316	181	75
Impairment charges	—	6	NA
Corporate relocation charges	—	6	NA
Total operating costs and expenses	4,185	2,193	91
Operating Income	1,438	237	507
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	60	104	(42)
Write downs and gains/(losses) on sales of equity method investments	8	(31)	NA
Other income, net	160	58	176
Refinancing expenses	(187)	(65)	188
Interest expense	(599)	(184)	226
Total other expenses	(558)	(118)	373
Income from Continuing Operations before income tax expense	880	119	639
Income tax expense	325	47	591
Income from Continuing Operations	555	72	671
Income from discontinued operations, net of income tax expense	66	12	450
Net Income	$ 621	$ 84	639
Business Metrics			
Average natural gas price — Henry Hub ($/MMbtu)	6.75	8.89	(24)%

For the benefit of the following discussions, the table below represents the results of NRG excluding the impact of the Company's Texas region, the Hedge Reset and WCP:

	Year Ended December 31, 2006				2005
	Consolidated	Texas Region	WCP	Total excluding Texas Region/WCP	Consolidated
	(In millions)				
Energy revenue	$ 3,193	$ 1,726	$ 72	$ 1,395	$ 1,870
Capacity revenue	1,516	849	64	603	563
Risk management activities	124	(30)	—	154	(292)
Contract amortization	628	609	—	19	9
Thermal revenue	124	—	—	124	124
Hedge Reset	(129)	(129)	—	—	—
Other revenues	167	63	5	99	156
Total Operating revenues	5,623	3,088	141	2,394	2,430
Cost of operations	3,276	1,669	112	1,495	1,838
Depreciation and amortization	593	413	2	178	162
General, administrative and development	316	125	10	181	181
Impairment charges	—	—	—	—	6
Corporate relocation charges	—	—	—	—	6
Total operating costs and expenses	4,185	2,207	124	1,854	2,193
Operating Income	$ 1,438	$ 881	$ 17	$ 540	$ 237

Operating Revenues

Total operating revenues were $5,623 million for the year ended December 31, 2006 compared to $2,430 million for the year ended December 31, 2005, an increase of $3,193 million. Energy revenues for the year ended December 31, 2006 increased $1,323 million from $1,870 million to $3,193 million, with 51% contracted compared to 2005 when 14% was contracted. The current year's results were favorably impacted by the acquisition of Texas Genco LLC, now referred to as the Company's Texas region, which contributed $3,088 million to operating revenues including $1,726 million of energy revenues, $849 million of capacity revenues and $609 million of contract amortization revenues. In addition, the acquisition of Dynegy's 50% interest in WCP contributed $141 million to total operating revenues. Excluding the Company's Texas region, the Hedge Reset transaction and WCP, total operating revenues for the current year decreased by $36 million. Energy revenues, excluding the Texas region and WCP, declined by $475 million, or 25%, as generation demand for the Northeast region's intermediate and peaking plants declined by 54%, accompanied by a 19% to 23% year over year decline in power prices in the Northeast region's three major markets. Reduced revenues due to lower generation were partially offset by $446 million in gains from risk management results as such activities swung from last year's loss of $292 million to a gain of $154 million, primarily due to the decline in settled and forward prices of electricity and natural gas.

Capacity revenues for the year ended December 31, 2006 were $1,516 million compared to $563 million for the year ended December 31, 2005, an increase of $953 million. Of this increase, $849 million was related to the Company's Texas region, primarily from auction sales. In addition, capacity revenues increased $64 million in the West region due to the acquisition of WCP. Increased capacity revenues, reflective of higher capacity prices for the New York Rest of State market, led to a $30 million increase in the Northeast region's 2006 yearly capacity revenue. The South Central region's capacity revenues also grew by $9 million as pricing increased due to increased peak demand.

Risk Management Activity — The following table shows NRG's risk management activities that do not qualify for hedge accounting treatment for the year ended December 31, 2006.

	Year Ended December 31, 2006				
	Texas	Northeast	South Central	Other	Total
	(In millions)				
Financial revenues					
Net losses on settled positions, or financial revenues	(152)	(10)	(6)	(3)	(171)
Subtotal net losses on settled positions, or financial revenues	(152)	(10)	(6)	(3)	(171)
Mark-to-market results					
Reversal of previously recognized unrealized losses on settled positions	—	90	—	—	90
Net unrealized gains on open positions related to economic hedges	122	50	—	—	172
Net unrealized gains on open positions related to trading activity		14	19	—	33
Subtotal mark-to-market results	122	154	19	—	295
Total derivative gain/(losses)	$ (30)	$ 144	$ 13	$ (3)	$ 124

Risk management activities that do not qualify for hedge accounting treatment resulted in a total derivative gain of approximately $124 million for the year ended December 31, 2006 compared to a $292 million loss for the year ended December 31, 2005. For the year ended December 31, 2006, these losses were comprised of $171 million in settled financial revenue losses and $295 million of mark-to-market gains. The $171 million loss in financial revenues represents the settled value for financial instruments that do not qualify for hedge accounting treatment and were primarily related to $152 million in losses of gas swaps acquired with the purchase of Texas Genco LLC. Of the $295 million in mark-to-market gains, $172 million represents the change in the fair value of forward sales of electricity and fuel, including $28 million of hedge accounting ineffectiveness related to hedge contracts in the Company's Texas region due to a decline in the correlation between natural gas and power prices. In addition, $90 million of the $295 million mark-to-market gains represents the reversal of mark-to-market losses, which ultimately settled as financial revenues. NRG also recognized a $33 million gain associated with the Company's trading activity.

Since NRG's risk management activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in these 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 instrument hedges that qualify for hedge accounting treatment) and costs of energy. In late 2005 and in 2006, NRG hedged a portion of the Company's 2006 and 2007 Northeast region's generation. Since that time, the settled and forward prices of electricity have decreased, resulting in the recognition of mark-to-market forward sales and the settlement of such positions at reduced losses.

Hedge Reset

In November 2006, NRG executed a series of transactions designed to both extend and strengthen the Company's baseload hedging positions and to enable further optimization of the Company's ongoing Capital Allocation Program. It involved net settling legacy Texas region long-term power contracts and gas swaps by negotiating prices to current market levels with certain counterparties. This resulted in the accelerated amortization of approximately $1,073 million of out-of-market power contracts and $145 million of gas swaps derivative liability offset by a payment of approximately $1,347 million to the counterparties, for a net reduction of approximately $129 million in the Company's total operating revenues. In addition, as part of NRG's Hedge Reset transactions, the Company recorded $6 million of costs related to the transaction.

Cost of Operations

Cost of operations includes cost of energy, operating and maintenance expenses, and non-income tax expenses. For the year ended December 31, 2006, cost of operations was $3,276 million or 58% of total operating revenues compared to $1,838 million, or 76%, of total operating revenues for 2005, an increase of $1,438 million. This increase in absolute terms, but decrease in relative percentage terms, was primarily due to the acquisition of the Company's Texas region which incurred costs of $1,669 million. Cost of energy which includes fuels, purchased power, and cost contract amortization increased from $1,431 million for 2005 to $2,460 million in 2006. The increase of $1,029 million was primarily due to the Company's Texas region, which incurred $1,276 million in cost of energy and WCP, which incurred $79 million of energy cost this year, partially offset by lower cost of energy in the Company's Northeast region. Excluding NRG Texas and WCP, cost of energy decreased by $326 million. This decrease was driven by $254 million in lower cost of energy in the Northeast region, primarily due to $143 million lower oil costs and $101 million in lower gas fuel costs related to lower generation from oil- and gas-fired assets of approximately 70% and 45%, respectively. The South Central region's cost of energy was $66 million lower in 2006, as higher coal plant availability and increased utilization of the region's tolling agreements reduced the need to purchase energy to support contract load requirements.

Other operating costs increased in 2006 by $410 million to $816 million, $393 million related to the acquisition of NRG Texas and $33 million for WCP. Excluding the impact of NRG Texas and WCP, other operating costs were $16 million lower than last year primarily due to lower operating and maintenance costs, which benefited in the second quarter 2006 from an accrual reversal of $18 million related to a favorable court decision in a station service dispute at NRG's Western New York plants. In addition, as part of NRG's Hedge Reset transactions, the Company recorded $6 million of costs related to the transaction.

Depreciation and Amortization

NRG's annual depreciation and amortization expense for 2006 and 2005 was $593 million and $162 million, respectively. The Texas region's depreciation and amortization comprised $413 million of the $431 million year-over-year increase.

General, Administrative and Development, or G&A

NRG's G&A costs for 2006 were $316 million compared to $181 million in the previous year. Corporate costs represented $143 million, or 3% of 2006 total operating revenues and $112 million, or 5% of the Company's 2005 total operating revenues. G&A costs were adversely impacted by $6 million of costs associated with the unsolicited acquisition offer by Mirant Corporation and approximately $14 million of NRG Texas integration costs. The balance of the corporate increase was mainly comprised of increased staffing and administrative costs after the acquisition of Texas Genco LLC. Total G&A costs, excluding WCP and the Company's Texas region remained flat at $181 million. NRG also incurred approximately $36 million in development expenses in 2006 to support its recently announced *Repowering NRG* program.

Equity in Earnings of Unconsolidated Affiliates

Equity earnings from NRG's investments in unconsolidated affiliates were $60 million for the year ended December 31, 2006, compared to $104 million for the year ended December 31, 2005, a decline of approximately 42%. The decline in earnings was primarily due to the sale of certain non-core assets that were completed during 2006 as well as the Company's purchase of WCP. NRG's purchase of the remaining 50% interest in WCP accounted for $21 million of the decline, as the results of WCP were fully consolidated as of March 31, 2006. As part of that transaction, NRG sold its 50% interest in the Rocky Road investment, which accounted for $7 million of the decline in total equity earnings. In addition, NRG's Enfield investment, which was sold on April 1, 2005, earned $16 million during 2005. Sales of other equity investments in 2006 included James River, Cadillac and certain Latin American power funds. Declines in equity earnings as a result of these sales were partially offset by a $4 million improvement in equity income from the Company's MIBRAG investment. MIBRAG experienced improved results compared to 2005 as a result of fewer customer outages.

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

During 2006, NRG continued to divest of its non-core assets by selling the Company's interests in James River and Cadillac, as well as interests in certain Latin American power funds for a pre-tax loss of $6 million, a pre-tax gain of $11 million and a pre-tax gain of $3 million, respectively.

For the year ended December 31, 2005, NRG recorded a $31 million loss due to the sale and impairment of certain equity investments. On April 1, 2005, NRG sold its 25% interest in Enfield, resulting in net pre-tax proceeds of $65 million and a pre-tax gain of $12 million. In 2005, NRG also sold its interest in Kendall and recorded a pre-tax gain of approximately $4 million. These gains on sales were offset by approximately $47 million in impairment charges recorded last year. In December 2005, NRG executed an agreement with Dynegy to sell the Company's 50% interest in Rocky Road LLC in conjunction with NRG's purchase of Dynegy's 50% interest in WCP. Based on the terms of the transaction which valued the Company's investment in Rocky Road at $45 million, NRG impaired its interest in Rocky Road by writing down the value of the investment by approximately $20 million. The sale of Rocky Road closed on March 31, 2006. In 2005, NRG also recorded an impairment of $27 million on its investment in the Saguaro power plant. With the expiration of the plant's long-term gas supply contract, the Saguaro power plant became exposed to the risk of fluctuating natural gas prices beginning in the second half of 2005, triggering a permanent write down of NRG's investment value in Saguaro.

Other Income, Net

Other income increased by $102 million for the year ended December 31, 2006 to $160 million compared to the same period in 2005. Other income in 2006 was favorably impacted by $67 million of income associated with a non-cash settlement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001, a $13 million non-cash gain associated with the discharge of liabilities upon dissolution of an inactive legal entity, and $5 million from the favorable settlement with respect to post closing adjustments on the acquisition of the Company's western New York plants in 1998 and 1999. In 2005, NRG recorded an $11 million gain from the settlement related to the Company's TermoRio project in Brazil and a contingent gain of $4 million related to the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. Other income was also favorably impacted in 2006 by $25 million of higher interest income related to higher levels of cash and more efficient management of cash balances.

Refinancing Expenses

Refinancing expenses incurred in 2006 and 2005 were $187 million and $65 million, respectively. In the first quarter 2006, NRG partially financed the acquisition of Texas Genco LLC through borrowings under new debt facilities and repaid and terminated previous debt facilities. As a result of this financing, the Company incurred $178 million of refinancing expenses: $127 million was related to the premium paid to NRG's previous debt holders, $34 million for the amortization of the remaining balance of a bridge loan commitment entered into on September 30, 2005, and $31 million related to write-offs of deferred financing costs associated with NRG's previous debt, and a credit of $14 million related to a debt premium write-off. In 2005, NRG redeemed and purchased a total of approximately $645 million of the Company's second priority notes. As a result of the redemption and purchases, NRG incurred approximately $54 million in premiums and write-offs of deferred financing costs. NRG also incurred an additional $11 million in refinancing fees during the fourth quarter of 2005 related to the amortization of a bridge loan commitment fee that the Company paid related to acquisition financing.

Interest Expense

Interest expense for the year ended December 31, 2006 was $599 million compared to $184 million for the year ended December 31, 2005. The increase in interest expense was primarily due to interest on new debt issued to finance the acquisition of Texas Genco LLC. See Item 15 — Note 3, *Business Acquisitions and Dispositions*, and Note 11, *Debt and Capital Leases*, to the consolidated financial statements for a further discussion of the acquisition and the related financing. As part of the refinancing, NRG replaced its previous senior secured term loan with a new $3.575 billion senior secured term loan. In addition, NRG retired $1.1 billion of its 8% second priority notes and issued $3.6 billion in senior unsecured notes with a weighted average interest rate of 7.33%.

In the first quarter 2006, NRG entered into interest rate swaps with the objective of fixing the interest rate on a portion of the Company's new Senior Credit Facility. These swaps were designated as cash flow hedges under FAS 133, and any impact associated with ineffectiveness was immaterial to NRG's financial results. For the year ended December 31, 2006, NRG had deferred gains of $16 million in other comprehensive income associated with these swaps. Also See Item 15 — Note 11, *Debt and Capital Leases*, to the consolidated financial statements for a further discussion on these interest rate swaps. In addition, NRG designated an existing fixed-to-floating interest rate swap, previously as a hedge of NRG's 8% second priority notes, into a fair value hedge of the Senior Notes, which NRG closed on February 2, 2006.

Income Tax Expense

Income tax expense was approximately $325 million and approximately $47 million for the years ended December 31, 2006 and 2005, respectively. The overall effective tax rate was approximately 36.9% and 39.5% for the years ended December 31, 2006 and 2005, respectively. The effective income tax rate for the years ended December 31, 2006 and 2005 differ from the U.S. statutory rate of 35% due to a basis difference relating to disbursements from the Company's disputed claims reserve, a change in the Company's state effective income tax rate due to the acquisition of the Company's Texas region, and the Company's earnings in foreign jurisdictions, which are taxed at rates lower than the U.S. statutory rate.

	Year Ended December 31,	
	2006	2005
	(In millions except otherwise stated)	
Income from continuing operations before income taxes	$ 880	$ 119
Tax at 35%	308	42
State taxes, net of federal benefit	34	(1)
Foreign operations	(23)	(16)
Section 965 taxable dividend	—	5
Subpart F taxable income	11	19
Valuation allowance, including change in state effective rate	(10)	22
Change in state effective tax rate	21	(22)
Claimant Reserve settlements	(28)	—
Permanent differences, reserves, other	12	(2)
Income tax expense	$ 325	$ 47
Effective income tax rate	36.9%	39.5%

The Company's effective income tax rate may vary from period to period depending on, among other factors, the Company's geographic and business mix of earnings and losses and the Company's adjustment of valuation allowance in accordance with SFAS 109. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize the Company's deferred tax assets. The Company's valuation allowance has been reduced in 2006 due to earnings generated from business operations and due to the acquisition of the Company's Texas region.

Income from Discontinued Operations, Net of Income Tax Expense

NRG classifies as discontinued operations the income from operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the years ended December 31, 2006 and 2005, NRG recorded income from discontinued operations, net of income tax expense of $66 million and $12 million, respectively. Discontinued operations for the year ended December 31, 2006 were comprised of the results of Flinders, Audrain and Resource Recovery. Discontinued operations for 2005 consisted of the results of the Flinders, Audrain, Resource Recovery, Northbrook New York LLC, Northbrook Energy LLC and NRG McClain LLC. NRG closed on the sale of Flinders during the third quarter 2006 and recognized an after-tax gain of approximately $60 million from the sale. Discontinued operations for the full year 2005 included an $11 million gain on the disposition of NRG's Northbrook New York and Northbrook Energy operations.

2005 compared to 2004

The following table provides selected financial information for NRG Energy, Inc., for the years ended December 31, 2005 and 2004:

	Year Ended December 31, 2005	2004	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 1,870	$ 1,205	55%
Capacity revenue	563	612	(8)
Thermal revenue	124	112	11
Risk management activities	(292)	61	N/A
Contract amortization	9	(6)	N/A
Other revenues	156	120	30
Total operating revenues	2,430	2,104	15
Operating Costs and Expenses			
Cost of operations	1,838	1,290	42
Depreciation and amortization	162	179	(9)
General, administrative and development	181	197	(8)
Impairment charges	6	45	(87)
Reorganization charges	—	(13)	N/A
Corporate relocation charges	6	16	(63)
Total operating costs and expenses	2,193	1,714	28
Operating Income	237	390	(39)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	104	160	(35)
Write downs and gains/(losses) on sales of equity method investments	(31)	(16)	94
Other income, net	58	22	164
Refinancing expenses	(65)	(72)	(10)
Interest expense	(184)	(255)	(28)
Total other expenses	(118)	(161)	(27)
Income from Continuing Operations before income tax expense	119	229	(48)
Income tax expense	47	74	(36)
Income from Continuing Operations	72	155	(54)
Income from discontinued operations, net of income tax expense	12	31	(61)
Net Income	$ 84	$ 186	(55)
Business Metrics			
Average natural gas price — Henry Hub ($/MMbtu)	8.89	5.89	51%

N/A

Total Operating Revenues

Total operating revenues were $2,430 million for the year ended December 31, 2005 compared to $2,104 million for the year ended December 31, 2004, an increase of $326 million. Energy revenues for the year ended December 31, 2005 increased $665 million from $1,205 million to $1,870 million. Of the $1,870 million, 86% was merchant as compared to 66% for the year ended December 31, 2004. The increase in energy revenue was driven by both increased prices and increased merchant generation from the Company's Northeast assets. Energy revenues from NRG's domestic coal assets increased by $314 million, primarily due to increased power prices, as generation from the Company's domestic coal-fired assets decreased 5% for the year ended December 31, 2005, compared to the same period in 2004. This decrease in generation was due to both planned and unplanned outages at the Company's Huntley, Indian River, and Big Cajun II plants during the second and fourth quarters of 2005. Energy revenues from NRG's gas-fired assets in New York City increased by $176 million, which included $23 million in NYISO final settlement payments. Of the remaining $153 million increase, price and generation contributed equally. Energy revenues from NRG's oil-fired assets rose by $209 million, 86% due to higher volumes following an increase in summer demand as the generation from these assets increased by 122% for the year ended December 31, 2005, compared to the same period in 2004. In addition, a one-time payment of $39 million from the Connecticut Light and Power settlement contributed to energy revenue during the second quarter of 2004.

Capacity revenues for the year ended December 31, 2005 were $563 million compared to $612 million for the year ended December 31, 2004, a reduction of $49 million. The decrease in capacity revenues compared to the prior year was primarily due to a loss of $56 million in capacity revenues from the Company's Kendall facility, which was sold in the fourth quarter of 2004, and the expiration of the South Central region's Rockford tolling agreement, which expired in May 2005 and reduced capacity revenues by $23 million. Capacity revenues from the Company's western New York plants decreased by $10 million due to the addition of new generation and increased imports in New York, which depressed capacity prices for the Company's assets in the western New York market during the first half of 2005. This loss was offset by a $44 million increase in capacity revenues from the Company's Connecticut assets, of which $24 million was related to the Connecticut RMR settlement agreement.

Thermal revenues for the years ended December 31, 2005 and 2004 were $124 million and $112 million, respectively. Increased generation due to the warmer weather during the summer of 2005 and an increase in contract rates from the Company's thermal operations positively contributed to the improved results.

Other revenues include emission allowance sales, natural gas sales, and expense recovery revenues. For the year ended December 31, 2005, other revenues totaled $165 million, compared to $114 million for the same period in 2004. The increase was primarily due to higher emission allowance revenues and higher physical gas sales, which were partially offset by lower expense recovery revenues. The increase in gas sales of approximately $32 million was primarily related to a new gas sale agreement entered into in the third quarter of 2005 by the South Central region, where revenues from gas sales increased by $23 million. NRG entered into this agreement in conjunction with power purchase agreements to minimize market purchases by the region during peak months. Finally, expense recovery revenues in 2005 were $29 million lower compared to 2004. Expense recovery revenues associated with the Company's Connecticut RMR agreements reached its maximum payment during the first quarter 2005.

Risk Management Activity — The total derivative loss for the year ended December 31, 2005 was approximately $292 million, comprised of $138 million in settled financial revenue losses and $154 million of mark-to-market losses. The $138 million loss in financial revenues represents the settled value for the year 2005 of financial instruments that do not qualify for hedge accounting treatment. Of the $154 million of mark-to-market losses, $122 million represented the change in fair value of forward sales of electricity and fuel, and $59 million represented the reversal of mark-to-market gains which ultimately settled as financial revenues. These activities primarily supported the Company's Northeast assets.

The following table shows NRG's risk management activities that do not qualify for hedge accounting treatment for the year ended December 31, 2005.

	Year Ended December 31, 2005			
	Northeast	South Central	Other	Total
	(In millions)			
Net losses on settled positions, or financial revenues	$ (132)	$ (1)	$ (5)	$ (138)
Mark-to-market results				
Reversal of previously recognized unrealized gains on settled positions	(59)	—	—	(59)
Net unrealized losses on open positions related to economic hedges	(121)	(1)	—	(122)
Net unrealized gains on open positions related to trading activity	27	—	—	27
Subtotal mark-to-market results	(153)	(1)	—	(154)
Total derivative loss	$ (285)	$ (2)	$ (5)	$(292)

Since NRG's economic hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. In the fourth quarter of 2004 and during the course of 2005, NRG hedged much of its calendar year 2005 and 2006 Northeast generation. Since that time, the settled and forward prices of electricity have risen, driven by the extreme weather conditions in the summer of 2005. While this increase in electricity prices benefited NRG's generation portfolio compared to 2004 with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

Cost of Operations

Cost of operations for the year ended December 31, 2005 was $1,838 million. Cost of operations for the year ended December 31, 2004 was $1,290 million, or 61% of total operating revenues. The increase was primarily related to higher cost of energy, which increased by $506 million to $1,431 million, or 59% of revenues, for the year ended December 31, 2005, from $925 million, or 44% of revenues for the same period, in 2004. The increase in cost of energy as a percentage of revenues was driven by both higher prices and generation in the Company's Northeast region and higher purchased energy and gas sales in the Company's South Central region. Total gas costs increased by $162 million, with $124 million attributable to the Company's New York City assets, of which approximately $15 million was due to increased gas purchases for resale and approximately $67 million was due to increased generation. The South Central region's gas costs also increased by $31 million due to physical gas purchases related to a new gas sale agreement entered into in the third quarter of 2005 to support certain tolling arrangements. Total oil costs for the Company increased by $164 million, 65% due to increased generation from the Company's oil-fired assets, with the remainder due to an increase in price. Total coal costs increased by $71 million as a result of higher coal prices for the Company's domestic coal-fired assets, as overall generation from the Company's coal-fired assets decreased for the year ended December 31, 2005 by 5%, compared to the same period in 2004, due to both planned and forced outages at the Company's Huntley, Indian River and Big Cajun II facilities. The increase in coal prices was related to new low-sulfur coal and rail contracts, which became effective in April 2005. In addition, NRG's Indian River plant, which uses a higher portion of eastern coal, experienced a significant cost increase in 2005. The Company has increased its percentage blend of low-sulfur coal over the year as compared to the same period last year. This had the effect of mitigating the increase in coal and coal transportation costs, as low sulfur coal prices have not increased as much as regular coal prices. Total purchased energy increased by $102 million due to increases at the Company's South Central region. Higher long-term contract load demand due to the extreme weather, a 100-MW around-the-clock sale to Entergy, a tolling agreement, and the forced outages during the second quarter 2005, required South Central to purchase energy to meet its contract load obligations.

Other operating costs for the year ended December 31, 2005 totaled $406 million compared to $365 million in the comparable period of 2004, an increase of $41 million. This increase was driven by a $34 million increase in normal and maintenance costs as a result of more major maintenance projects and extensive outages in 2005 compared to 2004. The low-sulfur coal conversions and turbine overhauls of the Company's western New York plants and Indian River plant was a main focus for many of the major maintenance and outages in 2005. The South Central region also went through a significant outage to install a low-NO_x burner on one of its units and an additional outage was completed in the fall of 2005 to address reliability issues experienced at the Big Cajun II unit earlier in the year. In 2004, a settlement with a third party vendor regarding auxiliary power charges reduced 2004 operating and maintenance expenses by $7 million.

Depreciation and Amortization

Depreciation and amortization expenses for the years ended December 31, 2005 and 2004 was approximately $162 million and $179 million, respectively. The decrease in depreciation and amortization from 2005 to 2004 was primarily due to the 2004 sale of the Company's Kendall plant, which contributed approximately $14 million in depreciation and amortization expense during 2004.

General, Administrative and Development, or G&A

G&A costs for the year ended December 31, 2005 were $181 million, compared to $197 million for the same period in 2004, a decrease of $16 million. Corporate costs represented $108 million, or 4% of revenues and $132 million, or 6% of revenues, for the years ended December 31, 2005 and 2004, respectively. G&A costs were favorably impacted by approximately $11 million in reduced bad debt expense associated with notes receivable from third parties. In addition, external consulting expenses decreased in 2005 as compared to 2004 by approximately $12 million, primarily related to reduced tax and legal consulting. These favorable impacts were offset by a $5 million increase in information technology related expenses, primarily associated with increased compliance costs related to Sarbanes Oxley and the relocation of the Company's corporate headquarters from Minneapolis.

Corporate Relocation Charges

For the year ended December 31, 2005, charges related to the company's corporate relocation activities were approximately $6 million, as compared to $16 million in 2004. Included in 2005's charges was approximately $3 million related to lease abandonment charges associated with the Company's former Minneapolis office, with the remainder related to relocation, recruitment and transition costs. In 2004, NRG recorded $16 million primarily related to employee severance and termination benefits and employee-related transition costs. NRG completed the physical move of the Company's corporate headquarters in 2004 when the majority of costs were incurred.

Equity in Earnings of Unconsolidated Affiliates

For the year ended December 31, 2005, equity earnings from the Company's investments in unconsolidated affiliates were $104 million compared to $160 million for the year ended December 31, 2004, a decrease of $56 million. NRG's earnings in WCP accounted for $22 million and $69 million for the years ended December 31, 2005 and 2004, respectively. The decrease in WCP's equity earnings was due to the expiration of the CDWR contract in December 2004. The equity earnings of the Company's Enfield investment were $13 million lower for the year ended December 31, 2005 as compared to the same period in 2004, which was sold on April 1, 2005. In addition, for the year ended December 31, 2005, the results of the Company's Enfield investment included approximately $12 million of unrealized gains associated with mark-to-market increases in the fair value of energy-related derivative instruments, compared to $23 million of unrealized gains for the same period in 2004.

Other equity investments included in the Company's 2005 results included MIBRAG and Gladstone, which comprised $26 million and $24 million for the year ended December 31, 2005, respectively. For the comparable period in 2004, MIBRAG and Gladstone earned $21 million and $18 million, respectively. MIBRAG's equity earnings for 2004 were negatively impacted by an outage at the Company's Schkopau plant; in addition, MIBRAG recorded a lower asset retirement obligation in 2005 as compared to 2004. Gladstone's earnings in 2005 were greater than 2004 due to lower major maintenance expense.

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

For the year ended December 31, 2005, NRG recorded a $31 million loss due to the sale and impairment of certain equity investments as the Company continued the divestiture of its non-core assets. On April 1, 2005, NRG sold its 25% interest in Enfield, resulting in net pre-tax proceeds of $65 million and a pre-tax gain of $12 million, including post-closing working capital adjustments. In 2005, NRG also sold its interest in Kendall for $5 million in pre-tax proceeds and a pre-tax gain of approximately $4 million. These gains on sales were offset by approximately $47 million in impairment charges recorded during the year.

In December 2005, NRG executed an agreement with Dynegy to sell the Company's 50% interest in Rocky Road LLC in conjunction with NRG's purchase of Dynegy's 50% interest in WCP. Based on the terms of the transaction, which valued the Company's investment in Rocky Road at $45 million, NRG impaired its interest in Rocky Road by writing down the value of the investment by approximately $20 million. NRG also recorded an impairment of $27 million on its investment in Saguaro. With the expiration of its gas supply contract, Saguaro began recording operating losses during the second half of 2005, triggering a permanent write down to NRG's investment value in Saguaro.

For the year ended December 31, 2004, NRG sold its Loy Yang investment, which resulted in a $1 million loss, the Company's interest in Commonwealth Atlantic Limited Partnership for a $5 million loss, and several NEO investments for a $4 million loss. These losses were offset by a $1 million gain associated with the sale of Calpine Cogeneration. Also during 2004, NRG recorded a $7 million impairment charge on its investment in James River LLC based on an estimated sale value from a prospective buyer.

Other Income, Net

For the year ended December 31, 2005, the Company's other income increased by $36 million as compared to the same period in 2004, to $58 million. Other income in 2005 was favorably impacted by a $14 million gain from the settlement related to the Company's TermoRio project in Brazil and a gain of approximately $4 million related to the resolution of a contingency from the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. Other income in 2005 was also favorably impacted by $14 million of higher interest income related to more efficient management of the Company's cash balances. These favorable results were offset by a $3 million reserve relating to the ongoing TermoRio litigation.

Refinancing Expenses

Refinancing expenses for the years ended December 31, 2005 and 2004 were $65 million and $72 million, respectively. During 2005, as part of the Company's continuing effort to manage its capital structure, NRG redeemed and purchased a total of $645 million of its second priority notes. As a result of the redemption and purchases, the Company incurred $55 million in premiums and write-offs of deferred financing costs. NRG also incurred an additional $11 million in refinancing fees during 2005 related to the amortization of a bridge loan commitment fee that the Company paid related to the acquisition of Texas Genco LLC.

As part of the Company's financing in connection with the acquisition of Texas Genco LLC, NRG paid a bridge loan commitment fee of approximately $45 million to ensure that the Company would have the proper financing in place for the acquisition. This amount was amortized over time, and during 2005 NRG amortized approximately $11 million to refinancing expense. The remaining balance of this amount was expensed during the first quarter of 2006 as the Company finalized the financing related to the acquisition of Texas Genco LLC.

For the year ended December 31, 2004, NRG refinanced certain amounts of the Company's term loans with additional corporate level debt on better terms, which resulted in $15 million of prepayment penalties and a $15 million write-off of deferred financing costs. Additionally, NRG refinanced its Senior Credit Facility in December 2004 and recorded $14 million of prepayment penalties and a $27 million of write-off related to the Company's deferred financing costs.

Interest Expense

Interest expense for the year ended December 31, 2005 was $184 million as compared to $255 million for the same period in 2004, a reduction of $71 million. Interest expense was favorably impacted by the sale of the Kendall facility, which incurred $25 million of interest expense for the year ended December 31, 2004. Additionally, the refinancing of the Company's Senior Credit Facility on December 23, 2004, lowered the interest related to the Facility by 212.5 basis points. In addition, the redemption and purchases of $645 million of the Company's second priority notes during 2005 reduced interest expense on the Company's corporate debt by approximately $50 million.

Income Tax Expense

Income tax expense was approximately $47 million and $74 million for the years ended December 31, 2005 and 2004, respectively. The overall effective tax rate was 39.5% and 32.3% for the years ended December 31, 2005 and 2004, respectively. The effective income tax rate for the years ended December 31, 2005 and 2004 differ from the U.S. statutory rate of 35% due to the Company's earnings in foreign jurisdictions, which are taxed at rates lower than the U.S. statutory rate. NRG's 2005 domestic effective income tax increased due to the gain on the sale of the Company's Enfield investment and the taxable dividend received pursuant to the American Job Creation Act of 2004.

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

Income from Discontinued Operations, Net of Income Tax Expense

For the years ended December 31, 2005 and 2004, NRG recorded income from discontinued operations, net of income taxes of approximately $12 million and $31 million, respectively, as the Company continued to divest certain non-core assets. Discontinued operations for the year ended December 31, 2005 consist of Flinders, Audrain, Resource Recovery, the Northbrook New York and Northbrook Energy assets and various expenses related to the final settlements of McClain. For the year ended December 31, 2004, discontinued operations consisted of the results of Flinders, Audrain, Resource Recovery, the two Northbrook entities, McClain, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). With the exception of Flinders, Audrain, Resource Recovery, Northbrook New York and Northbrook Energy, all discontinued operations were sold prior to December 31, 2004.

Results of Operations — Regional Discussions

Texas Region

The following table provides selected financial information for the Texas region for the period ended December 31, 2006.

	Period Ended December 31, 2006 (b) (In millions except otherwise noted)
Operating Revenues	
Energy revenue	$ 1,726
Capacity revenue	849
Risk Management Activities	(30)
Contract amortization	609
Hedge Reset	(129)
Other revenues	63
Total operating revenues	3,088
Operating Costs and Expenses	
Cost of energy	1,276
Depreciation and amortization	413
Other operating expenses	518
Operating Income	$ 881
MWh sold (in thousands)	46,361
MWh generated (in thousands)	44,910
Business Metrics	
Average on-peak market power prices ($/MWh)	$ 60.96
Cooling Degree Days, or CDDs(a)	2,891
CDD's 30 year rolling average	2,435
Heating Degree Days, or HDDs(a)	1,476
HDD's 30 year rolling average	1,694

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

(b) For the period February 2, 2006 to December 31, 2006 only.

Operating Income

For the year ended December 31, 2006, operating income for the Texas region was $881 million. A strong operating performance from the region's fleet contributed to these results, with the region's generating capacity operating at 90.7% availability, including baseload availability of 91.6%. Total generation for the year was approximately 45 million MWh, of which 74% were sold under long-term agreements, with total generation sold of approximately 46 million MWh. The difference between MWh sold and MWh generated represents MWh purchased from the marketplace. In August 2006, ERCOT set a new record for peak demand of 63,056 MWh on August 17, which the region's baseload and gas assets met. The strong operating performance was partially offset by approximately $135 million in losses associated with the Company's Hedge Reset transaction.

Operating Revenues

Total operating revenues from the Texas region for the year ended December 31, 2006 were approximately $3,088 million. Operating revenues included $1,726 million in energy revenues, of which 73% were contracted. Capacity revenues totaled $849 million, of which $343 million was related to capacity sales from the Company's investment in the STP nuclear generation facility. In addition, the region recorded $609 million of contract amortization revenues. For a further discussion on NRG's Hedge Reset transaction, see the *Consolidated Results of Operations* and Item 15 — Note 6, *Accounting for Derivative Instruments and Hedging Activities.*

Risk Management Activity — The total derivative loss for the year ended December 31, 2006 was $30 million, which was comprised of $152 million in losses associated with the settled positions of gas swaps, which were offset by $28 million in gains related to hedge accounting ineffectiveness due to a change in the correlation between natural gas and power prices, as well as $94 million in gains representing the change in the fair value of forward sales of electricity.

Cost of Energy

Cost of energy for the Texas region was approximately $1,276 million for the year ended December 31, 2006. Coal and lignite costs were $473 million for the year, gas fuel costs were $545 million and nuclear fuel-related expenses were $56 million. These costs directly relate to the generation from the Texas region's coal-fired, gas-fired and nuclear-fired units. Coal costs included $113 million of lignite coal used at the region's Limestone coal plant. Also included in cost of energy was an emissions allowance expense of $39 million, purchased power of $69 million, and $85 million in cost contract amortization.

Other Operating Expenses

Other operating expenses for the Texas region for the year ended December 31, 2006 were $518 million, or 17% of the region's total operating revenues. These costs include $335 million of operating and maintenance expenses of which 53% represents normal and major maintenance expenses. The $177 million of normal and major maintenance expenses was comprised of $80 million related to spring and fall planned outages at the region's W.A. Parish and Limestone plants. Due to these outages, both plants gained capacity via uprates. The region's gas plants also incurred approximately $31 million in maintenance costs related to outages, while STP incurred approximately $66 million in maintenance costs, primarily related to refueling outages. The Texas region also recorded approximately $57 million in property tax expense. In addition, the Texas region incurred $125 million of G&A expense, of which $50 million was related to corporate allocations and $14 million related to development cost in support of the region's *Repowering NRG* program.

Northeast Region

2006 compared to 2005

The following table provides selected financial information for the Northeast region for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 966	$ 1,444	(33)%
Capacity revenue	321	291	10
Risk Management Activities	144	(285)	N/A
Other revenues	112	104	8
Total operating revenues	1,543	1,554	—
Operating Costs and Expenses			
Cost of energy	615	869	(29)
Depreciation and amortization	89	74	20
Other operating expenses	378	393	(4)
Operating Income	$ 461	$ 218	111
MWh sold (in thousands)	13,309	16,246	(18)
MWh generated (in thousands)	13,309	16,246	(18)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 71.55	$ 91.98	(22)
Cooling Degree Days, or CDDs(a)	653	801	(18)
CDD's 30 year rolling average	537	537	—
Heating Degree Days, or HDDs(a)	5,417	6,162	(12)%
HDD's 30 year rolling average	6,261	6,261	—

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

Operating Income

For the year ended December 31, 2006, operating income for the Northeast region was $461 million, compared to $218 million for the same period in 2005, an increase of $243 million. This increase was due to $144 million in mark-to-market gains from risk management activities, compared to a $285 million loss for the year ended December 31, 2005. The favorable gain from risk management activities was largely due to weak forward power prices, which resulted in substantial unrealized gains in the region's forward positions for the year ended December 31, 2006. Power prices were weaker in 2006 relative to 2005, driven by gas price volatility following Hurricanes Rita and Katrina in 2005, and a mild winter in January, February and December. The mild weather reduced demand for natural gas, with average prices falling as much as 22% year over year. Falling natural gas prices reduced annual average power prices in the New York, NEPOOL and PJM markets by 23%, 20% and 19%, respectively. The mild weather also led to an 18% decline in power generation for the Company's Northeast region to 13.3 million MWh in 2006, compared to 16.2 million MWh in 2005. Declines in generation from the region's oil-fired assets declined by nearly 2 million MWh, representing 66% of the overall Northeast region's generation decrease. Half of this decline was attributable to the region's Western New York plants, which had more run time in 2005 due to that year's cold January winter.

Total Operating Revenues

Total operating revenues from NRG's Northeast region totaled $1,543 million for the year ended December 31, 2006, compared to $1,554 million for the same period in 2005, a decrease of $11 million. Revenues for the year ended December 31, 2006 included $966 million in energy revenues, compared to $1,444 million for the same period in 2005, a decrease of $478 million. Of this $478 million decrease, $318 million can be attributed to the region's New York assets, which reflect lower generation from the region's Oswego plant and lower realized price from generation from the region's baseload coal plants. In addition, the region had $23 million of adjustments in 2005 relating to prior year NYISO settlements and a $6 million reversal of a reserve due to a favorable court decision regarding spinning reserve payments.

Capacity revenues for the year ended December 31, 2006 were $321 million, compared to $291 million for the same period in 2005. Of this increase, $28 million was due to higher capacity revenues in the New York State market. New York capacity revenues outside of New York City drove the increase in 2006, as increased demand for capacity, coupled with a decline in imports of capacity into the market, pushed clearing prices higher. Capacity prices were also favorably impacted in the region's New England market by $16 million due to the new LFRM market and the new transition capacity market. The Northeast region also earned $9 million more in RMR payments in 2006 with the approval of new RMR agreements. These were partially offset by $23 million of reserve reversals in 2005 following the settlement of prior year RMR agreements.

Other revenues which include emission allowance sales, natural gas sales, and expense recovery revenues, totaled $112 million for the year ended December 31, 2006, compared to $104 million in the same period in 2005, an increase of $8 million. This increase was primarily related to $17 million in higher emission allowance sales as the Company sold emission allowances in lieu of generation during the first quarter 2006. Higher emission allowance revenues were partially offset by lower gas sales of $2 million, lower ancillary revenues of $3 million and lack of cost recovery revenues of $5 million related to the 2005 RMR agreements.

Risk Management Activity — The total derivative gain for the year was $144 million, comprised of $10 million in financial revenue losses and $154 million of unrealized mark-to-market gains. The $10 million loss of financial revenues represents the settled value for the year of all financial instruments, including financial swaps and options on power. Of the $154 million of mark-to-market gains, $50 million represented the fair value of forward sales of electricity and fuel transactions to support the region's physical asset position, with $14 million of mark-to-market losses related to trading activity. In addition, $90 million represented the reversal of mark-to-market losses, which ultimately settled as financial revenues. In 2005, the total derivative loss was $285 million comprised of $132 million in financial revenue losses and $153 million mark-to-market losses.

Hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold. The changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and cost of energy. Thus, while the 2006 decrease in electricity prices adversely impacted the region's generation portfolio compared to the prior year, it was also favorably impacted by positive mark-to-market gains on the region's forward sales and the settlement of positions as smaller losses as compared with the prior year.

Cost of Energy

Cost of energy was $615 million for the year ended December 31, 2006. This was a decrease of $254 million compared to the same period in 2005. The decrease was primarily attributable to an 18% decline in generation from the region's generation assets. Oil fuel costs in the Northeast region decreased by $143 million, as the decline in oil-fired generation accounted for 66% of the total decline in generation volume. Gas fuel costs for the Northeast region decreased by $101 million. Coal costs increased by $11 million, despite slightly lower generation, primarily due to higher rail transportation costs. Emission allowance amortization costs declined in 2006 by $18 million, primarily due to lower generation, which resulted in lower consumption of emission allowances.

Other Operating Expenses

Other operating expenses for the Northeast region were $378 million for the year ended December 31, 2006, a decrease of $15 million compared to the same period in 2005. Maintenance expense increased by $15 million in 2006 primarily due to more extensive boiler tube work at the region's Dunkirk and Arthur Kill plants to reduced forced outage hours and additional turbine maintenance and oil tank repair costs at the region's Oswego facility. Offsetting higher maintenance cost, was a decrease in plant utilities by $20 million. This was primarily due to a favorable court decision in the second quarter 2006 that allowed the Northeast region to reverse into earnings $18 million of previously accrued station power expense. General and administrative costs decreased by $10 million in 2006, primarily due to increased personnel and external consulting costs incurred to advance the region's *Repowering NRG* program. During 2006, the Northeast region incurred $8 million in expenditures to advance its regional redevelopment efforts. This increase was offset by $8 million in lower insurance costs and $14 million in lower corporate allocation.

2005 compared to 2004

The following table provides selected financial information for the Northeast region for the years ended December 31, 2005 and 2004:

	Year Ended December 31, 2005	Year Ended December 31, 2004	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 1,444	$ 853	69%
Capacity revenue	291	265	10
Risk Management Activities	(285)	58	NA
Contract amortization	—	(6)	NA
Other revenues	104	81	28
Total operating revenues	1,554	1,251	24
Operating Costs and Expenses			
Cost of energy	869	521	67
Depreciation and amortization	74	73	1
Other operating expenses	393	339	16
Operating Income	$ 218	$ 318	(31)
MWh sold (in thousands)	16,246	14,259	14
MWh generated (in thousands)	16,246	14,259	14
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 91.98	$ 63.53	45
Cooling Degree Days, or CDDs(a)	801	516	55
CDD's 30 year rolling average	537	537	—
Heating Degree Days, or HDDs(a)	6,162	6,157	—
HDD's 30 year rolling average	6,261	6,294	(1)%

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

Operating Income

For the year ended December 31, 2005, operating income for the Northeast region was $218 million, compared to $318 million for the same period in 2004, a decrease of $100 million. This decrease was primarily due to $121 million net mark-to-market losses reported by the Northeast associated with forward sales of electricity, compared to a $59 million net mark-to-market gain recorded in 2004. Excluding mark-to-market losses, the Northeast region's operating income increased by $21 million. This increase was largely due to increased power prices, wider dark spread margins, and increased generation from the region's gas- and oil-fired assets. With higher than average temperatures in the summer of 2005, on-peak electricity prices increased 43% to 52% compared to 2004, while gas and oil prices increased 50% and 49%. Spark spreads on the region's gas and coal margins widened, while oil margins were compressed compared to the same period in 2004. The Northeast region's New York City assets benefited from increased spark spreads and with increased generation output, by 53% compared to 2004, from 1.1 million MWh to 1.7 million MWh, due to increased summer demand. Generation from the Northeast region's oil-fired assets increased by 120%, but oil margins decreased by 25% compared to 2004, as cost per MWh increased by 29% in comparison to the same period in 2004, due to an offsetting increase in oil prices.

Total Operating Revenues

Total operating revenues from the Northeast region totaled $1,554 million for the year ended December 31, 2005 compared to $1,251 million for the same period in 2004, an increase of $303 million. Revenues for the year ended December 31, 2005 included $1,444 million in energy revenues compared to $853 million for the same period in 2004. Of this $591 million increase, $183 million can be attributed to the region's New York City assets. Due to outages of local competitors and extreme summer heat, generation from the region's New York City assets increased by 53% for the year ended December 31, 2005, compared to the year ended December 31, 2004. Excluding $23 million of final NYISO settlement payments, increased generation accounted for 49% of the increase in New York City energy revenues. The region's oil-fired assets earned $211 million more in energy revenues due to increased generation by 120% during 2005 compared to 2004; 86% of the increase in energy revenues was due to increased generation. The region's coal assets recorded higher energy revenues of $99 million, primarily due to higher power prices as generation from the region's coal assets had a minimal decrease for the year ended December 31, 2005.

Capacity revenues for the year ended December 31, 2005 were $291 million, compared to $265 million for the same period in 2004. Capacity revenues were favorable compared to the previous year due to $24 million of additional capacity revenues recorded during the second quarter of 2005 in connection with the region's Connecticut RMR settlement agreement approved by FERC on January 22, 2005. These settlement revenues were offset, however, by lower capacity revenues from the region's western New York plants. Capacity prices in western New York were negatively impacted by the addition of new capacity supply and increased imports into the state.

Other revenues which include emission allowance sales, natural gas sales and expense recovery revenues, totaled $104 million for the year ended December 31, 2005 compared to $81 million for the year ended 2004, an increase of $23 million. This increase was related to $43 million in emission allowance sales and $6 million in higher gas sales. These increases were partially offset by $29 million in lower expense recovery revenues related to the Connecticut RMR agreement. The region reached its maximum payment under that agreement during the first quarter of 2005.

Risk Management Activity — The total derivative loss for the year ended December 31, 2005 was approximately $285 million, comprised of $132 million in financial revenue losses and $153 million of mark-to-market losses. The $132 million loss in financial revenues represented the settled value for the year of financial instruments that do not qualify for hedge accounting treatment. Of the $153 million of mark-to-market losses, $121 million represented the change in fair value of forward sales of electricity and fuel, $59 million represented the reversal of mark-to-market gains, which ultimately settled as financial revenues, and $27 million in gains were associated with trading activities.

Since hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. In the fourth quarter of 2004 and over the course of 2005, NRG hedged much of its calendar year 2005 and 2006 Northeast region's generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions this summer. While this increase in electricity prices benefited the region's generation portfolio compared to the prior year with higher energy revenues, it was also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

Cost of Energy

Cost of energy increased by $348 million for the Northeast region for the year ended December 31, 2005 to $869 million, compared to the same period in 2004. Oil fuel costs in the region increased by $162 million, where 65% of the increase was due to increased generation with the region's gas fuel costs increasing by $129 million. Higher gas sales from the region's New York City assets drove $15 million of the increase, with $109 million of the increase related to higher prices and demand for the region's New York City assets. Coal costs increased by $61 million, due to increased prices, although the region's coal-fired generation had a minimal decrease during 2005 compared to 2004, specifically due to scheduled and unplanned outages at the region's western New York and Indian River facilities during the second and fourth quarters 2005. Of the $61 million increase in coal cost, 71% was due to increases at the region's Indian River plant. The region's Indian River plant used a higher portion of eastern coal, whose price experienced a significant increase during 2005.

Other Operating Expenses

Other operating expenses for the Northeast region increased by $54 million for the year ended December 31, 2005 compared to the same period in 2004. This increase was driven by operating and maintenance costs, led by higher major maintenance costs. The low-sulfur conversion projects continued at the region's western New York plants and began at its Indian River plant this year, and major outages related to turbine overhauls also took place at the region's western New York and Indian River plants. The increased number and scope of the outages contributed to the $14 million increase in major maintenance expense this year. Additionally, in 2004, a settlement with a third party vendor regarding auxiliary power charges reduced 2004 operating and maintenance expenses by $7 million.

Other operating expenses for the Northeast region included administrative regional office costs, other non-income tax expense, insurance and corporate allocations. These costs increased by $30 million in 2005 compared to 2004, $14 million of which was due to non-income tax expense, as the region recognized property tax credits in 2004. The remainder of the increase was primarily due to regional office and corporate allocations.

South Central Region

2006 compared to 2005

The following table provides selected financial information for the South Central region for the years ended December 31, 2006 and 2005:

	Year ended December 31, 2006	Year ended December 31, 2005	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 334	$ 339	(1)%
Capacity revenue	199	190	5
Risk Management Activities	13	(2)	N/A
Contract Amortization	19	9	111
Other revenues	5	24	(79)
Total operating revenues	570	560	2
Operating Costs and Expenses			
Cost of energy	308	374	18
Depreciation and amortization	68	67	1
Other operating expenses	89	111	(20)
Operating Income	$ 105	$ 8	N/A
MWh sold (in thousands)	11,845	11,771	1
MWh generated (in thousands)	11,036	10,009	10
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 56.29	$ 69.96	(20)
Cooling Degree Days, or CDDs[(a)]	2,908	2,826	3
CDD's 30 year rolling average	2,449	2,449	—
Heating Degree Days, or HDDs[(a)]	1,815	2,016	(10)%
HDD's 30 year rolling average	2,287	2,287	—

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

Operating Income

The South Central region realized operating income of $105 million for the year ended December 31, 2006 compared to operating income of $8 million for the same period in 2005, an increase of $97 million. The increase in operating income was primarily driven by better plant availability due to lower planned and forced outages in 2006, which resulted in 11% higher coal generation in 2006 than 2005. The Big Cajun II facility achieved an EFOR of 3.13% in 2006 compared to 6.56% in 2005, resulting in 907 fewer forced outage hours in 2006. In addition, the Big Cajun II coal units experienced 826 less planned outage hours in 2006 than in 2005. The forced outages in 2005 occurred primarily during the peak summer months when contract load is highest, requiring increased energy purchases than in 2006. These fewer planned outages in 2006 also resulted in $12 million of lower major maintenance expense, which benefited operating income. Favorable price spreads in 2006 allowed for resale of power received from the region's tolling agreements, providing additional margins.

Total Operating Revenues

Operating revenues increased by $10 million in 2006 compared to 2005. Increased sales to the region's contract customers were offset by lower sales in the merchant market. Capacity revenues were $9 million higher for the year ended December 31, 2006 than in the same period for 2005, as the peak of 2011 MW set by the region's cooperative customers in August 2006 impacted capacity revenue in the latter half of 2006. The South Central region also recognized $13 million from risk management activities in 2006. Contract amortization increased by $10 million due to increased megawatt hour sales to contract customers and the expiration of the Rockford contract in 2005. Other revenues declined by $19 million from 2005 levels, primarily due to $23 million in lower gas sales relating to the region's tolling agreements.

Cost of Energy

Cost of energy for the South Central region was $308 million for the year ended December 31, 2006, compared to $374 million for the same period in 2005, a decrease of $66 million. Coal costs for the region increased by $25 million, reflecting contractual increases in coal commodity costs and higher plant availability in 2006. As a result of improved plant availability, energy purchased by the South Central region to support load contracts dropped 16%. The cost of purchased power, including the costs of the region's tolling agreements, was $74 million in 2006, a decrease of $71 million from 2005. This decrease was primarily due to fewer forced outages at the region's baseload coal plants in 2006 and the impact of netting energy purchases and resale. A drop in average purchased power prices by $9/MWh from 2005 to 2006 also contributed to the reduction in purchased power costs. The South Central region increased its use of generation from tolled facilities in 2006; tolled combined cycle plants contributed 1,451,758 MWh to the region's energy resources in 2006 compared to 474,386 MWh in 2005. The tolling agreements further contributed to the region's results as the spread between gas costs and energy costs widened in the summer of 2006. Transmission costs increased by $7 million due to a combination of contractual increases in network transmission rates and higher peaks in 2006.

Other Operating Expenses

Other operating expenses for the South Central region for the year ended December 31, 2006 was $89 million, a reduction of $22 million compared to the year ended December 31, 2005. The reduction was primarily due to lower major maintenance costs, which dropped by $12 million due to fewer planned outages at the region's coal plant in 2006 and lower insurance costs, which were $3 million less in 2006 due to lower premiums.

2005 compared to 2004

The following table provides selected financial information for the South Central region for the years ended December 31, 2005 and 2004:

	Year Ended December 31, 2005	Year Ended December 31, 2004	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 339	$ 221	53%
Capacity revenue	190	211	(10)
Risk Management Activities	(2)	—	N/A
Contract Amortization	9	—	N/A
Other revenues	24	2	N/A
Total operating revenues	560	434	29
Operating Costs and Expenses			
Cost of energy	374	224	67
Depreciation and amortization	67	69	(3)
Other operating expenses	111	80	39
Operating Income	$ 8	$ 61	(87)
MWh sold (in thousands)	11,771	10,613	11
MWh generated (in thousands)	10,009	10,361	(3)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 69.96	$ 45.76	53
Cooling Degree Days, or CDDs(a)	2,826	2,550	11
CDD's 30 year rolling average	2,449	2,449	—
Heating Degree Days, or HDDs(a)	2,016	2,043	(1)%
HDD's 30 year rolling average	2,287	2,287	—

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

Operating Income

For the year ended December 31, 2005, the South Central region realized operating income of $8 million, compared to $61 million for the year ended December 31, 2004. During 2005, the region's Big Cajun II facility experienced several forced outages during the summer months, at which time contract demand and replacement power costs were at their highest. Generation for 2005 decreased by 3% from 10.3 million MWh to 10 million MWh compared to the same period in 2004, with 0.2 million MWh lost due to forced outages. These outages contributed to the purchase of $114 million in additional purchased energy required to meet contract load- following obligations in the merchant market at costs higher than the region's coal-based generation assets. In addition, during 2005, South Central had three planned outages compared to one major planned outage during 2004, which increased major maintenance by $20 million, as compared to the year ended December 31, 2004.

Total Operating Revenues

Total operating revenues from the South Central region were $560 million for the year ended December 31, 2005 compared to $434 million for the same period in 2004, an increase of $126 million. Revenues for the year ended December 31, 2005 included $339 million in energy revenues, of which 61% was contracted. This compares to $221 million of energy revenues for the year ended December 31, 2004, 73% of which was contracted. The increase of $118 million in energy revenues and the lower percentage contracted was due to increased merchant energy sales following higher power prices, favorable weather, and nuclear plant outages in the region. Also, a round-the-clock 100 MW sale to Entergy and a tolling agreement, which at times provided power that could be resold at a higher price, helped to increase merchant revenues. Other revenues primarily include physical gas sales. For the year ended December 31, 2005, other revenues totaled $24 million compared to $2 million for the year ended December 31, 2004, with the increase due to $23 million in physical gas sales related to a new gas sale agreement entered into in July 2005. NRG entered into this agreement in conjunction with power purchase agreements to minimize the South Central region's market purchases during peak months.

Cost of Energy

The South Central region's cost of energy increased by $150 million for the year ended December 31, 2005, compared to the same period in 2004. Of this amount, $114 million was due to higher purchased energy costs. During 2005, the region's Big Cajun II facility experienced a number of forced outages, encountered high demand from the region's long-term contracts, and entered into 100-MW around-the-clock sale to Entergy, and a tolling agreement, all of which required the purchase of energy to meet contract load obligations. Purchased energy per MWh increased by 365% versus the same period in 2004. In addition, due to the extreme weather conditions and increased gas prices, the average purchased energy price increased $19 per MWh for the year ended December 31, 2005, compared to the same period in 2004.

Other Operating Expenses

Other operating expenses increased by $31 million for the year ended December 31, 2005, compared to the same period in 2004, with $20 million of the increase primarily related to major maintenance due to increased planned and unplanned outages at the region's Big Cajun II facility, and $12 million related to the regional office expenses and corporate allocations.

West Region

The following table provides selected financial information for the West region for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 75	$ 1	$ 10
Capacity revenue	68	—	(4)
Risk Management Activities	(3)	—	—
Contract Amortization	—	—	(3)
Other revenues	6	3	4
Total operating revenues	146	4	7
Operating Costs and Expenses			
Cost of energy	80	1	5
Depreciation and amortization	3	1	1
Other operating expenses	55	8	9
Operating Income/(loss)	$ 8	$ (6)	$ (8)
MWh sold (in thousands)	1,901	6	77
MWh generated (in thousands)	1,901	6	77
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 60.12	$ 71.06	$ 53.16
Cooling Degree Days, or CDDs(a)	926	775	887
CDD's 30 year rolling average	704	704	704
Heating Degree Days, or HDDs(a)	3,001	2,842	2,826
HDD's 30 year rolling average	3,228	3,228	3,243

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

Operating Income

For the year ended December 31, 2006, operating income for the West region was approximately $8 million, compared to a loss of $6 million for the year ended December 31, 2005. For the year ended December 31, 2004, the West region recorded an operating loss of $8 million primarily due to higher cost of energy and other operating expenses. The 2006 gain in operating income was primarily due to NRG's acquisition of Dynegy's 50% interest of WCP. The California high-voltage power grid handled an all time record peak demand on July 24, 2006 at 50,270 MW, with the previous record peak demand of 45,431 MW set on July 20, 2005.

Total Operating Revenues

Total operating revenues for the year ended December 31, 2006 were $146 million, comprised of $75 million in energy revenues, of which 39% were contracted, and $68 million in capacity revenues. This compares to $4 million in operating revenues, comprised of $1 million in energy revenues and $3 million in other revenues for the year ended December 31, 2005. For the year ended December 31, 2004, total operating revenues for the West region was $7 million, primarily comprised of energy revenues.

Cost of Energy

Cost of energy for the year ended December 31, 2006, was approximately $80 million, consisting primarily of gas costs. For the year ended December 31, 2005, cost of energy for the West region was $1 million and $5 million for the year ended December 31, 2004.

Other Operating Expenses

Operating expenses for the West region for the year ended December 31, 2006 were $55 million, or 38% of the region's total operating revenues. These costs included $32 million in operating and maintenance costs, of which $10 million was related to normal maintenance expenses associated with outage work. The region also incurred approximately $19 million in G&A expenses, of which $4 million was related to development costs associated with the Company's *Repowering NRG* program and approximately $3 million in corporate allocations. The increase was primarily due to the consolidation of WCP, development spending, and NRG cost allocations. This compares to $8 million and $9 million for the years ended December 31, 2005 and 2004, respectively.

Liquidity and Capital Resources

Significant Events during 2006

Acquisitions and Dispositions

- The acquisition of Texas Genco LLC for $6.2 billion, including the assumption of approximately $2.7 billion in debt.
- Proceeds of approximately $357 million and an after-tax gain of approximately $75 million recognized from the sale of Flinders and Audrain.
- Proceeds of approximately $109 million from the sale of non-core assets.
- The purchase of the remaining 50% interest in WCP and sale of NRG's 50% interest in Rocky Road for a net $160 million.

Financings and Operations

- The issuance of $5.6 billion in a senior credit facility, including a $1 billion revolving credit facility and a $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 related to the acquisition of Texas Genco LLC.
- The extinguishment of $1.1 billion in aggregate principal amount of NRG's 8% second priority notes.
- The extinguishment of $1.1 billion in aggregate principal amount of Texas Genco LLC and Texas Genco Financing Corp.'s 6.875% senior notes.
- The issuance of $1.1 billion in unsecured high yield notes and an increase by $500 million in the existing synthetic letter of credit facility related to the Hedge Reset transaction in November 2006.
- The institution of a Capital Allocation Program announced on August 1, 2006.
  - Phase I consisted of the issuance of approximately $249 million of notes and $84 million of preferred interest by unrestricted subsidiaries to partially fund the purchase of $500 million of NRG common stock completed in the fourth quarter 2006.
  - Phase II, also a $500 million share buyback, is expected to be completed in the first half of 2007, of which 4.2 million shares of NRG common stock had been repurchased as of December 31, 2006.
  - Completed the repayment of $400 million in debt as part of Phase II.
- The termination of NRG term loan, funded letter of credit and revolving credit facilities issued on December 24, 2004.
- The return of cash collateral payments of $454 million due to decreases in forward prices for natural gas and power as well as the settlement of trades.

Liquidity Position

As of December 31, 2006, NRG's liquidity was approximately $2.2 billion and included approximately $839 million of unrestricted and restricted cash. NRG's liquidity also included $855 million of borrowing capacity under the Company's revolving credit facility, and $533 million of availability under the Company's letter of credit facility. As of December 31, 2005, NRG's liquidity was $758 million and included $570 million of unrestricted and restricted cash. The Company's year-end liquidity also included $150 million of available capacity under the Company's revolving line of credit and $38 million of availability under the Company's letter of credit facility.

Credit Ratings

Credit-rating agencies rate the Company's public debt securities. These ratings are utilized by the debt markets in evaluating a firm's credit risk. Ratings influence the price paid to issue new debt securities by indicating to the market NRG's ability to pay principal, interest, and preferred dividends. Rating agencies evaluate a firm's industry, cash flow, leverage, liquidity, and hedge profile, among other factors, in their credit analysis of a firm's credit risk.

The following table summarizes the credit ratings for NRG Energy, Inc., its term loan and its senior notes as of December 31, 2006:

	S&P	Moody's	Fitch
NRG Energy, Inc.	B+	Ba3	B
7.375% Senior Notes, due 2016, 2017	B−	B1	B+
Senior Notes 7.25%	B−	B1	B+
Term Loan	BB−	Ba1	BB

In November 2006, in connection with the Company's Hedge Reset transaction, all three agencies reviewed NRG's ratings and took the following actions:

- Moody's reaffirmed their rating but modified NRG's outlook to negative, reflecting their view of the increased debt level at NRG associated with the program;
- Standard & Poor's reaffirmed their rating with a stable outlook; and
- Fitch reaffirmed their rating with a stable outlook.

SOURCES OF FUNDS

The principal sources of liquidity for NRG's future operating and capital expenditures were derived from new financing arrangements, asset sales, existing cash on hand and cash flows from operations.

Financing Arrangements

Texas Genco LLC Acquisition Related Financing — To finance the acquisition of Texas Genco LLC, NRG received: (i) cash proceeds of approximately $1 billion upon the issuance and sale in a public offering of 20,855,057 shares of NRG common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $1.2 billion aggregate principal amount of 7.25% Senior Notes due 2014 and $2.4 billion aggregate principal amount of 7.375% Senior Notes due 2016; (iii) cash proceeds received upon the issuance and sale in a public offering of 2 million shares of mandatory convertible preferred stock at a price of $250 per share; and (iv) funds borrowed under a 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.

Hedge Reset Transaction Related Financing — To finance NRG's Hedge Reset transactions, the Company received $1.1 billion upon the sale of 7.375% Senior Notes due 2017. In addition, NRG amended the Company's existing Senior Credit Facility, which resulted in an increase of the synthetic letter of credit facility by $500 million to $1.5 billion. The amendment revised certain terms within the existing credit agreement to provide greater financial flexibility to the Company, including increasing NRG's restricted payment basket, which effectively governs the Company's ability to return capital to shareholders. As part of the amendment of the Company's Senior Credit Facility, NRG inserted a provision that results in an increased level of mandatory first lien debt repayment each year. Beginning in 2008, NRG must offer a portion of its excess cash flow, an amount that approximates the Company's free cash flow for the prior year, to its first lien lenders. The percentage of the excess cash flow offered to these lenders is dependent upon the Company's consolidated leverage ratio at the end of the preceding year. Of the amount offered, the first lien lenders must accept 50%, while the remaining 50% may either be accepted or rejected at the lenders' option.

Capital Allocation Program — In connection with NRG's share repurchase program, the company issued notes and preferred interest in the aggregate amount of $249 million and $84 million, respectively, to Credit Suisse through two wholly-owned unrestricted subsidiaries of NRG.

Asset Sales

Red Bluff and Chowchilla — On January 3, 2007, NRG completed the sale of the Red Bluff and Chowchilla II power plants to an entity controlled by Wayzata Investment Partners LLC. These power plants, located in California, are fueled by natural gas with generating capacity of 45 MW and 50 MW, respectively.

Resource Recovery — On November 8, 2006, NRG completed the sale of the Company's Newport and Elk River Resource Recovery facilities, Becker Ash Disposal facility, as well as the Company's ownership interest in NRG Processing Solutions LLC, to Resource Recovery Technologies, LLC for total proceeds of approximately $22 million.

Australia — On August 30, 2006, NRG announced the completion of the sale of its 100% owned Flinders power station and related assets or Flinders, located near Port Augusta, Australia, to Babcock & Brown Power Pty, a subsidiary of Babcock & Brown, a global investment and advisory firm. Proceeds from the sale were approximately $242 million (AU$317 million). The sale resulted in the elimination of approximately $370 million (AU$485 million) of consolidated liabilities, including approximately $183 million (AU$240 million) of non-recourse debt obligations and approximately $92 million (AU$121 million) in non-current liabilities related to the obligations for the purchase of electricity and the supply of fuel to the Osborne power station that were guaranteed by NRG. NRG recognized an after-tax gain of approximately $60 million from the sale.

Rocky Road — On March 31, 2006, in conjunction with NRG's purchase of Dynegy's 50% interest in WCP, NRG sold the Company's 50% interest in Rocky Road to Dynegy as part of the Company's purchase and sale agreement with Dynegy for a sale price of $45 million. There was no gain or loss on the sale due to the fact that in 2005, NRG recorded an impairment charge of approximately $20 million to write down the value of NRG's 50% interest in Rocky Road to its fair value of $45 million.

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

USES OF FUNDS

The Company's requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (1) Acquisitions; (2) Commercial Operations activities; (3) capital expenditures; (4) corporate financial transactions such as share repurchases; and (5) debt service obligations.

Acquisitions

Texas Genco LLC — 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. The value of NRG's common stock issued to the Sellers was based on the Company's average stock price immediately before and after the closing date of February 2, 2006. The acquisition also included the assumption of approximately $2.7 billion of Texas Genco LLC debt. In connection with the acquisition, NRG substantially revised its financial structure.

West Coast Power Holdings, Inc. On March 31, 2006, NRG completed purchase and sale agreements for projects co-owned with Dynegy, Inc., or Dynegy. Under the agreements, NRG acquired Dynegy's 50% ownership interest in WCP (Generation) Holdings, LLC, or WCP, for $205 million and NRG became the sole owner of WCP's 1,825 MW of generation capacity in Southern California. In addition, NRG sold to Dynegy its 50% ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. NRG sold Rocky Road for a fair value sale price of $45 million, thus paying Dynegy a net purchase price of $160 million at closing.

Commercial Operations

Commercial Operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (1) margin and collateral posted with counter-parties; (2) initial collateral required to establish trading relationships; (3) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (4) initial collateral for large structured transactions. As of December 31, 2006, Commercial Operations had total cash collateral outstanding of $27 million, and $967 million outstanding in letters of credit to third parties primarily to support its economic hedging activities.

Future liquidity requirements may change based on the Company's hedging activities and structures, fuel purchases, and future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on NRG's credit ratings and general perception of its creditworthiness.

Collateral — In connection with the Company's power generation business, NRG manages the commodity price risk associated with the Company's supply activities and electric generation facilities. This includes forward power sales, fuel and energy purchases and emission allowances. In order to manage these risks, NRG enters into financial instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy. NRG utilizes a variety of instruments, including forward contracts, futures contracts, swaps and options. Certain contract counterparties require NRG to post margin collateral. As of February 21, 2007, NRG had posted $81 million in collateral to support these contracts.

Capital Expenditures

Capital expenditures were $221 million, $106 million and $119 million for the years ended December 31, 2006, 2005 and 2004, respectively. In 2006, approximately half of the $221 million in capital spending was in NRG Texas. Expenditures of $63 million are attributed to South Texas Project, mainly for nuclear fuel purchases and a turbine replacement, which resulted in an increase in capacity. The balance of the Texas spending was for major projects at the fossil plants, including environmental and uprate projects at Limestone, another major uprate project at W.A. Parish, combustion system work at San Jacinto and T.H. Wharton, and work at Jewett mine. Northeast capital spending of $50 million was mostly due to additional work at Huntley and Dunkirk related to the plants coal handling facilities, including $18 million largely for PRB coal conversion and reheater replacements at Indian River. A reliability improvement project at Big Cajun II and a transmission expansion project account for the majority of South Central expenditures of $11 million. In 2005, capital expenditures were related to PRB coal conversions, and associated conveyor track and emissions compliance upgrades at the Company's western New York plants and Indian River facility. Capital expenditures in 2004 also related primarily to the conversion of NRG western New York plants to PRB coal.

Environmental capital expenditures for the years ended December 31, 2006 and 2005 were approximately $11 million and $18 million, respectively. Based on current rules, technology and plans, NRG has estimated that approximately $1.28 billion of environmental capital expenditures will be incurred during the period 2007 through 2012, primarily related to installation of particulate, SO_2, NOx, and mercury controls to comply with the CAIR and Clean Air Mercury rules, as well as installation of BTA under the Phase II 316(b) Rule. NRG currently updates its estimates for environmental capital expenditures annually, and these estimates can be expected to change over time, in some cases materially. These plans are based on current regulatory requirements and best engineering practices. Changes to regulations or market conditions could result in changes to installed equipment timing or associated costs.

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

	Texas	Northeast	South Central	Other	Total
			(In millions)		
2007	$ 9	$ 118	$ 41	$ 9	$ 177
2008	16	183	93	10	302
2009	19	183	167	5	374
2010	26	144	84	4	258
2011	19	30	63	1	113
2012	13	3	33	—	49
Total	$ 102	$ 661	$ 481	$ 29	$ 1,273

NRG is working to reduce a portion of the above environmental capital expenditures through the Company's ability to monetize a portion of its excess allowances over the 2007-2012 timeframe and still hold sufficient allowances to operate the fleet with proposed controls through at least 2020. In addition, NRG's current contracts with the Company's rural electrical customers in the South Central region allow for recovery of a significant portion of the costs incurred by complying with new laws along with a capital return, including interest over the asset life of the required expenditures. Actual recoveries will depend, among other things, on the duration of the contracts and the treatment of these expenditures.

Corporate Financial Transactions

Hedge Reset and Extension — On November 21, 2006, NRG announced the completion of the Company's Hedge Reset transaction, which included (1) the net settlement of existing out-of-the-money hedges for the years 2006 through 2011 to market, (2) substantial new baseload hedges for the years 2010 through 2012 and, possibly, later years, (3) the issuance of $1.1 billion of new high yield notes, and (4) amendments to NRG's existing Senior Credit Facility, including the increase of the synthetic letter of credit facility by $500 million.

As part of the Hedge Reset transaction, NRG net settled certain existing hedge agreements for the years 2006 through 2010, including hedge agreements with J. Aron & Company. These hedges were gas swaps and power contracts that were acquired as part of the acquisition of Texas Genco LLC, which closed on February 2, 2006. These contracts were entered into by Texas Genco LLC at a time when power and natural gas prices were lower than they were at the time of the Hedge Reset, and as a result, the previous hedges obligated NRG to sell power or natural gas at prices significantly below current market prices. Under the amended agreements, NRG negotiated the pricing of these hedges to reflect prevailing market prices, and paid cash to the hedge counterparties in amounts that reflect a negotiated present value of the difference between the original prices in the hedges and the amended prices. The total amount paid to the counterparties was approximately $1.35 billion.

The Hedge Reset provided the Company's shareholders with a number of benefits. First, the Company has increased its cash flows that will be available to shareholders between 2007 and 2010 by approximately $1.5 billion. Second, it has afforded NRG the flexibility, through the Company's second lien structure, to expand the Company's hedges on baseload generation for the 2010-2012 periods, thus reducing the volatility in earnings and cash flow. Third, the Company obtained amendments of its Senior Credit Facility that has provided the Company the ability to return more capital to shareholders, as well as greater flexibility in the Company's *Repowering NRG* program.

Capital Allocation Program — During the third quarter 2006, NRG initiated a plan, known as the Capital Allocation Program, to repurchase approximately $750 million of its common stock. Phase I was a $500 million stock repurchase program, which was completed on October 13, 2006.

To implement Phase I, the Company formed two wholly-owned unrestricted subsidiaries to repurchase shares of NRG's common stock in the public markets or in privately negotiated transactions. These subsidiaries were funded with a combination of approximately $167 million in cash from NRG, together with the proceeds from the issuance of approximately $249 million in notes and approximately $84 million in preferred stock to Credit Suisse, for a total amount of approximately $500 million. Both the notes and the preferred interests will mature in two tranches: $137 million in notes and $53 million in preferred interests will mature in October 2008, and $112 million in notes and $31 million in preferred interests will mature in October 2009.

On October 13, 2006, NRG completed Phase I of the program, with total common stock repurchased of 10,587,700 common shares at an average price of $47.22 for approximately $500 million.

On November 24, 2006, NRG, as part of Phase II of the Company's Capital Allocation Program, announced an agreement to repurchase 4,212,881 shares of NRG common stock from affiliates of the Blackstone Group at a price of $55.00 per share. The Blackstone Group received these shares as part of the consideration that NRG paid for the acquisition of Texas Genco LLC. Following this repurchase, the four largest previous shareholders of Texas Genco LLC have concluded the sale of all of their NRG common stock received pursuant to the Acquisition.

On December 29, 2006, NRG repaid $400 million of the Company's term loan facility, completing the debt reduction portion of the Company's Capital Allocation Program. NRG used cash on hand to fund the repayment.

As of December 31, 2006 and February 28, 2007, there were approximately $268 million of shares to be repurchased in Phase II of the Company's Capital Allocation Program. We expect to complete Phase II during the first half of 2007.

Acquisition-Related Financing — On January 31, 2006, NRG used proceeds from the issuance of common stock and cash on hand to repay the $446 million outstanding principal balance of the Company's senior secured term loan facility and terminated the facility. On February 2, 2006, NRG used proceeds from new debt financing related to the acquisition of Texas Genco LLC to pay accrued but unpaid fees on the Company's revolving credit facility and funded letter of credit facility, and terminated those facilities. Those facilities were replaced by a new term loan, letter of credit and revolving financing facilities as of February 2, 2006.

NRG's previously outstanding 8% second priority notes of approximately $1.1 billion were extinguished by NRG on February 2, 2006, and previously outstanding Texas Genco notes of approximately $1.1 billion were purchased by NRG on February 3, 2006, with proceeds from the issuance of new unsecured high yield notes.

Second Lien Structure — NRG has granted second priority liens to certain counterparties on substantially all of the Company's assets in the United States in order to secure obligations, which are primarily long-term in nature under certain power sale agreements and related contracts. NRG uses the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under these agreements. Within the second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties. As of February 21, 2007, the net discounted exposure on the agreements and hedges that were subject to the second lien structure was approximately $182 million.

The following table summarizes the amount of MWs hedged against the Company's baseload assets and as a percentage relative to the Company's forecasted baseload capacity under the second lien structure as of February 21, 2007:

Equivalent Net Sales secured by Second Lien Structure(a)	2007	2008	2009	2010	2011	2012
In MW	3,371	3,200	3,682	3,017	3,293	591
As a percentage of total forecasted baseload capacity	57%	54%	63%	52%	57%	13%

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

Collateral — In March 2004, NRG entered into two interest rate swap agreements, one of which matured on March 31, 2006. The remaining swap agreement matures in 2011. Depending on market interest rates, NRG or the swap counterparty may be required to post collateral on a daily basis in support of this swap, to the benefit of the other party. On December 31, 2006 and February 21, 2007, NRG had posted approximately $10 million in collateral.

Preferred Stock Dividend Payments — For the year ended December 31, 2006, NRG paid approximately $9.1 million, $16.8 million and $25.0 million in dividend payments to holders of the Company's 5.75%, 4% and 3.625% Preferred Stock.

Debt Service Obligations

Project Finance Obligations — NRG is a holding company and conducts its operations primarily through subsidiaries. Consistent with NRG's strategy, it may seek, where available on commercially reasonable terms, project-level debt in connection with the assets or businesses of its affiliates, including the Company's repowering program, or the Company may develop, construct or acquire new projects in partnership with others. Project-level borrowings are substantially non-recourse to other subsidiaries, affiliates and the Company, and are generally secured by the capital stock, physical assets, contracts and cash flow of the related project subsidiary or affiliate being financed. Some of these project financings may require the Company to post collateral in the form of cash or an acceptable letter of credit.

As of December 31, 2006, NRG had approximately $4.7 billion in aggregate principal amount of unsecured high yield notes or Senior Notes and approximately $3.1 billion in principal amount outstanding under the term loan and had issued $967 million of letters of credit under the Company's $1.5 billion letter of credit facility, leaving $533 million available for future issuances. Under the Company's $1.0 billion revolving facility, as of December 31, 2006, NRG had issued $145 million in letters of credit, leaving $855 million available for borrowings, of which approximately $155 million could be used to issue additional letters of credit. As of February 21, 2007, $551 million of undrawn letters of credit remain available under the funded letter of credit facility, $141 million of undrawn letters of credit remain available under the revolving credit facility, and NRG had no borrowings on the Company's revolving credit facility.

Principal payments on debt and capital leases as of December 31, 2006 are due in the following periods:

Subsidiary/Description	2007	2008	2009	2010	2011	Thereafter	Total
				(In millions)			
Debt:							
7.375% Notes due 2017	$ —	$ —	$ —	$ —	$ —	$ 1,100	$ 1,100
7.25% Notes due 2014	—	—	—	—	—	1,200	1,200
7.375% Notes due 2016	—	—	—	—	—	2,400	2,400
Term Loan, due 2013	36	36	36	36	36	2,968	3,148
CSF Non-Recourse Obligations	—	190	143	—	—	—	333
ML Note	—	—	—	—	—	11	11
NRG Energy Center Minneapolis, due 2013 and 2017	9	10	11	11	12	50	103
NRG Peaker Finance Co LLC	11	13	15	20	21	210	290
Camas Pwr BLR LP Bank facility	1	—	—	—	—	—	1
Camas Pwr BLR LP Bonds	2	—	—	—	—	—	2
ITISA, due January 2012	3	4	4	4	4	—	19
ITISA, due December 2013	4	4	4	4	4	12	32
Subtotal Debt, Bonds and Notes	66	257	213	75	77	7,951	8,639
Capital Lease:							
Saale Energie GmbH, Schkopau	68	30	23	11	5	62	199
Other	2						2
Total Payments and Capital Leases	$136	$287	$236	$86	$82	$ 8,013	$ 8,840

Cash Flow Discussion

NRG obtains cash from operations, proceeds from the sale of certain assets and the proceeds from the issuance of notes and preferred stock. NRG uses these funds to finance operations, make interest payments, repurchase its common stock, service debt obligations, finance capital expenditures, and meet other cash and liquidity needs.

The following table reflects the changes in cash flows for the comparative years; all cash flow categories include the cash flows from both continuing operations and discontinued operations:

	Year Ended December 31,		
	2006	2005	Change
		(In millions)	
Net cash provided by operating activities	$ 408	$ 68	$ 340
Net cash provided/(used) by investing activities	(4,176)	158	(4,334)
Net cash provided/(used) by financing activities	4,053	(830)	4,883

Net Cash Provided By Operating Activities

For the year ended December 31, 2006, net cash provided by operating activities increased by $340 million compared to the year ended December 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, NRG's cash collateral deposits in support of derivative contracts decreased by $454 million for the year ended December 31, 2006, compared to an increase of $405 million for the year ended December 31, 2005, a difference of $859 million. As of December 31, 2006, NRG had cash collateral deposits of $27 million;
- Due to the redemption of NRG's previous senior notes, a premium of $126 million was paid to NRG's former debt holders;
- NRG's activity for the year ended December 31, 2006 resulted in an increase of $197 million in working capital compared to a decrease in working capital for the year ended December 31, 2005 of $7 million, a difference of $204 million;
- Due to redemption of NRG's 8% second priority notes, for the year ended December 31, 2006, NRG wrote off $61 million of deferred financing costs less debt premium of $14 million for a net write-off of $47 million, compared to a write-off of debt premiums of $8 million during the same period in 2005, a difference of $55 million; and
- A gain on the sale of emission allowances adjusted net income by $64 million to reflect the activity as investing. Due to price conditions, it was economically beneficial to sell emissions rather than operate certain plants.

Net Cash Provided/(Used) By Investing Activities

For the year ended December 31, 2006, net cash used in investing activities was approximately $4.3 billion more than for the year ended December 31, 2005. NRG's use of cash was due to the following mix of investment activities:

- During the first quarter 2006, NRG acquired Texas Genco LLC for approximately $6.2 billion (net of assumed debt), which included the issuance of stock at a value of $1.7 billion and a net cash payment of approximately $4.3 billion (net of cash on hand at Texas region of $238 million);
- NRG acquired Dynegy's 50% ownership interest in WCP for $25 million (net of cash on hand at WCP of $180 million). Prior to the purchase, NRG had an existing investment in WCP accounted for as an unconsolidated equity method investment;
- During 2006, NRG divested a number of the Company's equity investments for total proceeds of approximately $86 million; in addition, NRG received approximately $260 million in proceeds from sale of assets classified as discontinued operations; and

- NRG's capital expenditures were $115 million more for the year ended December 31, 2006 than for the year ended December 31, 2005, with the increase primarily related to capital expenditures at Texas and the Northeast regions.

Net Cash Provided/(Used) in Financing Activities

For the year ended December 31, 2006, net cash provided by financing activities increased by approximately $4.9 billion, compared to the year ended December 31, 2005. The increase was primarily due to the financing activities related to the purchase of Texas Genco LLC:

- In conjunction with the purchase of Texas Genco LLC, NRG refinanced the Company's outstanding debt as well as Texas Genco LLC's outstanding debt as NRG:
  - Repaid $446 million in outstanding principal and terminated its term loan under NRG's Amended Credit Facility;
  - Repurchased and retired approximately $1.1 billion of NRG's 8% Second Priority Notes, pursuant to a tender offer; and
  - Repurchased Texas Genco LLC outstanding notes for approximately $1.1 billion and Texas Genco LLC term loan for approximately $500 million.
- As part of raising the funds to purchase Texas Genco LLC and to refinance the NRG debt portfolio, the Company:
  - Issued 20,855,057 shares of common stock on January 31, 2006 at an offering price of $48.75 per share for total net proceeds of approximately $986 million, after deducting expenses;
  - Issued 2,000,000 shares of 5.75% Preferred Stock on January 30, 2006 at an offering price of $250 per share for total net proceeds of approximately $486 million, after deducting expenses;
  - Entered into a new senior secured credit facility providing for an aggregate amount up to $5.575 billion, consisting of a $3.575 billion Term Loan Facility, a $1.0 billion Revolving Credit Facility, and a $1.0 billion Letter of Credit Facility; and
  - Issued (i) $1.2 billion aggregate principal amount of 7.25% Senior Notes, and (ii) $2.4 billion aggregate principal amount of 7.375% Senior Notes.
- In accordance with FAS 133, as amended, payments of $296 million for the settlement of derivatives that were acquired with the acquisition of Texas Genco LLC are considered financing activities. These amounts are recorded as a reduction to revenues in the statement of operations.
- In connection with NRG's Hedge Reset transactions during the fourth quarter 2006, the Company issued approximately $1.1 billion 7.375% Senior Notes, due 2017, which were used to make cash payments to hedge counterparties of approximately $1.35 billion.
- During Phase I of the Company's Capital Allocation Program, NRG through two wholly-owned unrestricted subsidiaries issued approximately $249 million in notes and $84 million in preferred interests to partially fund the purchase of approximately $500 million of NRG's common stock for the year ended December 31, 2006.
- Phase II of the Company's Capital Allocation Program has resulted in the repurchase of an additional $232 million of the Company's common stock with cash on hand as of December 31, 2006. In addition, the company repaid $400 million in debt.

NOL's, Deferred Tax Assets and FIN 48 Implications

As of December 31, 2006, NRG had U.S. domestic net operating loss carryforwards of $72 million, which will expire in 2026.

NRG believes that it is more likely than not that a benefit will not be realized on the deferred tax assets relating to capital loss carryforwards. This assessment included consideration of positive and negative factors, including NRG's current financial position, projected future earnings and capital gains, and available tax planning strategies.

As of December 31, 2006, a valuation allowance totaling $581 million was recorded against deferred tax assets relating to U.S. domestic capital loss carryforwards and foreign net operating loss carryforwards. The valuation allowance was reduced from $836 million to $581 million due to earnings generated during 2006 by business operations as well as to the acquisition of the Texas region, which resulted in an overall reduction in the Company's valuation allowance.

The Company has completed its initial evaluation of the impact of the January 1, 2007, adoption of FIN 48 and determined that such adoption is not expected to have a material impact on the Company's financial position, results of operations and cash flows.

Discussion of Known Trends

Repowering NRG Program

NRG has announced a comprehensive portfolio redevelopment program, referred to as *Repowering NRG*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity at NRG's existing domestic sites to meet the growing demand in the Company's core markets. Through the *Repowering NRG* program, the Company anticipates retiring certain existing units and adding up to approximately 10,350 MW of new generation, with an emphasis on new baseload capacity that is supported by long-term power purchase agreements, or PPAs, and financed with limited or non-recourse project financing. NRG expects that these repowering investments will provide one or more of the following benefits: improved heat rates; lower delivered costs; expanded electricity production capability; an improved ability to dispatch economically across the merit order; increased technological and fuel diversity; and reduced environmental impacts. The Company expects that the *Repowering NRG* program will also result in indirect benefits, including the continuation of operations and retention of key personnel at its existing facilities.

A critical aspect of the *Repowering NRG* program is the extent to which the Company seeks to reduce the carbon intensity of the Company's generation fleet by developing generating facilities with zero CO_2 and low CO_2 emissions, as well as facilities that can be equipped for CO_2 separation and sequestration. As a result, the *Repowering NRG* program is important not only to NRG but also to the power industry in general. The American power industry is the primary emitter of CO_2 in the largest CO_2 emitting market on earth. As the power industry takes steps to develop the next wave of power generation infrastructure, technology and capital allocation decisions will be made which could impact GHG from power generation by either making the situation significantly worse or significantly better in terms of CO_2 intensity. Although there is no current technological solution to retro-fit existing fossil-fueled technology to capture GHG from power plant flues, there are commercially available large scale technologies for new plants that can generate power with much lower GHG emissions than traditional coal-fired generation. Given that new generation units have useful lives of up to 50 years, NRG will give full consideration to CO_2 and other emissions that contribute to GHG when making its long-term investment decisions.

As part of the *Repowering NRG* program, NRG is pursuing a five-pronged GHG emissions strategy as follows:

1. *Nuclear development* — a known, reliable source of electricity with zero emissions.

2. *IGCC development* — coal-fueled baseload generation designed to reduce the intensity of CO_2 emissions.

3. *Wind development* — renewable energy for the future with zero emissions.

4. *Public outreach* — NRG will work with government, industry and public interest groups to formulate and implement an economically and environmentally responsible GHG policy.

5. *Bridge the technology gap* — The Company has launched a number of initiatives to improve technology through R&D particularly post-combustion carbon capture, developing underground sequestration, and finding offsets that will mitigate CO_2 production.

NRG estimates that the *Repowering NRG* program, if fully implemented as currently proposed, could have a total capital cost of approximately $16 billion. While NRG believes it is extremely unlikely that the program will be fully implemented as currently proposed, the Company nonetheless expects the overall capital expenditures in connection with the program will be substantial. NRG expects to mitigate the capital cost of the program through equity partnerships and public-private partnerships, as well as through development fees for certain projects. To mitigate the investment risks, NRG anticipates entering into long-term PPAs and engineering, procurement and construction, or EPC, contracts. The Company currently expects its share of cash contributions for the projects included in the *Repowering NRG* program to range between $500 million and $2.0 billion over the next decade. However, the proposed increase in generation capacity and capital costs resulting from *Repowering NRG* could change as proposed projects are included or removed from the program due to a number of factors, including successfully obtaining required permits and long term PPAs, availability of financing on favorable terms, and achieving targeted project returns. The projects that have been identified as part of the *Repowering NRG* program are subject to change as NRG refines the program to take into account the success rate for completion of projects, changes in the targeted minimum return thresholds, and evolving market dynamics.

The following table summarizes the current projects included in the *Repowering NRG* program by fuel-type:

Fuel-type	MW
Gas	4,050
Nuclear	2,700
Coal Gasification, or IGCC	1,500
Solid Fuel	1,800
Wind	300
Total	10,350

Capital Allocation Program

As of December 31, 2006, NRG had repurchased 14,800,581 shares of Common Stock, at a cost of approximately $732 million through the Company's Capital Allocation Program, which commenced during the third quarter 2006. The program as previously announced was in two phases. Phase I was a $500 million share buyback program with Phase II, originally announced as a $250 million share repurchase. During the fourth quarter 2006, NRG increased Phase II of the share repurchase to $500 million.

On October 13, 2006, NRG completed Phase I of NRG's Capital Allocation Program with the repurchase of 10,587,700 of the Company's common stock for approximately $500 million. At maturity, should NRG's stock price exceed a compound annual growth rate of 20% beyond a volume-weighted average share price determined at the time of repurchase, referred to as the Reference Price, NRG will pay to Credit Suisse the market value of NRG's stock price over the Reference Price in either cash or stock. This difference will be recorded as an increase to the cost of the treasury shares repurchased.

On November 24, 2006, as part of Phase II of NRG's Capital Allocation Program, NRG repurchased 4,212,881 shares of NRG common stock from affiliates of the Blackstone Group at a price of $55.00 per share for a total of approximately $232 million. The Blackstone Group affiliates acquired the shares in a private placement as part of the consideration that NRG paid for the acquisition of Texas Genco LLC.

In addition, on December 29, 2006, NRG completed a $400 million debt repayment in connection with the Company's Capital Allocation Program.

As of February 28, 2007, the Company had approximately $268 million of shares to be repurchased in Phase II of the Capital Allocation Program. We expect to complete Phase II during the first half of 2007.

Resetting of Existing Hedges, or Hedge Reset

In November 2006, NRG net settled certain existing hedge agreements for the years 2006 through 2010. These hedges were entered into by Texas Genco LLC at a time when power and natural gas prices were lower than they were at the time of the Hedge Reset, and as a result, the previous hedges obligated NRG to sell power or natural gas at prices significantly below prevailing market prices. Under the amended agreements, NRG reset the pricing of these hedges to reflect prevailing market prices, and paid cash to the hedge counterparties in amounts that reflect a negotiated present value of the difference between the original prices in the hedges and the amended prices. The total amount paid to the counterparties was approximately $1.35 billion.

The Hedge Reset provided the Company's shareholders with a number of benefits. First, the Company has increased its cash flows that will be available to shareholders between 2007 and 2010 by approximately $1.5 billion. Second, it has afforded NRG the flexibility, through the Company's second lien structure, to expand the Company's hedges on baseload generation for the 2010-2012 periods, thus reducing the volatility in earnings and cash flow. Third, the Company obtained amendments of its Senior Credit Facility, which has provided the Company the ability to return more capital to shareholders, as well as greater flexibility in the Company's *Repowering NRG* program.

The following table summarizes —

- The Texas region's percentage of hedged baseload capacity and the corresponding revenues as of February 2, 2006;
- The revenues expected from those hedges following the Hedge Reset;
- The increase in cash based revenues following the Hedge Reset; and
- The expected increase in net revenues following the Hedge Reset.

	2007	**2008**	**2009**	**2010**
	(In millions unless otherwise stated)			
Texas region Net Baseload Capacity (MW)	5,340	5,340	5,340	5,340
Texas region Baseload Sales (MW)[(a)]	4,267	4,157	3,449	1,395
Percentage Baseload Capacity Sold Forward[(b)]	80%	78%	65%	26%
As of Acquisition:				
Weighted Average Forward Price ($ per MWh)[(c)(d)]	$ 39	$ 41	$ 47	$ 51
Total Forward Hedged Revenues[(c)]	1,443	1,505	1,434	621
After Hedge Reset[(d)]				
Weighted Average Forward Price ($ per MWh)[(c)(e)]	56	54	57	55
Total Forward Hedged Revenues[(c)]	2,103	1,963	$1,707	$ 723
Increase in energy revenue	660	458	273	102
Decrease in contract amortization revenue	(563)	(361)	(261)	(75)
Net impact to reported revenue	$ 97	$ 97	$ 12	$ 27

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

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

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

(d) Of the Texas region Baseload Sales, 72% of 2007, 58% of 2008, 73% of 2009 and 67% of 2010, had their price negotiated per the Hedge Reset.

(e) Includes power contract prices which are comprised of a fixed demand charge which is exclusive of a fixed energy charge. The forward price related to these contracts is the sum of both charges.

Based on the table above, due to the Hedge Reset of the Texas region's hedges that were outstanding as of February 2, 2006, revenues during the period 2007-2010 will increase by approximately $233 million.

Off-Balance Sheet Instruments and Other Contractual 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 25, *Guarantees,* to the Consolidated Financial Statements for a further discussion of these 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, which includes a conversion feature that is considered a derivative per FAS 133. Although it is considered a derivative, it is exempt from derivative accounting, as it is excluded from the scope pursuant to paragraph 11(a) of SFA 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. See Note 13, *Capital Structure,* to the Consolidated Financial Statements for a further discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments — As of December 31, 2006, NRG has not entered into any financing structure that is designed to be off-balance sheet that would create liquidity, financing, or incremental market risk or credit risk to the Company. However, NRG has 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. NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $153 million and $174 million as of December 31, 2006 and 2005, respectively. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. In the normal course of business, the Company may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and, if appropriate, bear market-based interest rates.

Synthetic Letter of Credit Facility and Revolver Facility — Under NRG's Amended Senior Credit Facility NRG entered into on November 21, 2006, the Company has a $1.5 billion synthetic Letter of Credit Facility that is unfunded by NRG, and a $1 billion senior Revolving Credit Facility. The synthetic Letter of Credit Facility is secured by a $1.5 billion cash collateral deposit, held by Deutsche Bank AG, New York Branch, as the Issuing Bank. Under the synthetic Letter of Credit Facility, NRG is allowed to issue letters of credit to support the Company's obligations under commodity hedging or power purchase arrangements. In addition, NRG can issue up to $300 million in unfunded letters of credit under the Company's Revolving Credit Facility for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the Senior Credit Facility. In addition, NRG is permitted to issue additional letters of credit up to $700 million under the Senior Credit Facility through another financial institution.

As of December 31, 2006, the Company had issued $967 million in 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 December 31, 2006, the Company had issued $145 million in revolver letters of credit, a portion of which supports non-commercial letter of credit obligations under letter of credit facilities terminated as of February 2, 2006.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs. With the acquisition of Texas Genco LLC, the Company's contractual obligations have increased significantly from the prior year. In addition, the financing related to the acquisition, as well as the sale of non-core assets during 2006, has also contributed to an increase in the Company's outstanding guarantees.

The following tables summarize NRG's contractual obligations and guarantees. For an additional discussion, see Item 15 — Note 11, *Debt and Capital Leases*, and Note 21, *Commitments and Contingencies*, to the Consolidated Financial Statements.

Contractual Cash Obligations	By Remaining Maturity at December 31, 2006 Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2005 Total
	(In millions)					
Long-term debt (including estimated interest)	$ 664	$ 1,724	$ 1,392	$ 9,650	$ 13,430	$ 3,600
Capital lease obligations (including estimated interest)	87	85	35	196	403	406
Operating leases	39	70	63	255	427	150
Fuel purchase and transportation obligations(a)	1,614	934	505	593	3,646	416
Total contractual cash obligations	$ 2,404	$ 2,813	$ 1,995	$ 10,694	$17,906	$4,572

(a) Includes only those coal transportation and gas commitments for 2007 as no other nominations were made as of December 31, 2006

Guarantees	By Remaining Maturity at December 31, 2006 Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2005 Total
	(In millions)					
Synthetic letters of credit	$ 523	$ 444	$ —	$ —	$ 967	$ —
Funded standby letters of credit	—	—	—	—	—	312
Unfunded standby letters of credit and surety bonds	97	56	—	—	153	4
Asset sales guarantee obligations	—	13	110	21	144	123
Commodity sales guarantee obligations	133	51	—	420	604	91
Other guarantees	1	—	—	28	29	91
Total guarantees	$ 754	$ 564	$ 110	$ 469	$1,897	$621

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs. See Item 15 — Note 21, *Commitments and Contingencies*, to the Consolidated Financial Statements for a discussion of commitments and contingencies that also include contractual obligations and commercial commitments that occurred during 2006.

Derivative Instruments

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

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

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

Derivative Activity Gains/(Losses)

	(In millions)
Fair value of contracts at December 31, 2005	$ (403)
Value of Flinders contracts as at December 31, 2005, reclassified as discontinued operations	73
Value of contracts acquired with NRG Texas on February 2, 2006	(472)
Value of contracts negotiated pursuant to the Hedge Reset transaction	145
Contracts realized or otherwise settled during the period	165
Changes in fair value	846
Fair value of contracts at December 31, 2006	$ 354

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts as of December 31, 2006				
Sources of Fair Value Gains/(Losses)	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	$ 80	$ —	$ —	$ —	$ 80
Prices provided by other external sources	183	72	26	(19)	262
Prices provided by models and other valuation methods	3	9	—	—	12
Total	$ 266	$ 81	$ 26	$ (19)	$ 354

Critical Accounting Policies and Estimates

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

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

NRG's significant accounting policies are summarized in Item 15 — Note 2, *Summary of Significant Accounting Policies*, to the Consolidated Financial Statements. The Company identifies its most critical accounting policies as those that are the most pervasive and important to the portrayal of the Company's financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain.

Accounting Policy	
Derivative Financial Instruments	• Assumptions used in valuation techniques • Assumptions used in forecasting generation • Market maturity and economic conditions • Contract interpretation • Market conditions in the energy industry, especially the effects of price volatility on contractual commitments • Regulatory and political environments and requirements
Income Taxes and Valuation Allowance for Deferred Tax Assets	• Ability of tax authority decisions to withstand legal challenges or appeals • Anticipated future decisions of tax authorities • Application of tax statutes and regulations to transactions • Ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods
Impairment of Long Lived Assets	• Recoverability of investment through future operations • Regulatory and political environments and requirements • Estimated useful lives of assets • Environmental obligations and operational limitations • Estimates of future cash flows • Estimates of fair value (fresh start) • Judgment about triggering events
Goodwill and Other Intangible Assets	• Estimated useful lives for finite-lived intangible assets • Judgment about impairment triggering events • Estimates of reporting unit's fair value • Fair value estimate of certain power sales and fuel contracts using forward pricing curves as of the closing date over the life of each contract
Contingencies	• Estimated financial impact of event(s) • Judgment about likelihood of event(s) occurring

Derivative Financial Instruments

The Company follows the guidance of SFAS 133, as amended, to account for derivative financial instruments. SFAS 133 requires the Company to mark-to-market all derivative instruments on the balance sheet, and recognize changes in the fair value of non-hedge derivative instruments immediately in earnings. In certain cases, NRG may apply hedge accounting to the Company's derivative instruments. The criteria used to determine if hedge accounting treatment is appropriate are: (i) the designation of the hedge to an underlying exposure, (ii) whether the overall risk is being reduced; and (iii) if there is a correlation between the fair value of the derivative instrument and the underlying hedged item. Changes in the fair value of derivatives instruments accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged item, or deferred and recorded as a component of OCI, and subsequently recognized in earnings when the hedged transactions occur.

For purposes of measuring the fair value of derivative instruments, NRG uses quoted exchange prices and broker quotes. When external prices are not available, NRG uses internal models to determine the fair value. These internal models include assumptions of the future prices of energy based on the specific market in which the energy is being sold, using externally available forward market pricing curves for all periods possible under the pricing model. In order to qualify derivatives instruments for hedged transactions, NRG estimates the forecasted generation occurring within a specified time period. Judgments related to the probability of forecasted generation occurring are based on available baseload capacity, internal forecasts of sales and generation, and historical physical delivery on similar contracts. The probability that hedged forecasted generation will occur by the end of a specified time period could change the results of operations by requiring amounts currently classified in OCI to be reclassified into earnings, creating increased variability in our earnings. These estimations are considered to be critical accounting estimates.

Certain derivative financial instruments that meet the criteria for derivative accounting treatment also qualify for a scope exception to derivative accounting, as they are considered Normal Purchase and Normal Sales, or NPNS. The availability of this exception is based upon the assumption that NRG has the ability and it is probable to deliver or take delivery of the underlying item. These assumptions are based on available baseload capacity, internal forecasts of sales and generation, and historical physical delivery on contracts. Derivatives that are considered to be NPNS are exempt from derivative accounting treatment, and are accounted for under accrual accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception due to changes in estimates, the related contract would be recorded on the balance sheet at fair value combined with the immediate recognition through earnings.

Income Taxes and Valuation Allowance for Deferred Tax Assets

As of December 31, 2006, NRG had a valuation allowance of approximately $581 million related to the Company's U.S. domestic capital loss carryforwards of approximately $506 million and foreign net operating loss carryforwards of approximately $75 million. In assessing the recoverability of NRG's deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected capital gains and available tax planning strategies.

As of December 31, 2006, NRG had approximately $72 million of U.S. federal and state net operating loss, or NOL, carryforwards for financial reporting purposes. The utilization of the Company's NOLs depends on several factors, such as NRG's ability to utilize tax benefits through carryforwards to future periods, the application of tax statutes and regulations to transactions.

NRG continues to be under audit for multiple years by taxing authorities in other jurisdictions. Considerable judgment is required to determine the tax treatment of a particular item that involves interpretations of complex tax laws. A tax liability has been recorded for certain tax filing positions where the Company cannot sustain the tax return position at a should level of certainty. Such liabilities are based on management's judgment, which considers the best estimate of the amount and probable outcome of the tax position, and it can take several years between the time when a liability is recorded and when the related filing position is resolved with the taxing authority. Management periodically reviews these matters and adjusts the liabilities recorded on the financial statements as appropriate.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, or SFAS 144, NRG evaluates property, plant and equipment and intangible assets for impairment whenever indicators of impairment exist. Examples of such indicators or events are:

- Significant decrease in the market price of a long-lived asset;
- Significant adverse change in the manner an asset is being used or its physical condition;

- Adverse business climate;
- Accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,
- Current-period loss combined with a history of losses or the projection of future losses; and
- Change in the Company's intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset, through considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available to the Company. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. NRG uses its best estimates in making these evaluations and considers various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in the Company's estimates, and the impact of such variations could be material.

For assets to be held and used, if the Company determines that the undiscounted cash flows from the asset are less than the carrying amount of the asset, NRG must estimate fair value to determine the amount of any impairment loss. Assets held-for-sale are reported at the lower of the carrying amount or fair value less the cost to sell. The estimation of fair value under SFAS 144, whether in conjunction with an asset to be held and used or with an asset held-for-sale, and the evaluation of asset impairment are, by their nature, subjective. NRG considers quoted market prices in active markets to the extent they are available. In the absence of such information, the Company may consider prices of similar assets, consult with brokers, or employ other valuation techniques. NRG will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as previously discussed with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in the Company's estimates, and the impact of such variations could be material.

NRG is also required to evaluate its equity-method and cost-method investments to determine whether or not they are impaired. Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*, or APB18, provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under APB 18 is whether the value is considered an "other than a temporary" decline in value. The evaluation and measurement of impairments under APB 18 involves the same uncertainties as described for long-lived assets that the Company owns directly and accounts for in accordance with SFAS 144. Similarly, the estimates that NRG makes with respect to its equity and cost-method investments are subjective, and the impact of variations in these estimates could be material. Additionally, if the projects in which the Company hold these investments recognize an impairment under the provisions of SFAS 144, NRG would record its proportionate share of that impairment loss and would evaluate its investment for an other than temporary decline in value under APB 18.

For the year ended December 31, 2006, there was no reduction in income from continuing operation due to investment impairment. For the years ended December 31, 2005 and 2004, income from continuing operations was reduced by $6 million and $45 million, respectively, due to investment impairments.

Goodwill and Other Intangible Assets

As part of the acquisition of Texas Genco LLC, NRG recorded intangible assets and goodwill. The Company applied SFAS No. 141, *Business Combinations,* or SFAS 141, and SFAS No. 142, *Goodwill and Other Intangible Assets*, or SFAS 142, to account for these intangibles. Under these standards, the Company amortizes all finite-lived intangible assets over their respective estimated weighted-average useful lives, while goodwill has an indefinite life and is not amortized. However, goodwill and all intangible assets not subject to amortization will be tested for impairment whenever an event occurs that indicates that an impairment may have occurred, or at a minimum, on an annual basis. Where necessary, the Company's goodwill and/or intangible asset will be impaired at that time.

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

Contingencies

NRG records a loss contingency when management determines it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Gain contingencies are not recorded until management determines it is certain that the future event will become or does become a reality. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events, and estimates of the financial impacts of such events. NRG describes in detail its contingencies in Item 15 — Note 21, *Commitments and Contingencies,* to the Consolidated Financial Statements.

Recent Accounting Developments

See Item 15 — Note 2, *Summary of Significant Accounting Policy,* to the Consolidated Financial Statements for a discussion of recent accounting developments.

Item 7A — *Quantitative and Qualitative Disclosures about Market Risk*

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

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

Commodity Price Risk

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

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

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

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

NRG measures the sensitivity of the Company's portfolio to potential changes in market prices using Value at Risk, or VAR. VAR is a statistical model that attempts to predict risk of loss based on market price volatility. Currently, the company estimates VAR using a Monte Carlo simulation based methodology. Prior to November 2006, NRG used a Variance/Covariance based VAR methodology. NRG's total portfolio includes mark-to-market and non mark-to-market energy assets and liabilities.

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

As of December 31, 2006, the VAR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VAR model was $18 million.

The following table summarizes average, maximum and minimum VAR for NRG for the year ended December 31, 2006:

VAR	In millions
As of December 31, 2006	$ 18
Average(a)	39
Maximum(a)	67
Minimum(a)	17
As of December 31, 2005	$ 37
Average	28
Maximum	46
Minimum	16

(a) Includes Texas region portfolio beginning the third quarter 2006.

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

In order to provide additional information for comparative purposes to NRG's peers, the Company also utilizes VAR to estimate of the potential loss of financial derivative instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes.

The VAR for the financial derivative instruments calculated using the diversified VAR model as of December 31, 2006 for the entire term of these instruments entered into for both asset management and trading was approximately $32 million.

Interest Rate Risk

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

In January 2006, the Company entered into a series of new interest rate swaps. These interest rate swaps became effective on February 15, 2006, and are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, NRG pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the equivalent of a floating interest payment based on a 3-month LIBOR rate calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of December 31, 2006 was $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

As of December 31, 2006, the Company had various interest rate swap agreements, including those listed above, with notional amounts totaling approximately $2.8 billion. If the swaps had been discontinued on December 31, 2006, the Company would have owed the counter-parties approximately $10 million. Based on the investment grade rating of the counter-parties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of December 31, 2006, a 100 basis point change in interest rates would result in a $15.1 million change in interest expense on a rolling twelve month basis.

As of December 31, 2006, the fair value and the carrying amount of the Company's long-term debt was $8.8 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company's long-term debt by $549 million.

Liquidity Risk

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

Based on a sensitivity analysis, a $1 per MWh increase or decrease in electricity prices across the term of the marginable contracts would cause a change in margin collateral outstanding of approximately $40 million as of December 31, 2006. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2006.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages the credit risk of NRG and its subsidiaries through credit policies that include (i) an established credit approval process, (ii) a daily monitoring of counter-party credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements, and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company has credit protection within various agreements to call on additional collateral support if and when necessary. As of December 31, 2006, NRG held collateral support of approximately $681 million from counterparties.

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

The following table highlights the credit quality and their balance sheet settlement exposures related to these activities as of December 31, 2006:

Credit Exposure	Exposure Before Collateral	Collateral	Net Exposure
	(In millions, except ratios)		
Investment grade	$ 1,812	$ 349	$ 1,463
Non-investment grade	84	73	11
Not rated	146	3	143
Total	$ 2,042	$ 425	$ 1,617
Investment grade	89%	82%	90%
Non-investment grade	4%	17%	1%
Not rated	7%	1%	9%

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

NRG's exposure to significant counterparties greater than 10% of the net exposure of approximately $1.6 billion was approximately $1.2 billion as of December 31, 2006. NRG does not anticipate any material adverse effect on the Company's financial position or results of operations as a result of nonperformance by any of NRG's counterparties.

Currency Exchange Risk

NRG is exposed to foreign currency risks associated with foreign-denominated distributions from the Company's international investments. In the normal course of business, NRG may receive distributions denominated in the Euro, Australian Dollar and the Brazilian Real. Occasionally, NRG engages in a strategy of hedging foreign denominated cash flows for these related currency inflows, and to the extent required, fixes the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swaps agreements with highly credit worthy financial institutions.

As of December 31, 2006, a 10% devaluation in the currency of all of the Company's exposure currencies would result in an immaterial impact to NRG's consolidated statements of operations. However, NRG's consolidated financial position would also have been negatively affected by approximately $60 million, due to currency translation adjustments recorded in OCI.

Item 8 — *Financial Statements and Supplementary Data*

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K.

Item 9 — *Changes in and Disagreements with Accountants on Accounting and Financial Disclosures*

None.

Item 9A — *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of NRG's management, including its principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of its disclosure controls and procedures, as such term is defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, the Company's principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this annual report on Form 10-K.

Changes in Internal Control Over Financial Reporting

With the completion and associated integration of the acquisition of Texas Genco LLC and WCP, there have been no changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the year ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

Inherent Limitations Over Internal Controls

NRG's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. The Company's internal control over financial reporting includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

2. Provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

3. Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Item 9B — *Other Information*

None.

PART III

Item 10 — *Directors and Executive Officers of the Registrant*

NRG Energy, Inc. has adopted a code of ethics entitled “NRG Code of Conduct” that applies to directors, officers and employees, including the chief executive officer and senior financial officers of NRG Energy, Inc. It may be accessed through the Corporate Governance section of NRG Energy Inc.’s website at *http://www.nrgenergy.com/investor/corpgov/.htm.* NRG Energy, Inc. also elects to disclose the information required by Form 8-K, Item 5.05, “Amendments to the registrant’s code of ethics, or waiver of a provision of the code of ethics,” through the Company’s website, and such information will remain available on this website for at least a 12-month period. A copy of the “NRG Energy, Inc. Code of Conduct” is available in print to any shareholder who requests it.

Other information required by this Item will be incorporated by reference to the similarly named section of NRG’s definitive Proxy Statement for its 2007 Annual Meeting of Stockholders to be held April 25, 2007.

Item 11 — *Executive Compensation*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG’s definitive Proxy Statement for its 2007 Annual Meeting of Stockholders to be held April 25, 2007.

Item 12 — *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG’s definitive Proxy Statement for its 2007 Annual Meeting of Stockholders to be held April 25, 2007.

Item 13 — *Certain Relationships and Related Transactions*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG’s definitive Proxy Statement for its 2007 Annual Meeting of Stockholders to be held April 25, 2007.

Item 14 — *Principal Accountant Fees and Services*

Other information required by this Item will be incorporated by reference to the similarly named section of NRG’s definitive Proxy Statement for its 2007 Annual Meeting of Stockholders to be held April 25, 2007.

PART IV

Item 15 — *Exhibits and Financial Statement Schedules*

(a)(1) Financial Statements

The following consolidated financial statements of NRG Energy, Inc. and related notes thereto, together with the reports thereon of KPMG LLP are included herein:

Consolidated Statement of Operations — Years ended December 31, 2006, 2005 and 2004

Consolidated Balance Sheet — December 31, 2006 and December 31, 2005

Consolidated Statement of Cash Flows — Years ended December 31, 2006, 2005 and 2004

Consolidated Statement of Stockholders' Equity and Comprehensive Income/(Loss) — Years ended December 31, 2006, 2005 and 2004

Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedule

The following Consolidated Financial Statement Schedule of NRG Energy, Inc. is filed as part of Item 15(d) of this report and should be read in conjunction with the Consolidated Financial Statements.

Schedule II — Valuation and Qualifying Accounts

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.

(a)(3) *Exhibits:* See Exhibit Index submitted as a separate section of this report.

(b) Exhibits

See Exhibit Index submitted as a separate section of this report.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NRG Energy Inc.'s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in Internal Control — Integrated Framework, the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2006.

NRG Energy, Inc.'s management assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by KPMG LLP, the Company's independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that NRG Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). NRG Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that NRG Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, NRG Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of NRG Energy, Inc. as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and comprehensive income/(loss), and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and comprehensive income/(loss), and cash flows for each of the years in the three-year period ended December 31, 2006. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule "Schedule II. Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Emerging Issues Task Force No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry," and Statement of Financial Accounting Standards (SFAS) No. 123(R), "Share Based Payments," and related interpretations on January 1, 2006. As discussed in Note 12 to the consolidated financial statements, the Company also adopted the disclosure requirements of SFAS No. 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106 and 132(R)" effective December 31, 2006.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc.'s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2007

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2006	2005	2004
	(In millions except per share amounts)		
Operating Revenues			
Total operating revenues	$5,623	$ 2,430	$ 2,104
Operating Costs and Expenses			
Cost of operations	3,276	1,838	1,290
Depreciation and amortization	593	162	179
General, administrative and development	316	181	197
Corporate relocation charges	—	6	16
Reorganization items	—	—	(13)
Impairment charges	—	6	45
Total operating costs and expenses	4,185	2,193	1,714
Operating Income	1,438	237	390
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	60	104	160
Write downs and gains/(losses) on sales of equity method investments	8	(31)	(16)
Other income, net	160	58	22
Refinancing expenses	(187)	(65)	(72)
Interest expense	(599)	(184)	(255)
Total other expenses	(558)	(118)	(161)
Income From Continuing Operations Before Income Taxes	880	119	229
Income Tax Expense	325	47	74
Income From Continuing Operations	555	72	155
Income on Discontinued Operations, net of Income Taxes	66	12	31
Net Income	621	84	186
Preference stock dividends	50	20	—
Income Available for Common Stockholders	$ 571	$ 64	$ 186
Weighted Average Number of Common Shares Outstanding — Basic	129	85	100
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 3.90	$ 0.61	$ 1.55
Income From Discontinued Operations per Weighted Average Common Share — Basic	0.51	0.15	0.31
Net Income per Weighted Average Common Share — Basic	4.41	0.76	1.86
Weighted Average Number of Common Shares Outstanding — Diluted	150	85	100
Income From Continuing Operations per Weighted Average Common Share — Diluted	3.63	0.61	1.54
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.44	0.14	0.31
Net Income per Weighted Average Common Share — Diluted	$ 4.07	$ 0.75	$ 1.85

See notes to Consolidated Financial Statements

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2006	As of December 31, 2005
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 795	$ 493
Restricted cash	44	49
Accounts receivable — trade, less allowance for doubtful accounts of $1 and $2	372	245
Accounts receivable — affiliate	—	4
Current portion of capital lease	27	24
Taxes receivable	63	43
Inventory	421	240
Derivative instruments valuation	1,230	387
Collateral on deposits in support of energy risk management activities	27	438
Prepayments and other current assets	104	120
Current assets — held-for-sale	—	43
Current assets — discontinued operations	—	110
Total current assets	3,083	2,196
Property, Plant and Equipment		
In service	12,496	2,904
Under construction	88	37
Total property, plant and equipment	12,584	2,941
Less accumulated depreciation	(984)	(332)
Net property, plant and equipment	11,600	2,609
Other Assets		
Equity investments in affiliates	344	602
Note receivable, less current portion — affiliates	114	103
Capital lease, less current portion	365	354
Goodwill	1,789	—
Intangible assets, net of accumulated amortization of $259 and $79	981	257
Nuclear decommissioning trust fund	352	—
Derivative instruments valuation	439	18
Funded letter of credit	—	350
Deferred income taxes	27	26
Other non-current assets	262	124
Intangible assets held-for-sale	79	—
Non-current assets — discontinued operations	—	827
Total other assets	4,752	2,661
Total Assets	$ 19,435	$ 7,466

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

	As of December 31, 2006	As of December 31, 2005
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 130	$ 95
Accounts payable — trade	330	241
Accounts payable — affiliates	2	—
Derivative instruments valuation	964	679
Deferred income taxes	164	—
Accrued expenses	262	76
Other current liabilities	180	96
Current liabilities — discontinued operations	—	170
Total current liabilities	2,032	1,357
Other Liabilities		
Long-term debt and capital leases	8,647	2,410
Nuclear decommissioning reserve	289	—
Nuclear decommissioning trust liability	324	—
Postretirement and other benefit obligations	301	103
Deferred income taxes	554	128
Derivative instruments valuation	351	56
Out-of-market contracts	897	298
Other non-current liabilities	134	67
Non-current liabilities — discontinued operations	—	569
Total non-current liabilities	11,497	3,631
Total Liabilities	13,529	4,988
Minority Interest	1	1
3.625% convertible perpetual preferred stock, $0.01 par value; 250,000 shares issued and outstanding (at liquidation value, net of issuance costs)	247	246
Commitments and Contingencies		
Stockholders' Equity		
4% convertible perpetual preferred stock; $0.01 par value; 420,000 shares issued and outstanding at December 31, 2006 and 2005 (at liquidation value of $420, net of issuance costs)	406	406
5.75% convertible perpetual preferred stock; $0.01 par value, 2,000,000 shares issued and outstanding at December 31, 2006 (at liquidation value of $500, net of issuance costs)	486	—
Common Stock; $.01 par value; 500,000,000 shares authorized; 137,124,132 and 100,048,676 shares issued and 122,323,551 and 80,701,888 outstanding	1	1
Additional paid-in capital	4,476	2,431
Retained earnings	739	261
Less treasury stock, at cost — 14,800,581 and 19,346,788 shares	(732)	(663)
Accumulated other comprehensive income/(loss)	282	(205)
Total Stockholders' Equity	5,658	2,231
Total Liabilities and Stockholders' Equity	$ 19,435	$ 7,466

See notes to Consolidated Financial Statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME/(LOSS)

	Serial Preferred Stock	Serial Preferred Shares	Common Stock	Common Shares	Additional Paid-In Capital	Retained Earnings	Treasury Equity/	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity
					(In millions)				
Balances at December 31, 2003	$ —	—	$ 1	100	$ 2,403	$ 11	$ —	$ 22	$ 2,437
Net income						186			186
Foreign currency translation adjustments								46	46
Unrealized gain on derivatives								8	8
Comprehensive income for 2004									240
Equity-based compensation					14				14
Issuance of preferred stock	406	0.4							406
Purchase of treasury stock				(13)			(405)		(405)
Balances at December 31, 2004	$406	0.4	$ 1	87	$ 2,417	$ 197	$ (405)	$ 76	$ 2,692
Net income						84			84
Foreign currency translation adjustments								(72)	(72)
Unrealized loss on derivatives								(203)	(203)
Minimum pension liability, net of $3 tax								(6)	(6)
Comprehensive loss for 2005									(197)
Equity-based compensation					14				14
Preferred stock dividends						(20)			(20)
Purchase of treasury stock				(6)			(258)		(258)
Balances at December 31, 2005	$406	0.4	$ 1	81	$ 2,431	$ 261	$ (663)	$ (205)	$ 2,231
Net income						621			621
Foreign currency translation adjustments								60	60
Unrealized gain on derivatives, net of $135 tax								405	405
Minimum Pension Liability, net of $3 tax								7	7
Comprehensive income for 2006									1,093
Impact upon adoption of SFAS 158, net of $10 tax								15	15
Reduction to Tax Valuation Allowance					17				17
Impact upon adoption of EITF 04-6						(93)			(93)
Equity-based compensation					14				14
Issuance of common stock to the public				21	986				986
Issuance of preferred stock	486	2.0							486
Issuance of common and treasury stock to the shareholders of Texas Genco LLC				35	1,028		663		1,691
Preferred stock dividends						(50)			(50)
Purchase of treasury stock				(15)			(732)		(732)
Balances at December 31, 2006	$892	2.4	$ 1	122	$ 4,476	$ 739	$ (732)	$ 282	$ 5,658

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Cash Flows from Operating Activities			
Net income	$ 621	$ 84	$ 186
Adjustments to reconcile net income to net cash provided by operating activities			
Distributions in excess/(less than) equity in earnings of unconsolidated affiliates	(33)	(8)	(1)
Depreciation and amortization of nuclear fuel	654	195	215
Amortization and write-off of deferred financing costs and debt discount/premiums	79	14	70
Amortization of intangibles and out-of-market contracts	(490)	17	52
Amortization of equity-based compensation	14	12	14
Write down and gains on sale of equity method investments	(8)	31	16
Loss on sale and disposal of equipment	10	4	1
Impairment charges	—	6	45
Changes in derivatives	(149)	143	(74)
Changes in deferred income taxes	327	2	57
Gain on legal settlement	(67)	(14)	—
Gain on sale of discontinued operations	(76)	(6)	(23)
Gain on sale of emission allowances	(64)	—	—
Change in nuclear decommissioning trust liability	12	—	—
Changes in collateral deposits supporting energy risk management activities	454	(405)	(7)
Settlement of out-of-market power contracts	(1,073)	—	—
Cash provided by changes in other working capital, net of acquisition and disposition effects			
Accounts receivable, net	87	(8)	(52)
Xcel Energy settlement receivable	—	—	640
Inventory	(50)	(14)	(56)
Prepayments and other current assets	43	(35)	126
Creditor pool obligation payments	—	—	(540)
Accounts payable	(73)	57	50
Accrued expenses and other current liabilities	133	(16)	(127)
Other assets and liabilities	57	9	53
Net Cash Provided by Operating Activities	408	68	645
Cash Flows from Investing Activities			
Acquisition of Texas Genco LLC, net of cash acquired	(4,302)	(5)	—
Acquisition of WCP and Padoma, net of cash acquired	(31)	—	—
Capital expenditures	(221)	(106)	(119)
Decrease/(increase) in restricted cash, net	6	45	(27)
Decrease in notes receivable	27	107	25
Purchases of emission allowances	(135)	—	—
Proceeds from sale of emission allowances	146	—	—
Investments in nuclear decommissioning trust fund securities	(227)	—	—
Proceeds from sales of nuclear decommissioning trust fund securities	214	—	—
Proceeds from sale of investments and equipment	86	79	55
Proceeds from sale of discontinued operations	260	36	253
Return of capital from equity method investments/(Investments in projects)	1	2	(3)
Net Cash Provided/(Used) by Investing Activities	(4,176)	158	184
Cash Flows from Financing Activities			
Payment of dividends to preferred stockholders	(50)	(20)	—
Payment of financing element of acquired derivatives	(296)	—	—
Payment for treasury stock	(732)	(250)	(405)
Payment of minority interest obligations	—	(4)	—
Funded letter of credit	350	—	(100)
Proceeds from issuance of common stock, net of issuance costs	986	—	—
Proceeds from issuance of preferred shares, net of issuance costs	486	246	406
Proceeds from issuance of long-term debt	8,619	249	1,333
Payment of deferred debt issuance costs	(199)	(46)	(26)
Payments for short and long-term debt	(5,111)	(1,005)	(1,492)
Net Cash Provided/(Used) by Financing Activities	4,053	(830)	(284)
Change in Cash from Discontinued Operations	13	30	(14)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	4	(2)	3
Net Increase in Cash and Cash Equivalents	302	(576)	534
Cash and Cash Equivalents at Beginning of Period	493	1,069	535
Cash and Cash Equivalents at End of Period	$ 795	$ 493	$ 1,069

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Nature of Business

General

NRG Energy, Inc., NRG, or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is primarily engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and internationally.

As of December 31, 2006, NRG had a total portfolio of 223 active operating generation units at 51 power generation plants, with an aggregate generation capacity of approximately 24,175 MW. Within the United States, the company has a power generation portfolio of approximately 22,940 MW of generation capacity in 207 active generating units at 45 plants, primarily located in the Texas or ERCOT region (approximately 10,760 MW), the Northeast (approximately 7,240 MW), South Central (approximately 2,850 MW), and West (approximately 1,965 MW) regions of the United States, with approximately 125 MW from the Company's thermal assets.

NRG was incorporated as a Delaware corporation on May 29, 1992. NRG's common stock is listed on the New York Stock Exchange under the symbol "NRG". The Company's headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. NRG's telephone number is (609) 524-4500. The address of the Company's website is www.nrgenergy.com. NRG's recent annual reports, quarterly reports, current reports, and other periodic filings are available free of charge through the Company's website.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include NRG's accounts and operations and those of its subsidiaries in which the Company has a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. The usual condition for a controlling financial interest is ownership of a majority of the voting interests of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

As such, NRG applies the guidance of FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities,* or FIN 46R, to consolidate variable interest entities, or VIEs, for which the Company is the primary beneficiary. FIN 46R requires a variable interest holder to consolidate a VIE if that party will absorb a majority of the expected losses of the VIE, receive the majority of the expected residual returns of the VIE, or both. This party is considered the primary beneficiary. Conversely, NRG will not consolidate a VIE in which it has a majority ownership interest when the Company is not considered the primary beneficiary. In determining the primary beneficiary, NRG thoroughly evaluates the VIEs design, capital structure, and relationships among variable interest holders. If a primary beneficiary cannot be determined by a qualitative analysis, a quantitative analysis of allocating the expected cash flows among the variable interest holders is used in the determination.

Accounting policies for all of NRG's operations are in accordance with accounting principles generally accepted in the United States of America. As discussed in Note 14, *Investments Accounted for by the Equity Method*, NRG also has investments in partnerships, joint ventures and projects.

Fresh Start Reporting

In accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code,* or SOP 90-7, certain companies qualify for fresh start reporting in connection with their emergence from bankruptcy. Fresh start reporting is appropriate on the emergence from chapter 11 bankruptcy if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post-petition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. NRG met these requirements and adopted Fresh Start reporting upon the Company's emergence from bankruptcy on December 5, 2003.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments, primarily commercial paper and money market accounts, with an original maturity of three months or less at the time of purchase.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within the Company's projects that are restricted in their use. These funds are used to pay for current operating expenses and current debt service payments, per the restrictions of the debt agreements.

Inventory

Inventory is valued at the lower of weighted average cost or market and consists principally of fuel oil, coal and raw materials used to generate steam. Spare parts inventory are valued at a weighted average cost, since the Company expects to recover these costs in the ordinary course of business. Sales of inventory are classified as an operating activity in the consolidated statements of cash flows.

Property, Plant and Equipment

Property, plant and equipment are stated at cost however impairment adjustments are recorded whenever events or changes in circumstances indicate that their carrying values may not be recoverable. NRG also classifies nuclear fuel related to the Company's 44% ownership interest in STP as part of the Company's property, plant, and equipment. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation other than nuclear fuel is computed using the straight-line method, while nuclear fuel is amortized based on units of production over the estimated useful lives. Certain assets and their related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in other income/(expense) in the consolidated statements of operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* or SFAS 144. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value with the difference recorded in operating costs and expenses in the statements of operations. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

The following table summarizes the Company's asset impairment charges for the years ended December 31, 2005, and 2004. NRG did not recognize any impairment charges for the year ended December 31, 2006.

	Year Ended December 31, 2005	Year Ended December 31, 2004	Fair Value Basis
	(In millions)		
Turbines	$ 6	$ 15	Sales price
Kendall asset group	—	27	Realized loss
Other	—	3	Estimated market price
Total impairment charges	$ 6	$ 45	

Investments accounted for by the equity method are reviewed for impairment in accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, or APB 18, which requires that a loss in value of an investment that is other than a temporary decline should be recognized. The Company identifies and measures losses in the value of equity method investments based upon a comparison of fair value to carrying value.

Discontinued Operations

Long-lived assets are classified as discontinued operations when all of the required criteria specified in SFAS 144 are met. These criteria include, among others, existence of a qualified plan to dispose of an asset, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

Project Development Costs and Capitalized Interest

Development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, Board of Director approval pursuant to a formal project plan that subjects the Company to significant future obligations that can only be discharged by the use of a Company asset. When a project is available for operations, previously capitalized project costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Interest incurred on funds borrowed to finance capital projects is capitalized if material. Capitalization of interest is discontinued when the asset under construction is ready for its intended use or when a project is terminated or construction ceases.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis which approximates the effective interest method over the term of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by NRG. The Company recognizes specifically identifiable intangible assets including emission allowances, power and fuel contracts when specific rights and contracts are acquired. In addition, NRG also established values for emission allowances and power contracts upon adoption of Fresh Start reporting. These intangible assets are amortized on either contracted volumes, straight line or units of production basis.

Intangible assets determined to have indefinite lives are not amortized, but rather are tested for impairment at least annually or more frequently if events or changes in circumstances indicate that such acquired intangible assets have been determined to have finite lives and should now be amortized over their useful lives. NRG had no intangible assets with indefinite lives recorded as of December 31, 2006.

Goodwill

In accordance with SFAS 142, *Goodwill and Other Intangible Assets*, the Company recognizes goodwill for the excess cost of an acquired entity over the net value assigned to assets acquired and liabilities assumed.

NRG performs goodwill impairment tests annually typically during the fourth quarter and when events or changes in circumstances indicate that the carrying value may not be recoverable. Goodwill impairment is determined using a two step process:

Step one — Identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value exceeds book value, goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, proceed to step two.

Step two — Compare the implied fair value of the reporting unit's goodwill to the book value of the reporting unit goodwill. If the book value of goodwill exceeds fair value, an impairment charge is recognized for the sum of such excess.

Income Taxes

NRG accounts for income taxes using the liability method in accordance with SFAS No. 109, *Accounting for Income Taxes*, or FAS 109, which requires that the Company use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

NRG has two categories of income tax expense or benefit — current and deferred, as follows:

- Current income tax expense or benefit consists solely of regular tax less applicable tax credits, and
- Deferred income tax expense or benefit is the change in the net deferred income tax asset or liability, excluding amounts charged or credited to accumulated other comprehensive income.

NRG reports some of the Company's revenues and expenses differently for financial statement purposes than for income tax return purposes resulting in temporary and permanent differences between the Company's financial statements and income tax returns. The tax effects of such temporary differences are recorded as either deferred income tax assets or deferred income tax liabilities in the Company's consolidated balance sheets. NRG measures the Company's deferred income tax assets and deferred income tax liabilities using income tax rates that are currently in effect. A valuation allowance is recorded to reduce the Company's net deferred tax liabilities to an amount that is more likely than not to be realized.

Revenue Recognition

NRG is primarily a power generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which the Company's ownership interest is 50% or less, which are accounted for under the equity method of accounting. NRG also produces thermal energy for sale to customers, principally through steam and chilled water facilities.

Energy — Both physical and financial transactions are entered into to optimize the financial performance of NRG's generating facilities. Electric energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in the Company's consolidated statements of operations. Financial transactions, or the buying and selling of energy for trading purposes, are recorded net within operating revenues in the consolidated statements of operations in accordance with EITF 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

Capacity — Capacity revenues are recognized when contractually earned, and consists of revenues received from a third party at either the market or a negotiated contract price for making installed generation capacity available in order to satisfy system integrity and reliability requirements.

Sale of Emission Allowances — NRG records the Company's bank of emission allowances as part of the Company's intangible assets. From time to time, management may authorize the transfer from the Company's emission bank to intangible assets held-for-sale as part of the Company's asset optimization strategy. NRG records the sale of emission allowances on a net basis within other income in the Company's consolidated statements of operations.

Contract Amortization — Liabilities recognized from power sales agreements assumed at Fresh Start and through acquisitions related to the sale of electric capacity and energy in future periods for which the fair value has been determined to be significantly less than market is amortized as an increase to revenue over the term of each underlying contract based on actual generation and/or contracted volumes.

Derivative Financial Instruments

NRG accounts for derivative financial instruments under SFAS 133, as amended. SFAS 133 requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a Normal Purchase or Normal Sale, or NPNS, exception. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either:

- Recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments; or
- Deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings for forecasted transactions.

NRG's primary derivative instruments are power sales contracts, fuels purchase contracts, other energy related commodities, and interest rate instruments used to mitigate variability in earnings due to fluctuations in market prices and interest rates. On an ongoing basis, NRG assesses the effectiveness of all derivatives that are designated as hedges for accounting purposes in order to determine that each derivative continues to be highly effective in offsetting changes in fair values or cash flows of hedged items. Internal analyses that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such an energy contract designated as a hedge. If it is determined that the derivative instrument is not highly effective as a hedge, hedge accounting will be discontinued prospectively. Hedge accounting will also be discontinued on contracts related to commodity price risk previously accounted for as cash flow hedges when it is probable that delivery will not be made against these contracts. If the derivative instrument is terminated, the effective portion of this derivative in OCI will be frozen until the underlying hedged item is delivered.

Revenues and expenses on contracts that qualify for the NPNS exception are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments under SFAS 133, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception, the fair value of the related contract is recorded on the balance sheet and immediately recognized through earnings.

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

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG's foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are accumulated and reported as a separate component of stockholders' equity and are not included in the determination of the Company's statements of operations. Foreign currency transaction gains or losses are reported within other income/(expense) in the Company's statements of operations. For the years ended December 31, 2006, 2005 and 2004, amounts recognized as foreign currency transaction gains/losses were immaterial.

Concentrations of Credit Risk

Financial instruments, which potentially subject NRG to concentrations of credit risk, consist primarily of cash, trust funds, accounts receivable, notes receivable, and investments in debt securities. Cash accounts and trust funds are generally held in federally insured banks. Accounts receivable, notes receivable, and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables are generally not collateralized; however, NRG believes that the credit risk posed by industry concentration is offset by the diversification and creditworthiness of the Company's customer base.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, trust funds, receivables, accounts payables, and accrued liabilities approximate fair value because of the short-term maturity of these instruments. The carrying amounts of long-term receivables usually approximate fair value, as the effective rates for these instruments are comparable to market rates at year-end, including current portions. Any differences are disclosed in Note 5, *Financial Instruments.* The fair value of long-term debt is estimated based on quoted market prices for those instruments that are publicly traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Asset Retirement Obligations

NRG has adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, or SFAS 143, which requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, while the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. In addition, NRG has also identified conditional asset retirement obligations for asbestos removal and disposal, which are specific to certain power generation operations. Under FIN 47, a conditional asset retirement obligation is reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset, (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique.

These asset retirement obligations are primarily related to the future dismantlement of equipment on leased property and environment obligations related to nuclear decommissioning, ash disposal site closures, and fuel storage facilities. See Note 22, *Regulatory Matters,* for a further discussion of NRG's nuclear decommissioning obligations.

The following table represents the balances of the asset retirement obligation as of December 31, 2006 and 2005, and the additions and accretion related to the Company's asset retirement obligation for the year ended December 31, 2006.

	Total (In millions)
Balance as of December 31, 2005	$ 28
Additions — acquisitions	315
Additions — incurred during the year	12
Additions — due to revisions in cash flow	3
Accretion	23
Balance as of December 31, 2006	$ 381

Pensions

NRG offers pension benefits through either a defined benefit pension plan or a cash balance plan. In addition, the Company provides postretirement health and welfare benefits for certain groups of employees. Effective December 31, 2006, NRG accounts for pension and other postretirement benefits in accordance with SFAS No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106 and 132 (R)*, or SFAS 158. NRG recognizes the funded status of the Company's defined benefit plans in the statement of financial position and records an offset to other comprehensive income. In addition, NRG also recognizes on an after tax basis, as a component of other comprehensive income, gains and losses as well as all prior service costs that have not been included as part of the Company's net periodic benefit cost. The determination of NRG's obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. NRG's actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by the Company.

Stock Based Compensation

On January 1, 2006, NRG transitioned from SFAS No. 123, *Accounting for Stock-Based Compensation*, or SFAS 123, and adopted SFAS No. 123 (Revised 2004), *Share-Based Payment*, or SFAS 123(R), using the modified prospective method. Under the modified prospective method, NRG applied the provisions of SFAS 123(R) to new awards of stock-based compensation and to awards modified, repurchased, or cancelled after the required effective date. SFAS 123(R) requires that NRG apply a forfeiture rate to existing awards and apply the standard's fair value recognition provisions. The fair value of the Company's non-qualified stock options and performance units are estimated on the date of grant using the Black-Scholes option-pricing model and the Monte Carlo valuation model, respectively. NRG uses the Company's common stock price on the date of grant as the fair value of the Company's restricted stock units and deferred stock units. The Company recognizes compensation expense for both graded and cliff vesting awards on a straight-line basis over the requisite service period for the entire award. Upon the adoption of SFAS 123(R), NRG applied a forfeiture rate to the Company's existing awards and recognized in the Company's statement of operations approximately $1.9 million, or $1.1 million, net of tax, as a reduction to compensation expense for the year ended December 31, 2006.

Investments Accounted for by the Equity Method

NRG has investments in various international and domestic energy projects. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents NRG from exercising a controlling influence over the operating and financial policies of the projects. Under this method, equity in pre-tax income or losses of domestic partnerships and, generally, in the net income or losses of international projects, are reflected as equity in earnings of unconsolidated affiliates.

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

On January 1, 2006, NRG adopted EITF Issue No. 05-5, *Accounting for Early Retirement or Post-employment Programs with Specific Features (such as terms specified in Altersteilzeit Early Retirement Arrangements)*, or EITF 05-5. EITF 05-5 provides guidance on the accounting for early retirement or post-employment programs with specific features, and specifically the terms of Altersteilzeit early retirement arrangements. The Altersteilzeit, or ATZ, arrangement is a voluntary early retirement program in Germany designed to create an incentive for employees, within a certain age group, to transition from employment into retirement before their legal retirement age. If certain criteria are met by the employer, the German government provides to the employer a subsidy for bonuses paid to the employee and the additional contributions paid by the employer into the German government pension plan under an ATZ arrangement for a maximum of six years. Upon adoption of EITF 05-5 on January 1, 2006, NRG recognized additional equity in earnings of unconsolidated affiliates of approximately $2 million, after-tax, from the Company's MIBRAG interest. This amount reflects the cumulative effect of the adoption of EITF 05-5, and did not materially affect NRG's consolidated financial position, results of operations, or statement of cash flows for the year ended December 31, 2006.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

In recording transactions and balances resulting from business operations, NRG uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of long-term energy commodity contracts, environmental liabilities, and legal costs incurred in connection with recorded loss contingencies, among others. In addition, estimates are used to test long-lived assets for impairment and to determine the fair value of impaired assets. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on the Company's net income or total stockholders' equity, as previously reported.

Recent Accounting Developments

In July 2006, the FASB issued FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109*, or FIN 48, which applies to all tax positions related to income taxes subject to SFAS 109. FIN 48 requires a new evaluation process for all tax positions taken, recognizing tax benefits when it is more-likely-than-not that a tax position will be sustained upon examination by the authorities. The benefit from a position that has surpassed the more-likely-than-not threshold is the largest amount of benefit that is more than 50% likely to be realized upon settlement. Differences between the amounts recognized in the statement of financial position prior to the adoption of FIN 48 and the amounts reported after adoption are to be accounted for as an adjustment to the beginning balance of retained earnings. The Company has completed its evaluation of the impact of the January 1, 2007, adoption of FIN 48 and determined that such adoption will not have a material impact on the Company's financial position, results from operations, and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* or SFAS 157. This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. Upon implementation, this guidance is not expected to have a material effect on the Company's consolidated financial position, statements of operations, and cash flows.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108,* provides guidance on how the effects of the carryover or reversal of prior year uncorrected misstatements should be considered in quantifying a current year misstatement. SAB 108 requires entities to quantify misstatements using both a roll-over method, which focuses on correcting the income statement as of the reporting date, and an iron-curtain method, which focuses on correcting the balance sheet as of the reporting date. NRG's adoption of SAB 108 on December 31, 2006 had no impact on the Company's consolidated financial position, results of operations, or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities-including an amendment of FASB Statement No. 115,* or SFAS 159. This statement provides entities with an option to measure and report selected financial assets and liabilities at fair value. This statement requires a business entity to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. An entity may decide whether to elect the fair value option for each eligible item on its election date, subject to certain requirements described in the statement. This Statement will be effective for NRG as of January 1, 2008. Upon implementation, any remeasurement to fair value on the effective date for chosen eligible items shall be recorded as an adjustment to opening retained earnings. NRG is currently assessing the impact that SFAS 159 may have on its consolidated financial position.

Note 3 — Business Acquisitions and Dispositions

Acquisition of Texas Genco LLC

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

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

One of NRG's principal reasons for making acquisitions is to improve the Company's position in deregulated generation markets. NRG believes that the acquisition of Texas Genco LLC presented an opportunity for NRG to become a meaningful player in the ERCOT market, a competitive market with stable regulation and forecasted demand growth. NRG Texas is the second-largest generation company in the ERCOT market and the largest owner of power plants in Houston. As of December 31, 2006, NRG's Texas region operated 52 generating units at nine power generation plants, including an undivided 44% interest in two nuclear generation units at STP. The aggregate net generation capacity at NRG's Texas region is approximately 10,760 MW, which includes approximately 5,280 MW of low marginal cost solid fuel and nuclear powered baseload plants.

The acquisition of Texas Genco LLC was accounted for using the purchase method of accounting and, accordingly, the purchase price was allocated to the assets acquired and liabilities assumed based on the estimated fair value of such assets and liabilities as of February 2, 2006. The excess of the purchase price over the fair value of the net tangible and identified intangible assets acquired was recorded as goodwill. The allocation of the purchase price may be adjusted if additional information for certain income tax items become available.

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

	February 2, 2006
	(In millions)
ASSETS	
Current and non-current assets	$ 832
Coal inventory	33
In-market contracts:	
Power contracts	39
Water contracts	64
Fuel contracts	171
Emission allowances	880
Property, plant and equipment	9,336
Deferred tax asset	2,868
Goodwill	1,782
Total assets acquired	16,005
LIABILITIES	
Current and non-current liabilities	935
Pension and post-retirement liability	222
Out-of-market contracts:	
Coal	93
Gas swaps	472
Power contracts	2,100
Deferred tax liability	3,217
Long term debt	2,735
Total liabilities assumed	9,774
Net assets acquired	$ 6,231

Goodwill — The acquisition of Texas Genco LLC included an element of premium, or goodwill, due to favorable market conditions for the acquired solid fuel plants — Parish (coal), Limestone (lignite/coal), and STP (nuclear). These plants have a substantial fuel cost advantage relative to natural gas-fired plants, with current and expected continuation of elevated natural gas prices. Power prices in the ERCOT market are largely driven by natural gas prices as the marginal market power requirements are met by gas-fired plants. It is expected that this will continue for the foreseeable future in ERCOT, since a substantial portion of power generation is gas-fired and the

Company believes that it will require an extended period of time to transition to alternative fuels that could have an effect on future price expectations. As such, the above-mentioned plants will benefit from higher power prices, which are driven by the price of natural gas and the relatively low cost of coal and nuclear fuel for an extended period of time. These favorable market conditions are not considered as separable intangible assets and are, therefore, the major contributor to the amount of goodwill.

The following table summarizes the change in the value of goodwill during the nine month period ended December 31, 2006:

	(In millions)
Goodwill balance at March 31, 2006	$ 2,748
Increase in fixed assets per revised valuation	(906)
Net decrease in intangibles and other contracts per revised valuation	215
Adjustment to deferred tax assets and liabilities	(275)
Change in goodwill due to changes in valuation	(966)
Goodwill balance at December 31, 2006	$ 1,782

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

- Change in assumptions and estimates in the price of electricity, coal, gas and emission allowances;
- The tax basis of the assets and liabilities acquired; and
- More precise information with respect to identifiable tangible and intangible assets.

Acquisition of Remaining 50% interest in WCP

On March 31, 2006, NRG completed a purchase and sale agreement for projects co-owned with Dynegy, Inc. Under the agreements, NRG acquired Dynegy's 50% ownership interest in WCP (Generation) Holdings, Inc., or WCP, for $205 million, and NRG became the sole owner of WCP's 1,825 MW of generation capacity in Southern California. In addition, NRG sold to Dynegy the Company's 50% ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. NRG sold Rocky Road for a fair value sale price of $45 million, paying Dynegy a net purchase price of $160 million at closing. Prior to the purchase, NRG had an existing investment in WCP accounted for as an equity method investment, or Original Investment.

One of NRG's principal reasons for making acquisitions is to improve the Company's position in deregulated generation markets. NRG believes that the acquisition of the remaining interest in WCP presents an opportunity for NRG to become a meaningful player in the CAISO market, a market with stable forecasted demand growth. The acquisition of the remaining 50% interest in WCP, or New Investment, was accounted for as a step acquisition since the Original Investment was transacted in a prior period. As a result, the value of the Original Investment and the purchase price of the New Investment were determined and allocated separately. The value of the Original Investment was based on the book value of approximately $159 million as of the date of the acquisition of the New Investment.

The value of the New Investment was allocated based on the estimated fair value of assets acquired and liabilities assumed as of March 31, 2006. The purchase price allocation reflected an excess of fair value of the net assets acquired over the purchase price of the New Investment, resulting in negative goodwill of approximately $46 million. The negative goodwill was subsequently allocated as a reduction to the fair value of WCP's fixed assets. Once the WCP asset appraisals are final, the purchase price allocation may change from the amounts included herein based on the results of the final appraisal and an analysis of the income tax effect on the acquisition.

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

	Original Investment	New Investment: Fair Value Before Negative Goodwill Allocation	New Investment: Allocation of Negative Goodwill	New Investment: Fair Value after Negative Goodwill Allocation	Purchase Price Allocation
			(In millions)		
Current assets	$ 148	$ 153	$ —	$ 153	$ 301
Property, plant and equipment	24	102	(39)	63	87
Intangible assets	2	20	(7)	13	15
Other non-current assets	—	8	—	8	8
Current liabilities	(12)	(11)	—	(11)	(23)
Non-current liabilities	(3)	(21)	—	(21)	(24)
Negative goodwill	—	(46)	46	—	—
Total Equity	$ 159	$ 205	$ —	$ 205	$ 364

Unaudited Supplemental Pro Forma Information

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

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In millions)	
Operating revenues	$5,884	$5,891
Net income	399	296
Earnings per share — Basic	2.59	1.74
Earnings per share — Diluted	2.53	1.72
Weighted average number of shares outstanding — Basic	133.9	140.8
Weighted average number of shares outstanding — Diluted	144	152

The pro forma net income for the year ended December 31, 2006 reflects the following nonrecurring expenses incurred by Texas Genco LLC before February 2, 2006:

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

Other Business Events

Red Bluff and Chowchilla — On January 3, 2007, NRG completed the sale of the Company's Red Bluff and Chowchilla II power plants to an entity controlled by Wayzata Investment Partners LLC. These power plants, located in California, are fueled by natural gas, with generating capacity of 45 MW and 49 MW, respectively.

Padoma — On July 14, 2006, NRG announced the completion of the acquisition of privately-held Padoma Wind Power LLC, or Padoma, a wind farm developer, whose principals have developed, financed, built, and operated wind farms in the U.S. and Europe. Padoma will maintain its headquarters in La Jolla, California and will operate as a subsidiary of NRG.

Gladstone — On June 8, 2006, NRG announced the sale of the Company's 37.5% equity interest in the Gladstone power station, or Gladstone, and its associated 100% owned NRG Gladstone Operating Services to Transfield Services, an Australia-based provider of operations, maintenance, ownership and asset management services for a purchase price of approximately $189 million (AU$239 million) subject to customary purchase price adjustments, plus assumption of NRG's share of Gladstone's unconsolidated debt and cash of approximately $61 million (AU$77 million) and approximately $28 million (AU$35 million), respectively. After-tax cash proceeds are expected to be in excess of $185 million (AU$234 million). The sale is pending until NRG satisfies certain conditions, particularly the securing of certain consents and waivers from the other owners of the project, or agrees to complete the sale on alternative terms. NRG is seeking to close the transaction in 2007.

Note 4 — Discontinued Operations

NRG has classified material business operations, and gains/losses recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for the affected businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued. NRG classifies certain assets as held-for-sale when management has committed to selling certain long lived assets within the next year. This classification does not affect prior period operating results.

SFAS 144 requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value, less costs to sell. In applying the provisions of SFAS 144, the Company's management considered cash flow analyses, bids, and offers related to those assets and businesses. In accordance with the provisions of SFAS 144, discontinued operations and assets held-for-sale are not being depreciated commencing with their classification as such. The assets and liabilities of the discontinued operations are reported in NRG's balance sheets as discontinued operations.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the major classes of assets and liabilities classified as discontinued operations as of December 31, 2006 and 2005:

	As of December 31, 2006	As of December 31, 2005
	(In millions)	
Cash and cash equivalents	$ —	$ 13
Restricted cash	—	15
Receivables, net	—	36
Inventory	—	20
Other current assets	—	26
Current assets — discontinued operations	—	110
Property, plant and equipment, net	—	545
Notes receivable	—	241
Other non-current assets	—	41
Non-current assets — discontinued operations	—	827
Current portion of long-term debt	—	6
Accounts payable — trade	—	27
Other current liabilities	—	137
Current liabilities — discontinued operations	—	170
Long-term debt	—	410
Other non-current liabilities	—	159
Non-current liabilities — discontinued operations	$ —	$ 569

The following table summarizes NRG's discontinued operations for all periods presented in the Company's consolidated financial statements:

Project	Segment(a)	Initial Discontinued Operations Treatment Date	Disposal Date
McClain	Corporate	Third Quarter 2003	Third Quarter 2004
PERC	Corporate	First Quarter 2004	Second Quarter 2004
Cobee	International	First Quarter 2004	Second Quarter 2004
Hsin Yu	International	Second Quarter 2004	Second Quarter 2004
LSP Energy (Batesville)	Corporate	Second Quarter 2004	Third Quarter 2004
NEO Corporation (NEO, Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC)	Corporate	Third Quarter 2004	Third Quarter 2004
Northbrook New York and Northbrook Energy	Corporate	Third Quarter 2005	Third Quarter 2005
Audrain	Corporate	Fourth Quarter 2005	Second Quarter 2006
Flinders	International	Second Quarter 2006	Third Quarter 2006
Resource Recovery	Corporate	Third Quarter 2006	Fourth Quarter 2006

(a) Conforms to NRG's revised segment classification

Summarized results of discontinued operations for the years ended December 31, 2006, 2005, and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Operating revenues	$189	$292	$366
Operating costs and other expenses	201	289	365
Pre-tax income/(loss) from operations of discontinued components	(12)	3	1
Income tax benefit	(2)	(3)	(8)
Income from operations of discontinued components	(10)	6	9
Disposal of discontinued components — pre-tax gain	80	13	30
Income tax expense	4	7	8
Gain on disposal of discontinued components, net	76	6	22
Income on discontinued operations, net of income taxes	$ 66	$ 12	$ 31

The pre-tax gain/(loss) on disposal of the Company's discontinued operations for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,			
	2006	2005	2004	Segment(a)
			(In millions)	
Resource Recovery	$ 5	$ —	$ —	Corporate
Flinders	60	—	—	International
Audrain	15	—	—	Corporate
Northbrook Energy, Northbrook New York	—	12	—	Corporate
McClain	—	1	(3)	Corporate
PERC	—	—	3	Corporate
Cobee	—	—	3	International
LSP Energy — Batesville	—	—	11	Corporate
Hsin Yu	—	—	10	International
NEO Corporation	—	—	6	Corporate
Total pre-tax gain on disposal of discontinued operations	$ 80	$ 13	$ 30	

(a) Conforms to NRG's revised segment classification

Resource Recovery — On November 8, 2006, NRG completed the sale of the Company's Newport and Elk River Resource Recovery facilities, Becker Ash Disposal facility as well as the Company's ownership interest in NRG Processing Solutions LLC, to Resource Recovery Technologies, LLC for total proceeds of approximately $22 million. NRG recognized a pre-tax gain of $5 million on the sale.

Flinders — On August 30, 2006, NRG announced the completion of the sale of the Company's 100% owned Flinders power station and related assets, or Flinders, located near Port Augusta, Australia, which consisted of two coal-fueled plants — Northern and Playford, with a combined generation capacity of approximately 760 MW, to Babcock & Brown Power Pty, a subsidiary of Babcock & Brown, a global investment and advisory firm. Proceeds from the sale were approximately $242 million (AU$317 million). The sale resulted in the elimination of approximately $370 million (AU$485 million) of consolidated liabilities, including approximately $183 million (AU$240 million) of non-recourse debt obligations and approximately $92 million (AU$121 million) in non-current liabilities related to obligations for the purchase of electricity and the supply of fuel to the Osborne power station that were guaranteed by NRG. NRG recognized a pre-tax gain of approximately $60 million from the sale.

Audrain — On March 29, 2006, NRG completed the sale of Audrain generating station, a gas-fired peaking facility in Vandalia, Missouri, to AmerenUE, a subsidiary of Ameren Corporation. The proceeds from the sale were $115 million, plus AmerenUE's assumption of $240 million of non-recourse capital lease obligations and assignment of a $240 million note receivable. NRG recorded a pre-tax gain of $15 million. Of the $115 million in cash proceeds, approximately $20 million was paid to NRG and the balance was paid to the lenders of NRG Financial I LLC.

Northbrook New York LLC and Northbrook Energy LLC — On August 11, 2005, NRG completed the sale of Northbrook New York LLC and Northbrook Energy LLC. In exchange for the sale, NRG received net cash proceeds of $36 million and paid off Northbrook New York LLC's third party debt of $17 million. NRG recognized a pre-tax gain of approximately $12 million in the third quarter of 2005.

McClain — On July 9, 2004, NRG McClain completed the sale of its 77% interest in the McClain Generating Station, a 520 MW combined cycle natural gas facility located in New Castle, Oklahoma, to Oklahoma Gas & Electric Company, with the Oklahoma Municipal Power Authority continuing to own the remaining 23% interest in the facility. The proceeds of $160 million from the sale were used to repay outstanding project debt under a secured term loan and working capital facility. A pre-tax loss of approximately $3 million was recognized in 2004.

Penobscot Energy Recovery Company (PERC) — In April 2004, NRG completed the sale of its interest in PERC to SET PERC Investment LLC. Upon completion of the transaction, NRG received net proceeds of $18 million, resulting in a gain of approximately $3 million.

Cobee — During the first quarter of 2004, NRG entered into an agreement for the sale of the Company's interest in the Cobee project to Globeleq Holdings Limited, which also reached financial close in April 2004. Upon completion of the transaction, NRG received net proceeds of approximately $50 million, resulting in a pre-tax gain of approximately $3 million.

LSP Energy, Batesville — On August 24, 2004, NRG completed the sale of the Company's 100% interest in an 837-MW generating plant in Batesville, Mississippi, including the assumption of approximately $300 million of outstanding project debt. The transaction resulted in the elimination of $289 million in consolidated debt from NRG's balance sheets. In exchange for the sale, NRG received cash proceeds of $28 million and recorded a pre-tax gain of $11 million in 2004.

Hsin Yu — During the second quarter of 2004, NRG entered into an agreement for the sale of the Company's interest in the Hsin Yu project to a minority interest shareholder, Asia Pacific Energy Development Company Ltd., and reached financial closing in May 2004. Completion of the transaction resulted in a pre-tax gain of approximately $10 million, resulting from the Company's negative equity in the project.

NEO Corporation — During the third quarter of 2004, NRG completed the sale of four wholly-owned entities — NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC, as well as the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC, and NEO Montauk Gasco LLC to Algonquin Power of Canada. NRG received cash proceeds of $6 million from the sale of the wholly-owned entities, which resulted in a $6 million pre-tax gain associated with the four wholly-owned entities sold. In addition, NRG received cash proceeds of $6 million for the sale of the Company's equity method investments, which resulted in a pre-tax loss of approximately $4 million. The sale of the equity method investments does not qualify for reporting purposes as discontinued operations.

Note 5 — Financial Instruments

The estimated fair values of NRG's recorded financial instruments are as follows:

	Year Ended December 31,			
	Carrying Amount		Fair Value	
	2006	2005	2006	2005
	(In millions)			
Cash and cash equivalents	$ 795	$ 493	$ 795	$ 493
Restricted cash	44	49	44	49
Trust fund investments	377	20	377	20
Notes receivable	114	103	126	173
Long-term debt, including current portion	8,777	2,505	8,828	2,632

For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments. Trust fund investments are comprised of various U.S. debt securities carried at fair market value.

The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The fair value of long-term debt is estimated based on quoted market prices for those instruments that are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Note 6 — Accounting for Derivative Instruments and Hedging Activities

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

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

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

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

Derivative Financial Instruments

Energy-Related Commodities

To manage the commodity price risk associated with the Company's competitive supply activities and the price risk associated with power sales from the Company's electric generation facilities, NRG may enter into a variety of derivative and non-derivative hedging instruments, utilizing the following:

- Forward contracts, which commit NRG to sell energy commodities or fuels 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, or notional, quantity.
- Option contracts, which convey the right to buy or sell a commodity.

The objectives for entering into derivative contracts designated as hedges include:

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

As of December 31, 2006, NRG had hedge and non-hedge energy-related derivative financial instruments, and other energy-related contracts that did not qualify as derivative financial instruments extending through December 2026. As of December 31, 2006, NRG's derivative assets and liabilities consisted primarily of the following:

- Forward and financial contracts for the sale of electricity and related products economically hedging NRG's generation assets' forecasted output through 2012.
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG's generation assets into 2017.

Also, as of December 31, 2006, NRG had other energy-related contracts that qualified for the NPNS exception and were therefore exempt from fair value accounting treatment under the guidelines established by SFAS 133 as follows:

- Power sales and capacity contracts extending to 2010.
- Coal purchase contracts extending through 2015 designated as normal purchases and disclosed as part of NRG's contractual cash obligations. See Note 21, *Commitments and Contingencies*, for further discussion.

Also, as of December 31, 2006, NRG had other energy-related contracts that did not qualify as derivatives under the guidelines established by SFAS 133 as follows:

- Load-following forward electric sale contracts extending through 2026.
- Natural gas transportation contracts and storage agreements are not derivatives and are disclosed as part of NRG's contractual cash obligations. See Note 21, *Commitments and Contingencies*, for further discussion.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company's issuance of variable and fixed rate debt. In order to manage the Company's interest rate risk, NRG enters into interest-rate swap agreements. In January 2006, in anticipation of the New Senior Credit Facility, NRG entered into a series of forward starting interest rate swaps intended to hedge the variability in cash flows associated with the debt issuance. These transactions were designated as cash flow hedges with any gains/losses deferred on the balance sheet in OCI. In February 2006, with the completion of the sale of the Senior Notes, the Company designated a fixed-to-floating interest rate swap as a hedge of fair value changes in the Senior Notes. This interest rate swap was previously designated as a hedge of NRG's 8% Second Priority Notes, which were effectively replaced by the Senior Notes.

As of December 31, 2006, all of NRG's interest rate swap arrangements had been designated as either cash flow or fair value hedges. As of December 31, 2006, NRG had interest rate derivative instruments extending through June 2019.

Foreign Currency-Related Derivative Instruments

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

For the years ended December 31, 2006, 2005 and 2004, NRG's pre-tax earnings were not materially affected by any gain or loss associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS 133.

Accumulated Other Comprehensive Income

Gains and losses attributable to hedge derivatives are reclassified from OCI to current period earnings due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged transactions are recorded. Changes in the fair values of derivatives accounted for as hedges are also recorded in OCI.

The following table summarizes the effects of SFAS 133, as amended, on NRG's accumulated other comprehensive income balance attributable to hedged derivatives for the years ended December 31, 2004, 2005 and 2006, net of tax:

	Energy-Related Commodities	Interest Rate	Total
	(In millions)		
Accumulated OCI balance at December 31, 2003	$ (2)	$ 1	$ (1)
Unwound from OCI during period — due to unwinding of previously deferred amounts	3	5	8
Changes in fair value of hedge contracts — gains/(losses)	4	(4)	—
Accumulated OCI balance at December 31, 2004	$ 5	$ 2	$ 7
Unwound from OCI during period: — due to unwinding of previously deferred amounts	132	(2)	130
Changes in fair value of hedge contracts — gains/(losses)	(341)	8	(333)
Accumulated OCI balance at December 31, 2005	$ (204)	$ 8	$(196)
Unwound from OCI during period — due to unwinding of previously deferred amounts	6	(2)	4
Changes in fair value of hedge contracts — gains	391	10	401
Accumulated OCI balance at December 31, 2006	$ 193	$ 16	$ 209
Gains expected to unwind from OCI during next 12 months, net of $42 tax	$ 64	$ —	$ 64

As of December 31, 2006, the net balance in OCI relating to SFAS 133 was an unrecognized gain of approximately $209 million, which is net of $135 million in income taxes. NRG expects $64 million of net deferred gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

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

Statement of Operations

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables summarizes the pre-tax effects of non-hedge derivatives, derivatives that no longer qualify as hedges, and ineffectiveness of hedge derivatives on NRG's statement of operations for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31, 2006		
	Energy-Related Commodities	Interest Rate	Total
	(In millions)		
Operating revenues	$ 295	$ —	$295
Cost of operations	—	—	—
Equity in earnings of unconsolidated subsidiaries	—	—	—
Interest expense	—	3	3
Total Statement of Operations impact before tax	$ 295	$ (3)	$292

For the year ended December 31, 2006, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $295 million is comprised of $172 million of fair value increases in forward sales of electricity and fuel, $90 million from the reversal of mark-to-market losses, which ultimately settled as financial revenues, and $33 million of gains associated with our trading activity. The $172 million of fair value increases in forward sales of electricity and fuel includes approximately $28 million due to the ineffectiveness associated with financial forward contracted electric and gas sales. NRG's pre-tax earnings were also affected by a $3 million loss due to ineffectiveness associated with our fixed-to-floating interest rate swap designated as a hedge of fair value changes in the Senior Notes.

Discontinued Hedge Accounting — During 2006, due to a relatively mild summer season and expected lower power generation for the remainder of 2006, NRG discontinued cash flow hedge accounting for certain contracts related to commodity prices previously accounted for as a cash flow hedge and determined forecasted sales were no longer probable. These contracts were originally entered into as hedges of forecasted sales by baseload plants. The decision not to deliver against these contracts was driven by the decline in natural gas and associated power prices, making it uneconomical to dispatch the units into the marketplace. As a result, approximately $5 million of previously deferred revenue in OCI was recognized in earnings for the year ended December 31, 2006.

	Year Ended December 31, 2005		
	Energy-Related Commodities	Interest Rate	Total
	(In millions)		
Operating revenues	$ (154)	$ —	$(154)
Cost of operations	2	—	2
Equity in earnings of unconsolidated subsidiaries	12	—	12
Interest expense	—	—	—
Total Statement of Operations impact before tax	$ (140)	$ —	$ (140)

For the year ended December 31, 2005, the unrealized loss associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $154 million is comprised of $122 million of fair value decreases in forward sales of electricity and fuel, $59 million from the reversal of mark-to-market gains, which ultimately settled as financial revenues, and $27 million of gains associated with our trading activity. The impact of hedge ineffectiveness associated with financial forward contracted electric sales was immaterial.

	Year Ended December 31, 2004		
	Energy-Related Commodities	Interest Rate	Total
	(In millions)		
Operating revenues	$ 59	$ —	$ 59
Cost of operations	—	—	—
Equity in earnings of unconsolidated subsidiaries	24	—	24
Interest expense	—	—	—
Total Statement of Operations impact before tax	$ 83	$ —	$ 83

For the year ended December 31, 2004, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $59 million is comprised of fair value changes in forward sales of electricity and fuel. No ineffectiveness was recognized on commodity cash flow hedges during the year ended December 31, 2004.

Impact of Hedge Reset — NRG accounted for the Company's Hedge Reset transaction as a net settlement of its current hedge positions and a subsequent reestablishment of new hedge positions. The impact of the net settlement reduced revenues by approximately $129 million.

As of December 31, 2006, the impact to NRG's consolidated financial position and statement of operations from the Hedge Reset transaction was as follows:

	(In millions)
Settlement payment	$ (1,347)
Reduction in derivative liability	145
Reduction in out-of-market contracts	1,073
Net decrease in revenues	$ (129)

Note 7 — Inventory

Inventory, which is stated at the lower of weighted average cost or market, consists of:

	As of December 31,	
	2006	2005
	(In millions)	
Fuel oil	$ 162	$ 131
Coal/Lignite	118	58
Natural gas	12	4
Spare parts	129	44
Other	—	3
Total Inventory	$ 421	$ 240

Note 8 — Capital Lease and Notes Receivable

Notes receivable primarily consists of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. NRG's notes receivable and capital lease as of December 31, 2006 and 2005 were as follows:

	As of December 31, 2006	As of December 31, 2005
	(In millions)	
Capital Lease Receivable — non-affiliate		
VEAG Vereinigte Energiewerke AG, due August 31, 2021, 13.88%(a)	$ 392	$ 378
Capital Lease — non-affiliates	392	378
Less current maturities	27	24
Total	365	354
Note Receivable — affiliates		
Kraftwerke Schkopau GBR, indefinite maturity date, 4.75%-7.79%(b)	114	103
Notes receivable — affiliates	$ 114	$ 103

(a) Saale Energie GmbH, or SEG, has sold 100% of its share of capacity from the Schkopau power plant to VEAG Vereinigte Energiewerke AG under a 25-year contract, which is more than 83% of the useful life of the plant. This direct financing lease receivable amount was calculated based on the present value of the income to be received over the life of the contract.

(b) SEG entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between Saale and E.On Kraftwerke GmbH. The note was used to fund SEG's initial capital contribution to the partnership and to cover project liquidity shortfalls during construction of the Schkopau power plant. The note is subject to repayment upon the disposition of the Schkopau plant.

Note 9 — Property, Plant, and Equipment

NRG's major classes of property, plant, and equipment as of December 31, 2006 and 2005 were as follows:

	As of December 31, 2006	As of December 31, 2005	Depreciable Lives	Average Remaining Useful Life
	(In millions)			
Facilities and equipment	$11,696	$2,769	1-40 Years	21
Land and improvements	561	114		
Nuclear fuel	159	—	5 Years	
Office furnishings and equipment	80	21	2-10 Years	6
Construction in progress	88	37		
Total property, plant and equipment	12,584	2,941		
Accumulated depreciation	(984)	(332)		
Net property, plant and equipment	$ 11,600	$2,609		

Note 10 — Goodwill and Other Intangibles

Goodwill —In connection with the acquisitions of Texas Genco LLC and Padoma Wind Power, LLC, NRG has recorded goodwill in the amount of approximately $1.8 billion. Goodwill is not amortized but instead tested for impairment in accordance with SFAS 142 at the reporting-unit level. Goodwill is tested annually, typically during the fourth quarter, or more often if events or circumstances, such as adverse changes in the business climate, indicate there may be an impairment. As of December 31, 2006, there was no impairment to goodwill. As of

December 31, 2006, NRG had approximately $991 million of goodwill that is deductible for U.S. income tax purposes in future periods.

Negative Goodwill — As discussed in Note 3, *Business Acquisitions and Dispositions,* NRG's acquisition of Dynegy's 50% interest in WCP reflected an excess of the fair value of the net assets acquired over the purchase price, which resulted in negative goodwill of approximately $46 million. This negative goodwill was subsequently allocated as a reduction to the fair value of WCP's non-current assets.

Intangible Assets — NRG acquired intangible assets as part of the Company's acquisition of Texas Genco LLC and established intangible assets upon adoption of Fresh Start reporting. These intangible assets include SO_2 and NO_x emission allowances and certain in-market power, fuel (coal, gas, and nuclear) and water contracts. The emission allowances are amortized and recorded as part of the cost of operations, with NO_x emission allowances amortized on a straight line basis and SO_2 emission allowances amortized based on units of production. The contracts are amortized based on contracted volumes over the life of each contract. The power contracts are amortized and recorded as part of revenues, while fuel and water contracts are amortized and recorded as part of the cost of operations.

NRG actively trades portions of the Company's emission allowances as part of the Company's asset optimization strategy, with their respective costs expensed when sold. Emission allowances that the Company designates for such trading are reclassified to intangible assets held-for-sale on the balance sheet and are not amortized.

The following tables summarize the components of NRG's intangible assets subject to amortization for the years ended December 2006 and 2005:

December 31, 2006	Emission Allowances	Contracts			Total
		Power	Fuel	Water	
	(In millions)				
January 1, 2006	$ 280	$ 56	$ —	$ —	$ 336
Acquisitions	894	39	171	64	1,168
Transfer to held for sale	(23)	—	—	—	(23)
Tax adjustments	(238)	(3)	—	—	(241)
Adjusted gross amount	913	92	171	64	1,240
Less accumulated amortization	(74)	(92)	(65)	(28)	(259)
Net carrying amount	$ 839	$ —	$106	$ 36	$ 981

December 31, 2005	Emission Allowances	Contracts			Total
		Power	Fuel	Water	
	(In millions)				
January 1, 2005	$ 292	$ 57	$—	$ —	$ 349
Sales	(5)	—	—	—	(5)
Tax adjustments	(7)	(1)	—	—	(8)
Adjusted gross amount	280	56	—	—	336
Less accumulated amortization	(30)	(49)	—	—	(79)
Net carrying amount	$ 250	$ 7	$—	$ —	$257

In accordance with SOP 90-7, any future income tax benefits realized from reducing the valuation allowance should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid-in capital. For the year ended December 31, 2006, NRG reduced its valuation allowance by approximately

$231 million and reduced a related deferred tax liability by $10 million, offset against the Company's intangible assets, in accordance with SOP 90-7. For the year ended December 31, 2005, NRG reduced its valuation allowance by approximately $17 million and reduced certain deferred tax assets by $9 million, offset against the Company's intangible assets, in accordance with SOP 90-7.

The following table presents NRG's amortization of intangible assets for the years ended December 31, 2006, 2005 and 2004:

Amortization	2006	2005	2004
		(In millions)	
Emission allowances	$ 44	$ 12	$ 18
Fuel contracts	65	—	—
Water contracts	28	—	—
Total amortization in cost of operations	$137	$ 12	$ 18
Power contract amortization recorded as a reduction to operating revenues	$ 43	$ 12	$ 32

The following table presents estimated amortization related to NRG's emission allowances and in-market contracts:

Year Ended December 31,	Emission Allowances	Contracts Fuel	Contracts Water	Total
		(In millions)		
2007	$ 42	$ 41	$ 36	$119
2008	42	21	—	63
2009	42	26	—	68
2010	56	6	—	62
2011	56	2	—	58

The weighted average remaining amortization period is 3.2 years for fuel contracts and one year for water contracts. Emission allowances are amortized based on a mix of a straight line and actual emissions emitted from the respective plants.

Intangible assets held for sale — NRG records the Company's bank of emission allowances as part of the Company's intangible assets. From time to time, management may authorize the transfer from the Company's emission bank to intangible assets held-for-sale as part of the Company's asset optimization strategy. As of December 31, 2006, the value of emission allowances held-for-sale is $79 million and is managed by the Corporate segment. Once transferred to held-for-sale, these emission allowances transferred are prohibited from moving back to held-for-use.

Out-of-market contracts — Due to Fresh Start accounting, as well as the acquisition of Texas Genco LLC, NRG acquired certain out-of-market contracts. These are primarily power, gas swaps, and certain coal contracts and are classified as non-current liabilities on NRG's consolidated balance sheet. Both the gas swap and power contracts are amortized to revenues, while the coal contracts are amortized to cost of operation. As a result of the Company's Hedge Reset transaction, NRG reset to market approximately $1.2 billion of out-of-market power and gas swap contracts reflected as a reduction to the outstanding balance.

The following table summarizes the estimated amortization related to NRG's out-of-market contracts:

Year Ended December 31,	Coal	Gas Swaps	Power Contracts	Total
2007	$ 20	$ —	$ 240	$260
2008	32	11	279	322
2009	19	34	79	132
2010	8	28	27	63
2011	2	—	20	22

Note 11 — Debt and Capital Leases

Long-term debt and capital leases consist of the following:

	As of December 31, 2006	As of December 31, 2005	Interest Rate
	(In millions except rates)		
NRG Recourse Debt:			
Senior notes due 2017	$ 1,100	$ —	7.375
Senior notes due 2016	2,400	—	7.375
Senior notes due 2014[(a)]	1,183	—	7.25
ML note payable	11	—	L+1.9[(h)]
Term loan due 2013	3,148	—	L+2.0[(h)]
2nd priority notes redeemed 2006[(b)]	—	1,074	8.00
Promissory note, Xcel Energy, due 2006[(c)]	—	10	3.00
Term loan[(d)]	—	445	—
Funded letter of credit[(d)]	—	350	—
NRG Non-Recourse Debt:			
CSF non-recourse obligations due 2008 and 2009	333	—	5.45-13.23
NRG Peaker Finance Co. LLC, due June 2019[(e)]	240	240	L+1.07[(h)]
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013 and 2017[(f)]	107	116	7.12-7.31
Camas Power Boiler LP, unsecured term loan, due June 2007	1	4	L+0.69[(h)]
Camas Power Boiler LP, revenue bonds, due August 2007	2	3	3.38
ITISA, due December 2013	32	30	12.00
ITISA, due January 2012	19	19	
Capital leases:			
Saale Energie GmbH, Schkopau capital lease, due 2021	199	214	
Other	2	—	—
Subtotal	8,777	2,505	
Less current maturities[(g)]	130	95	
Total	$8,647	$ 2,410	

(a) Includes fair value adjustment as of December 31, 2006 reflects $(17) million reduction for an interest rate swap. The swap was re-designated from the retired 2nd priority note to this note as part of the financing related to the Texas Genco LLC acquisition.

(b) Includes discount of $(6) million as of December 31, 2005. 2nd priority notes were retired in 2006.

(c) Promissory note was paid to Xcel Energy in June 2006.

(d) Terminated in 2006.

(e) Includes discount of $(50) million and $(57) million as of December 31, 2006 and 2005 respectively.

(f) Includes premium of $4 million and $5 million as of December 31, 2006 and 2005 respectively.

(g) Includes premium of $6 million.

(h) L+ equals LIBOR plus x%

NRG Recourse Debt

Senior Notes Related to the Texas Genco LLC Acquisition

On February 2, 2006, NRG completed the sale of (i) $1.2 billion aggregate principal amount of 7.25% senior notes due 2014, or 7.25% Senior Notes, and (ii) $2.4 billion aggregate principal amount of 7.375% senior notes due 2016, or 7.375% Senior Notes, collectively referred to as the Senior Notes. The Senior Notes were issued under an Indenture, dated February 2, 2006, or the Indenture, between NRG and Law Debenture Trust Company of New York, as trustee, as supplemented by a First Supplemental Indenture, dated February 2, 2006, between NRG, the Guarantors named therein, and the Trustee, relating to the 7.25% Senior Notes, and as supplemented by a Second Supplemental Indenture, dated February 2, 2006, between NRG, the Guarantors named therein, and the Trustee, relating to the 7.375% Senior Notes. On March 14, 2006, NRG executed a Third Supplemental Indenture and a Fourth Supplemental Indenture, whereby the recently acquired Texas region subsidiaries were added as Guarantors. On April 28, 2006, NRG executed a Fifth Supplemental Indenture and a Sixth Supplemental Indenture, whereby the recently acquired WCP subsidiaries were added as Guarantors. On November 13, 2006, NRG executed the Seventh and Eighth Supplemental Indentures, whereby the recently acquired Padoma 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.

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

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

The following table sets forth the premium upon redemption after February 1, 2010 for the 7.25% Senior Notes:

Redemption Period	Premium as Defined Above
February 1, 2010 to February 1, 2011	103.625%
February 1, 2011 to February 1, 2012	101.813%
February 1, 2012 and thereafter	100.000%

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

The following table sets forth the premium upon redemption after February 1, 2011 for the 7.375% Senior Notes due February 1, 2016:

Redemption Period	Premium as Defined Above
February 1, 2011 to February 1, 2012	103.688%
February 1, 2012 to February 1, 2013	102.458%
February 1, 2013 to February 1, 2014	101.229%
February 1, 2014 and thereafter	100.000%

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

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

- return of capital to shareholders;
- grant liens on assets to lenders; and
- incur additional debt.

Senior Notes Related to Hedge Reset Transaction

On November 21, 2006, NRG completed the sale of $1.1 billion aggregate principal amount of 7.375% Senior Notes due 2017. The Senior Notes were issued under an Indenture, dated February 2, 2006, among NRG and Law Debenture Trust Company of New York, as trustee, or the Trustee, as supplemented by a Ninth Supplemental Indenture, dated November 21, 2006 among NRG, the Guarantors named therein, and the Trustee, relating to these 7.375% Senior Notes. The Ninth Supplemental Indenture and the form of the notes provide, among other things, that these Senior Notes will be senior unsecured obligations of NRG.

NRG used the net proceeds from these Senior Notes and cash on hand to fund payments to counterparties under certain of the Company's existing long-term hedging agreements pursuant to agreements to reset the hedge price levels to current market prices. Interest is payable on the Senior Notes on January 15 and July 15 of each year beginning on July 15, 2007, until their maturity date of January 15, 2017.

NRG may redeem up to 35% of the notes issued prior to January 15, 2012, with net cash proceeds of certain equity offerings at a price of 107.375%, provided at least 65% of the aggregate principal amount of the notes issued remaining outstanding after the redemption. Prior to January 15, 2012, NRG may redeem all or a portion of the Senior Notes at a price equal to 100% of the principal amount of the notes redeemed, plus a premium and any accrued and unpaid interest. In addition, on or after January 15, 2012, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth below, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date of February 1, 2012.

The following table sets forth the premium upon redemption after February 1, 2012 for the 7.375% Senior Notes due January 15, 2017:

Redemption Period	Premium as Defined Above
February 1, 2012 to February 1, 2013	103.688%
February 1, 2013 to February 1, 2014	102.458%
February 1, 2014 to February 1, 2015	101.229%
February 1, 2015 and thereafter	100.000%

ML Note — As part of the Company's Hedge Reset transactions, NRG negotiated an $11 million note with Merrill Lynch. The note is subordinated to NRG's second lien structure. It bears interest at a floating rate equal to Libor plus 1.9%. The note matures on November 1, 2013. The note does not allow for an optional prepayment; however, Merrill Lynch has the option to require prepayment on the first anniversary of the closing date of November 1, 2006.

Senior Credit Facility

On February 2, 2006, NRG entered into a senior secured credit facility, or the Senior Credit Facility, with a syndicate of financial institutions, including Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley & Co., Inc., as collateral agent, and Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc. as joint lead book-runners, joint lead arrangers, and co-documentation agents, providing up to an aggregate amount of $5.575 billion. The Senior Credit Facility consisted of a $3.575 billion senior first priority secured term loan, 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 Senior Credit Facility replaced NRG's then existing senior secured credit facility. The Term Loan Facility matures on February 1, 2013 and will amortize in 27 consecutive equal quarterly installments of 0.25% of the original principal amount of the Term Loan Facility, beginning June 30, 2006, with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011.

On November 21, 2006, NRG amended this Senior Credit Facility, increasing to $1.5 billion the Letter of Credit Facility as part of the Company's Hedge Reset transactions. In addition, NRG amended certain terms and provisions within the existing credit agreement in order to provide the Company with more financial flexibility, and to help support the Company's *Repowering NRG* program and its Capital Allocation Program. As part of the amendment, NRG inserted a provision, which results in an increased level of mandatory first lien debt repayment each year. Beginning 2008, NRG must offer a portion of its excess cash flow, an amount which approximates the Company's free cash flow for the prior year, to its first lien lenders. The percentage of the excess cash flow offered to these lenders is dependent upon the Company's consolidated leverage ratio at the end of the preceding year. Of the amount offered, the first lien lenders must accept 50%, while the remaining 50% may either be accepted or rejected at the lenders' option.

The Letter of Credit Facility will mature on February 1, 2013 and no amortization will be required in respect thereof. As of December 31, 2006, NRG had approximately $3.1 billion outstanding under the Company's Term Loan Facility. As of December 31, 2006, NRG had issued $967 million under the Company's Letter of Credit Facility and $145 million in letters of credit under the Company's Revolving Credit Facility.

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

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

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

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments, loans and advances; and
- return capital to shareholders.

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

Interest Rate Swaps — In anticipation of the Senior Credit Facility, in January 2006, NRG entered into a series of forward-setting interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives quarterly the equivalent of a floating interest payment based on a 3-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps is approximately $2.2 billion.

The notional amounts and maturities of each tranche of these swaps as of December 31, 2006 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

NRG Non-Recourse Debt

Debt Related to Capital Allocation Program

During the third quarter 2006, the Company formed two wholly-owned unrestricted subsidiaries, NRG Common Stock Finance I, LLC, or CSF I, and NRG Common Stock Finance II, LLC, or CSF II, that are both consolidated by NRG. Their purpose is to repurchase shares of NRG's common stock in the public markets or in privately negotiated transactions in connection with Phase I of the Company's Capital Allocation Program. Phase I was a $500 million stock repurchase program, which was completed on October 13, 2006, with total common stock repurchased of 10,587,700 shares. These subsidiaries were funded with a combination of cash from NRG and a mix of notes and preferred interests issued to Credit Suisse. Both the notes and the preferred interests are non-recourse debt to NRG or any of its restricted subsidiaries, with the notes collateralized by the NRG common stock repurchased by these two wholly-owned unrestricted subsidiaries that are consolidated in the Company's statement of financial position. In addition, the assets of these two subsidiaries are not available to the creditors of NRG and the Company's other subsidiaries.

Notes — As of December 31, 2006, CSF I and CSF II issued a total of $249 million in notes in connection with Phase I of the Capital Allocation Program that will mature in two tranches: $137 million in October 2008, plus accrued interest at an annual rate of 5.45%, and the balance of $112 million in October 2009, plus accrued interest at an annual rate of 6.11%.

Preferred Interests — As of December 31, 2006, total preferred interests issued and outstanding by CSF I and CSF II were approximately $84 million to Credit Suisse. These preferred interests are classified as a liability per SFAS 150, because they embody a fixed unconditional obligation that these two unrestricted subsidiaries must settle. The preferred interests also mature in two tranches: $53 million in October 2008, plus accrued interest at an annual rate of 12.65%, and $31 million in October 2009, plus accrued interest at an annual rate of 13.23%.

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that remain outstanding as of December 31, 2006. The indebtedness described below is non-recourse to NRG, unless otherwise noted.

Peakers

In June 2002, NRG Peaker Financing LLC, or Peakers, an indirect wholly-owned subsidiary, issued $325 million in floating rate bonds due June 2019. Peakers subsequently swapped such floating rate debt for fixed rate debt at an all-in cost of 6.67% per annum. Principal, interest, and swap payments are guaranteed by XL Capital Assurance, through a financial guaranty insurance policy. These notes are also secured by, among other things, substantially all of the assets of and membership interests in Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, NRG Rockford LLC, NRG Rockford II LLC, and NRG Rockford Equipment LLC. As of December 31, 2006, approximately $290 million in principal remained outstanding on these bonds. Upon emergence from bankruptcy, NRG issued a $36 million letter of credit to the Peakers' Collateral Agent. The letter of credit may be drawn if the project is unable to meet principal or interest payments. There are no provisions requiring NRG to replenish the letter of credit if it is drawn.

NRG Thermal

NRG owns and operates its thermal business through a wholly-owned subsidiary holding company, NRG Thermal LLC, or NRG Thermal. In August 1993, the predecessor entity to NRG Thermal's largest subsidiary, NRG Energy Center Minneapolis LLC, or NRG Thermal Minneapolis, issued $84 million of 7.31% senior secured notes due June 2013, of which approximately $42 million remained outstanding as of December 31, 2006. In July 2002, NRG Thermal Minneapolis issued an additional $55 million of 7.25% Series A notes due August 2017, of which approximately $45 million remained outstanding as of December 31, 2006, and $20 million of 7.12% Series B notes due August 2017, of which approximately $16 million remained outstanding as of December 31, 2006. This indebtedness is secured by substantially all of the assets of NRG Thermal Minneapolis. NRG Thermal has guaranteed the indebtedness, and its guarantee is secured by a pledge of the equity interests in all of NRG Thermal's subsidiaries.

Itiquira Energetica S.A., or ITISA

On July 15, 2004, ITISA, a majority-owned subsidiary of NRG, executed a long-term financing arrangement with União de Bancos Brasilieros S.A., or Unibanco, for a 55 million Brazilian Reals term loan maturing in January 2012. The facility bears a floating interest rate and amortizes on a schedule that is indexed to certain foreign exchange rates. The principal obligation as of December 31, 2006 was approximately $19 million. Additionally, Eletrobrãs owns preferred shares in ITISA, which for U.S. GAAP purposes are reflected as debt. The preferred shares accrue cumulative dividends of 12% per year, payable only at such time ITISA has sufficient retained profits or reserves. The balance as of December 31, 2006 was approximately $32 million.

Capital Leases

Saale Energie GmbH

Saale Energie GmbH, or SEG, an NRG wholly-owned subsidiary, has a 41.9% participation in the Schkopau Power Plant, or Schkopau, through NRG's interest in the Kraftwerke Schkopau GbR, or KSGbR, partnership. Under the terms of a Use and Benefit Fee Agreement, SEG and the other partner to the project, E.ON Kraftwerke GmbH, are required to fund debt service and certain other costs resulting from the construction and financing of Schkopau. The Use and Benefit Fee Agreement is treated as a capital lease under U.S. GAAP. Calls for funds are made to the partners based on their participation interest as cash is needed. The KSGbR issued debt to fund Schkopau pursuant to multiple facilities totaling approximately €785 million (approximately $1 billion). As of December 31, 2006, approximately €300 million (approximately US $396 million) remained outstanding at Schkopau. Interests on the individual loans accrue at fixed rates averaging 5.47% per annum, with maturities occurring between 2007 and 2015. The lenders to the project rely almost exclusively on the creditworthiness of E.ON Kraftwerke GmbH. SEG remains liable to the lenders as a partner in KSGbR, but there is no recourse to NRG. As of December 31, 2006, the capital lease obligation at SEG was approximately $199 million.

Debt Extinguishment

Cash Tender Offer and Consent Solicitation

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

Debt Reduction Related to Capital Allocation Program

On December 29, 2006, NRG repaid $400 million of the Company's Term Loan facility, completing the debt reduction portion of the Company's previously announced Capital Allocation Program. NRG used cash on hand to fund the repayment.

Debt of Discontinued Operations

As discussed in Note 4, *Discontinued Operations*, on August 30, 2006, NRG completed the sale of Flinders to Babcock and Brown of Australia. The sale resulted in the elimination of approximately $183 million (AU$240 million) of non-recourse debt.

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

NRG Promissory Note

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

Consolidated Annual Maturities and Future Minimum Lease Payments

Annual payments based on the maturities of NRG's long-term debt and capital leases for the years ending after December 31, 2006 are as follows:

	(In millions)
2007	$ 136
2008	287
2009	236
2010	86
2011	82
Thereafter	8,013
Total	$ 8,840

NRG's future minimum lease payments for capital leases included above as of December 31, 2006 are as follows:

	(In millions)
2007	$ 87
2008	47
2009	38
2010	22
2011	13
Thereafter	196
Total minimum obligations	403
Interest	202
Present value of minimum obligations	201
Current portion	70
Long-term obligations	$ 131

Note 12 — Benefit Plans and Other Postretirement Benefits

Substantially all employees hired prior to December 5, 2003 were eligible to participate in NRG's defined benefit pension plans. The Company initiated a noncontributory, defined benefit pension plan effective January 1, 2004, with credit for service from December 5, 2003. In addition, the Company provides postretirement health and welfare benefits for certain groups of employees. Generally, these are groups that were acquired prior to 2004 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. NRG expects to contribute approximately $108 million to the Company's three pension plans in 2007.

In September 2006, the FASB issued SFAS 158. This statement requires an employer that sponsors one or more single-employer defined benefit plans to recognize the funded status of a benefit plan in its statement of financial position with an offset to other comprehensive income, and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. NRG adopted this statement as of the Company's fiscal year ended December 31, 2006.

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

NRG's Texas region employees are also covered under an unfunded postretirement health and welfare plan. Each year, employees receive a fixed credit of $750 to their account plus interest. Certain grandfathered employees will receive additional credits through 2008. At retirement, the employees may use their accounts to purchase retiree medical and dental benefits from NRG. NRG's costs are limited to the amounts earned in the employee's account; all other costs are paid by the participant. The net periodic pension cost relating to the Texas region's defined benefit plan for the period ended December 31, 2006 was $11 million, and $2 million for the period ended December 31, 2006 for its other postretirement benefit plans. These amounts are included in the tables below.

Defined Benefit Plans

The net annual periodic pension cost related to NRG domestic pension and other postretirement benefit plans include the following components:

	Year Ended December 31,		
	Pension Benefits		
	2006	2005	2004
	(In millions)		
Service cost benefits earned	$ 17	$ 11	$ 11
Interest cost on benefit obligation	15	4	3
Expected return on plan assets	(7)	—	—
Curtailment gain	—	—	(1)
Net periodic benefit cost	$ 25	$ 15	$ 13

	Year Ended December 31, Other Postretirement Benefits		
	2006	2005	2004
	(In millions)		
Service cost benefits earned	$ 3	$ 2	$ 1
Interest cost on benefit obligation	4	3	3
Net periodic benefit cost	$ 7	$ 5	$ 4

A comparison of the pension benefit obligation and pension assets as of December 31, 2006 and 2005 for all of NRG's plans on a combined basis is as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(In millions)			
Benefit obligation at January 1	$ 318	$ 64	$ 80	$ 51
Service cost	17	11	3	2
Interest cost	15	4	4	3
Plan initiation	—	—	—	—
Plan amendments	—	—	—	—
Plan curtailment	—	—	—	—
Actuarial (gain)/loss	(29)	5	(6)	2
Benefit payments	(27)	(1)	(1)	(1)
Benefit obligation at December 31	$ 294	$ 83	$ 80	$ 57
Fair value of plan assets at January 1	86	1	—	—
Actual return on plan assets	14	—	—	—
Employer contributions	51	13	1	1
Benefit payments	(28)	(1)	(1)	(1)
Fair value of plan assets at December 31	$ 123	$ 13	$ —	$ —
Funded status at December 31 — excess of obligation over assets	(171)	(70)	(80)	(57)
Unrecognized net (gain) loss	—	8	—	8
Accrued benefit liability recognized on the consolidated balance sheet at December 31	$(171)	$(62)	$ (80)	$ (49)

Amounts recognized in NRG's balance sheets were as follows:

	As of December 31,			
	Pension Benefits		Other Post-Employment Benefits	
	2006	2005	2006	2005
	(In millions)			
Assets	$ —	$ —	$ —	$ —
Current liabilities	—	—	—	—
Non-current liabilities	171	62	80	49

Amounts recognized in NRG's accumulated other comprehensive income were as follows:

	As of December 31,			
	Pension Benefits		Other Post-Employment Benefits	
	2006	2005	2006	2005
	(In millions)			
Unrecognized gain/(loss)	$(26)	$ —	$ 1	$ —
Total	(26)	—	1	—

The following table presents the balances of significant components of NRG's domestic pension plan:

	Pension Benefits	
	2006	2005
	(In millions)	
Projected benefit obligation	$ 294	$ 83
Accumulated benefit obligation	226	35
Fair value of plan assets	123	13

The following table summarizes the incremental effect of applying SFAS 158 to certain line items on NRG's consolidated financial position as of December 31, 2006:

	Before Application of SFAS 158	Adjustments	After Application of SFAS 158
		(In millions)	
Liability for pension and other post employment benefits	$ 326	$ (25)	$ 301
Deferred income tax liabilities	544	10	554
Total liabilities	13,544	(15)	13,529
Accumulated other comprehensive income	267	15	282
Total stockholders' equity	$ 5,634	$ 15	$ 5,658

The following table presents the significant assumptions used to calculate NRG's benefit obligations:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
Weighted-Average Assumptions	2006	2005	2006	2005
Discount rate	5.92%	5.50%	5.92%	5.50%
Rate of compensation increase	4.00-4.50%	4.00-4.50%	—	—
Health care trend rate	—	—	10.5% grading to 5.5% in 2012	11.5% grading to 5.5% in 2012

The following table presents the significant assumptions used to calculate NRG's benefit expense:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
Weighted-Average Assumptions	2006	2005	2006	2005
Discount rate	5.50%	5.75%	5.50%	5.75%
Expected return on plan assets	8.00%	8.00%	—	—
Rate of compensation increase	4.00-4.50%	4.00-4.50%	—	—
Health care trend rate	—	—	11.5% grading to 5.5% in 2012	9% grading to 5.5% in 2009

NRG uses December 31 of each respective year as the measurement date for the Company's pension and other postretirement benefit plans. The Company sets the discount rate assumptions on an annual basis for each of NRG's retirement related benefit plans at their respective measurement date. This rate is determined by NRG's Investment Committee based on information provided by the Company's actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of December 31, 2006 were based on the Hewitt Yield Curve, or HYC, which was designed by Hewitt Associates to provide a means for plan sponsors to value the liabilities of their postretirement benefit plans. The HYC is a hypothetical yield curve represented by a series of annualized individual discount rates. Each bond issue underlying the HYC is required to have a rating of Aa or better by Moody's Investor Service, Inc. or a rating of AA or better by Standard & Poor's. Prior to using the HYC rates, the discount rate assumptions for pension expense in 2006 and 2005 and the future pension obligations as of December 31, 2005 were based on investment yields available on AA rated long-term corporate bonds. The discount rates determined on the basis described above were 5.92 percent as of December 31, 2006 and 5.50 percent as of December 31, 2005.

NRG employs a total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The target allocation of plan assets is 60% to 80% invested in equity securities, with the remainder invested in fixed income securities. The Investment Committee reviews the asset mix periodically and as the plan assets increase in future years, the Investment Committee may examine other asset classes such as real estate or private equity. NRG employs a building block approach to determining the long-term rate of return for plan assets, with proper consideration given to diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed income are preserved, consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. equities, as well as among growth, value, small and large capitalization stocks.

NRG's pension plan assets weighted average allocation as of December 31, 2006 and 2005 were as follows:

	As of December 31,	
	2006	2005
US Equity	55%	56%
International Equity	17%	15%
US Fixed Income	28%	29%

NRG's expected future benefit payments are as follows:

	Pension Benefits	Other Postretirement Benefit	
	Benefit Payments	Benefit Payments	Medicare Prescription Drug Reimbursements
		(In millions)	
2007	$ 22	$ 1	$ —
2008	14	2	—
2009	16	2	—
2010	18	3	—
2011	19	3	—
2012-2016	$ 124	$ 21	$ 1

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total service and interest cost components	$ 1	$ (1)
Effect on postretirement benefit obligation	7	(6)

Defined Contribution Plans

NRG's employees have also been eligible to participate in defined contribution 401(K) plans. The Company's contributions to these plans were approximately $15 million, $5 million, and $4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Note 13 — Capital Structure

The following table reflects the changes in NRG's common stock issued and outstanding during 2005 and 2006:

	Authorized	Issued	Treasury	Outstanding
Balance as of December 31, 2004	500,000,000	100,041,935	(13,000,000)	87,041,935
Shares issued from LTIP during 2005	—	6,741	—	6,741
Accelerated Share Repurchase Program, August 2005	—	—	(6,346,788)	(6,346,788)
Balance as of December 31, 2005	500,000,000	100,048,676	(19,346,788)	80,701,888
Shares issued January 2006	—	20,855,057	—	20,855,057
Acquisition of Texas Genco LLC	—	16,059,504	19,346,788	35,406,292
Shares issued from LTIP during 2006	—	160,895	—	160,895
Capital Allocation Program — Phase I	—	—	(10,587,700)	(10,587,700)
Capital Allocation Program — Phase II	—	—	(4,212,881)	(4,212,881)
Balance as of December 31, 2006	500,000,000	137,124,132	(14,800,581)	122,323,551

Common Stock

NRG's authorized common stock consists of 500 million shares of NRG stock. Common stock issued as of December 31, 2006 and 2005 were 137,124,132 and 100,048,676, respectively, at a par value of $0.01 per share. Common stock issued and outstanding as of December 31, 2006 and 2005 were 122,323,551 and 80,701,888, respectively.

Stock issued to the Sellers pursuant to the Acquisition Agreement

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

Common Stock issued to the Public

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

Treasury Stock

As of December 31, 2006 and 2005, NRG had repurchased 14,800,581 and 19,346,788 shares, respectively, at a cost of approximately $732 million and $663 million, respectively, of the Company's common stock.

On October 13, 2006, NRG completed Phase I of NRG's Capital Allocation Program with the repurchase of 10,587,700 shares of the Company's common stock for approximately $500 million. At maturity, should NRG's stock price exceed a compound annual growth rate of 20% beyond a volume-weighted average share price determined at the time of repurchase, referred to as the Reference Price, NRG will pay to Credit Suisse excess of the market value of NRG's stock price over the Reference Price in either cash or stock. This difference will be recorded as an increase to the cost of the treasury shares repurchased.

On November 24, 2006, as part of Phase II of NRG's Capital Allocation Program, NRG repurchased 4,212,881 shares of NRG common stock from affiliates of the Blackstone Group at a price of $55.00 per share for a total of approximately $232 million. The Blackstone Group affiliates received the shares in a private transaction as part of the consideration that NRG paid for the acquisition of Texas Genco LLC. Following this repurchase, the four largest previous shareholders of Texas Genco LLC have concluded the sale of all of their NRG common stock received pursuant to the Acquisition. We expect to complete Phase II during the second half of 2007.

Preferred Stock

As of December 31, 2006, the Company had 10,000,000 shares of preferred stock authorized. As of December 31, 2006, the Company's preferred stock consisted of three series, the 5.75% Mandatory Convertible Preferred Stock, or 5.75 Preferred Stock, the 4% Convertible Perpetual Preferred Stock, or 4% Preferred Stock, and the 3.625% Convertible Perpetual Preferred Stock, which is treated as Redeemable Preferred Stock, or 3.625% Preferred Stock.

5.75% Preferred Stock

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

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

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

4% Preferred Stock

As of December 31, 2006 and 2005, 420,000 shares of the Company's 4% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs, of $406 million. Holders of the 4% Preferred Stock are entitled to receive, when declared by NRG's Board of Directors, cash dividends at the rate of 4% per annum, or $40.00 per share per year, payable quarterly in arrears commencing on March 15, 2005. The 4% Preferred Stock is convertible, at the option of the holder, at any time into shares of NRG's common stock at an initial conversion price of $40.00 per share. On or after December 20, 2009, NRG may redeem, subject to certain limitations, some or all of the 4% Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

Should NRG be subject to a fundamental change, as defined in the Certificate of Designation of the 4% Preferred Stock, each holder of shares of the 4% Preferred Stock has the right, subject to certain limitations, to require NRG to purchase any or all of the Company's shares of Preferred Stock at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends, including liquidated damages, if any, to the date of purchase. Final determination of a fundamental change must be approved by the Board of Directors. Each holder of the 4% Preferred Stock has one vote for each share of the 4% Preferred Stock held by the holder on all matters voted upon by the holders of NRG common stock, as well as voting rights specifically provided for in NRG's amended and restated certificate of incorporation or as otherwise, from time to time, required by law.

The 4% Preferred Stock is, with respect to dividend rights and rights upon liquidation, winding up or dissolution: junior to all of NRG's existing and future debt obligations; junior to each other class or series of NRG's capital stock other than (1) NRG's common stock and any other class or series of the Company's capital stock that provides that such class or series will rank junior to the 4% Preferred Stock, and (2) any other class or series of NRG's capital stock, the terms of which provide that such class or series will rank on a parity with the 4% Preferred Stock.

Redeemable Preferred Stock

3.625% Preferred Stock

On August 11, 2005, NRG issued 250,000 shares of 3.625% Preferred Stock, which is treated as Redeemable Preferred Stock, to Credit Suisse in a private placement. As of December 31, 2006, 250,000 shares of the 3.625% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs, of $247 million. The 3.625% Preferred Stock amount is located after the Liabilities but before the Stockholders' Equity section on the Balance Sheet as of December 31, 2005, due to the fact that the preferred shares can be redeemed in cash by the shareholder.

The 3.625% Preferred Stock has a liquidation preference of $1,000 per share. Holders of the 3.625% Preferred Stock are entitled to receive, out of legally available funds, cash dividends at the rate of 3.625% per annum, or $36.25 per share per year, payable in cash quarterly in arrears commencing on December 15, 2005. Each share of the 3.625% Preferred Stock is convertible during the 90-day period beginning August 11, 2015 at the option of NRG or the holder. Holders tendering the 3.625% Preferred Stock for conversion shall be entitled to receive, for each share of 3.625% Preferred Stock converted, $1,000 in cash and a number of shares of NRG common stock equal to the product of (a) the greater of (i) the difference between the average closing share price of NRG common stock on each of the 20 consecutive scheduled trading days starting on the date 30 exchange business days immediately prior to the conversion date, or the Market Price, and $59.085 and (ii) zero, times (b) 25.38715. The number of NRG common stock to be delivered under the conversion feature is limited to 8,000,000 shares. If upon conversion, the Market Price is less than $39.39, then the Holder will deliver to NRG cash or a number of shares of NRG common stock equal in value to the product of (i) $39.39 minus the Market Price, times (ii) 25.38715. NRG may elect to make a cash payment in lieu of delivering shares of NRG common stock in connection with such conversion, and NRG may elect to receive cash in lieu of shares of common stock, if any, from the Holder in connection with such conversion. If a fundamental change occurs, the holders will have the right to require NRG to repurchase all or a portion of the 3.625% Preferred Stock for a period of time after the fundamental change at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends. The 3.625% Preferred Stock is senior to all classes of common stock, on a parity with the Company's 4% Preferred Stock, and junior to all of the Company's existing and future debt obligations and all of NRG subsidiaries' existing and future liabilities and capital stock held by persons other than NRG or its subsidiaries.

Note 14 — Investments Accounted for by the Equity Method

NRG accounts for the company's significant investments using the equity method of accounting. NRG's carrying value of equity investments can be impacted by impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates, as well as other adjustments.

The following table summarizes NRG's significant equity method investments, which were in operation as of December 31, 2006:

Name	Geographic Area	Economic Interest
MIBRAG	Germany	50.0%
Saguaro Power Company, or Saguaro	USA	50.0%
Gladstone Power Station, or Gladstone	Australia	37.5%

Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method for the years ended December 31, 2006, 2005 and 2004 was as follows:

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Summarized Statements of Operations			
Operating revenues	$ 910	$ 1,300	$ 2,428
Costs and expenses	770	1,107	1,966
Net income	140	193	462
Summarized Balance Sheets			
Current assets	223	592	
Non-current assets	1,697	2,561	
Total assets	1,920	3,153	
Current liabilities	53	133	
Non-current liabilities	1,021	1,143	
Equity	846	1,877	
Total liabilities and equity	1,920	3,153	
NRG's share of equity and net income			
NRG's share of equity	344	810	
NRG's share of net income	$ 60	$ 104	$ 160

MIBRAG — NRG owns a 50% interest in MIBRAG. Located near Leipzig, Germany, MIBRAG owns and manages a coal mining operation, three lignite fueled power generation facilities and other related businesses. Approximately 40% of the power generated by MIBRAG is used to support its mining operations, with the remainder sold to a German utility company. A portion of the coal from MIBRAG's mining operation is used to fuel the power generation facilities, but a majority of the mined coal is sold primarily to two major customers, including Schkopau, an affiliate of NRG. A significant portion of MIBRAG's sales are made pursuant to long-term coal and energy supply contracts.

The following tables summarize financial information for MIBRAG, including interests owned by NRG and other parties for the periods shown below:

Results of Operations

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Operating revenues	$464	$432	$427
Operating income	76	72	61
Net income	59	52	43

Financial Position

	As of December 31,	
	2006	2005
	(In millions)	
Current assets	$ 90	$ 121
Other assets	1,012	1,134
Total assets	1,102	1,255
Current liabilities	23	22
Other liabilities	850	885
Equity	229	348
Total liabilities and equity	$1,102	$1,255

For the years ended December 31, 2006, 2005 and 2004, NRG's equity earnings from MIBRAG were approximately $30 million, $26, million and $21 million, respectively.

As discussed in Note 2, *Summary of Significant Accounting Policies*, the Company's MIBRAG equity investment was negatively affected by EITF 04-6. As of December 31, 2005, MIBRAG had an asset of approximately €157 million, or $185 million, representing capitalized stripping costs incurred during production. Following adoption of EITF 04-6 in the first quarter of 2006, NRG's investment in MIBRAG was reduced by 50% of the above mentioned asset, or approximately $93 million, with an offsetting charge to retained earnings.

Saguaro Power Company — NRG purchased a 50% interest in Saguaro in September 2001. Located in Henderson, near Las Vegas, Nevada, the Saguaro plant is a cogeneration plant with dual-fuel capability, natural gas and oil, and has contracted its electricity to Nevada Power through 2022, one steam host, referred to as Pioneer, whose contract expires in 2007, with a negotiated renewal, and a steam off taker, Ocean Spray, whose contract runs through 2015.

Saguaro Power Company, LP, the project company, procures fuel in the open market. NRG manages its share of any fuel price risk through NRG's commodity price risk strategy. At the end of 2005, NRG determined that it had a permanent decline in value of its 50% interest and recorded a write down of the Company's equity investment in Saguaro by approximately $27 million.

For the year ended December 31, 2006, NRG's equity earnings from Saguaro was a loss of approximately $1 million. NRG had no equity earnings in 2005 but recorded $5 million in equity earnings from Saguaro for the year ended December 31, 2004.

Gladstone — NRG owns a 37.5% interest in Gladstone, an unincorporated joint venture, or UJV, which operates a 1,613 megawatt coal-fueled power generation facility in Queensland, Australia. The power generation facility is managed by the joint venture participants and the facility is operated by NRG. Operating expenses incurred in connection with the operation of the facility are funded by each of the participants in proportion to their ownership interests. Coal is sourced from a mining operation owned and operated by certain joint venture partners and other investors under a long-term supply agreement. NRG and the joint venture participants receive a majority of their respective share of revenues directly from customers and are directly responsible and liable for project-related debt, all in proportion to the ownership interests in the UJV. Power generated by the facility is primarily sold to an adjacent aluminum smelter, with excess power sold on the national market.

For the years ended December 31, 2006, 2005 and 2004, NRG's equity earnings from Gladstone were approximately $25 million, $24 million and $18 million, respectively.

As discussed in Note 3, *Business Acquisitions and Dispositions*, on June 8, 2006, NRG announced the sale of the Company's 37.5% equity interest in the Gladstone power station, or Gladstone, and its associated 100% owned NRG Gladstone Operating Services to Transfield Services of Australia. The sale is pending until NRG satisfies certain conditions, particularly the securing of certain consents and waivers from the other owners of the project, or agrees to complete the sale on alternative terms.

Note 15 — Write Downs and Gains/(Losses) on Sales of Equity Method Investments

Investments accounted for by the equity method are reviewed for impairment in accordance with APB 18, which requires that a loss in value of an investment that is other than a temporary decline should be recognized. Gains or losses are recognized on completion of the sale. Write downs and gains/(losses) on sales of equity method investments recorded in other income/expense in the Company's consolidated statements of operations include the following:

	Year ended December 31,			
	2006	2005	2004	Segment(a)
	(In millions)			
Latin American Funds	$ 3	$ —	$ —	International
James River Power LLC	(6)	—	(7)	Corporate
Cadillac	11	—	—	Corporate
Saguaro	—	(27)	—	West
Rocky Road	—	(20)	—	Corporate
Kendall	—	4	—	Corporate
Enfield	—	12	—	International
Commonwealth Atlantic Limited Partnership	—	—	(5)	Corporate
NEO Corporation	—	—	(4)	Corporate
Loy Yang	—	—	(1)	International
Calpine Cogeneration	—	—	1	Corporate
Total write downs and gains/(losses) on sales of equity method investments	$ 8	$ (31)	$ (16)	

(a) Conforms to NRG's revised segment classification

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

James River — On May 15, 2006, NRG completed the sale of Capistrano Cogeneration Company, a subsidiary of NRG which owned a 50% interest in James River, to Cogentrix. The proceeds from the sale were approximately $8 million. As a result of the sale, NRG recorded a pre-tax loss of approximately $6 million. In 2004, NRG recorded an impairment charge of approximately $7 million to write down the value of the Company's investment in James River to its fair value.

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

Saguaro — During the fourth quarter of 2005, due to the expiration of the partnership's long-term gas supply contract and higher market prices paid for natural gas, NRG determined that a decline in the value of the Company's 50% investment in Saguaro was considered to be permanent and recorded a write down of the Company's investment of approximately $27 million.

Rocky Road — In December 2005, NRG entered into a purchase and sale agreement with Dynegy, Inc., whereby NRG agreed to sell to Dynegy the Company's 50% ownership interest in Rocky Road Power LLC for $45 million in cash. As a result of the purchase and sale agreement with Dynegy, NRG recorded an impairment charge of approximately $20 million to write down the value of the Company's 50% interest in Rocky Road to the investment's fair value of $45 million.

Kendall — In December 2004, NRG sold its interest in Kendall to LS Power Associates, L.P., or LS Power. Under the terms of the December 2004 agreement, NRG retained the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount, or the Call Option. Therefore, the transaction was treated as a partial sale for accounting purposes. On August 8, 2005, NRG executed an agreement with LS Power to sell the Call Option for $5 million. A pre-tax gain of $4 million was recognized in the third quarter of 2005.

Enfield — On April 1, 2005, NRG completed the sale of the Company's 25% interest in Enfield to Infrastructure Alliance Limited. Net cash proceeds received from the sale were approximately $65 million and a pre-tax gain of approximately $12 million was recorded in 2005.

Commonwealth Atlantic Limited Partnership, or CALP — In June 2004, NRG executed an agreement to sell the Company's 50% interest in CALP. During the third quarter of 2004, NRG recorded an impairment charge of approximately $4 million to write down the value of the Company's investment in CALP to its fair value. The sale closed in November 2004, resulting in net cash proceeds of $15 million. Total impairment charges as a result of the sale were approximately $5 million.

NEO Corporation — On September 30, 2004, NRG completed the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. The sale also included four wholly-owned NEO subsidiaries; see Note 4, *Discontinued Operations.* NRG received cash proceeds of approximately $6 million for both the investments and subsidiaries, resulting in a loss of approximately $4 million attributable to the equity investment entities sold.

Calpine Cogeneration — In January 2004, NRG executed an agreement to sell the Company's 20% interest in Calpine Cogeneration Corporation to Calpine Power Company. The transaction closed in March 2004 and resulted in net cash proceeds of $3 million.

Note 16 — Earnings Per Share

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

Dilutive effect for equity compensation — The outstanding 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.

Dilutive effect for other equity instruments — NRG's outstanding 4% 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 Company's 3.625% Preferred Stock includes a conversion feature that, if dilutive, is calculated using the if-converted method as well.

The reconciliation of NRG's basic earnings per common share to diluted earnings per share for the years ended December 31, 2006, 2005 and 2004 is shown in the following table:

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except per share data)		
Basic earnings per share			
Numerator:			
Income from continuing operations	$ 555	$ 72	$ 155
Deduct preferred stock dividends	(52)	(20)	(1)
Income available to common stockholders from continuing operations	503	52	154
Discontinued operations, net of tax	66	12	31
Net income available to common stockholders	$ 569	$ 64	$ 185
Denominator:			
Weighted average number of common shares outstanding	129.0	84.6	99.6
Basic earnings per share:			
Income from continuing operations	$ 3.90	$0.61	$1.55
Discontinued operations, net of tax	0.51	0.15	0.31
Net income	$ 4.41	$0.76	$ 1.86
Diluted earnings per share			
Numerator:			
Income available to common stockholders from continuing operations	503	52	154
Add preferred stock dividends for dilutive preferred stock	43	—	1
Adjusted income from continuing operations	546	52	155
Discontinued operations, net of tax	66	12	31
Net income available to common stockholders	$ 612	$ 64	$ 186

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except per share data)		
Denominator:			
Weighted average number of common shares outstanding	129.0	84.6	99.6
Incremental shares attributable to the issuance of non-qualifying stock options (treasury stock method)	0.4	0.2	—
Incremental shares attributable to the issuance of non-vested restricted stock units (treasury stock method)	0.9	0.4	0.4
Incremental shares attributable to the assumed conversion of deferred stock units (treasury stock method)	0.1	0.1	0.1
Incremental shares attributable to the assumed conversion of the 4% preferred stock (if converted method)	10.5	—	0.3
Incremental shares attributable to the assumed conversion of the 5.75% preferred stock (if converted method)	9.4	—	—
Total dilutive shares	150.3	85.3	100.4
Diluted earnings per share:			
Income from continuing operations	$ 3.63	$0.61	$ 1.54
Discontinued operations, net of tax	0.44	0.14	0.31
Net income	$ 4.07	$0.75	$ 1.85

Elements of Equity Compensation

Non-Qualified Stock Options — For the years ended December 31, 2006, 2005 and 2004, options to purchase 137,284, 132,500 and 962,751 shares of common stock at an average exercise price of $54.52, $38.80 and $23.15 per share, respectively, were not included in the computation of diluted earnings per share because the exercise price of the options was greater than the average market price of the common stock for the full year, and therefore the effect would have been anti-dilutive.

Performance Units — For the years ended December 31, 2006 and 2005, all of the Company's performance units, 205,332 and 44,900, respectively, were not included in the computation of diluted earnings per share because the average market price of NRG's common stock was less than the target price of the outstanding performance units, and therefore the effect would have been anti-dilutive. There were no outstanding Performance Units as of December 31, 2004.

Preferred Stock

5.75% Preferred Stock — For the year ended December 31, 2006, on a weighted average basis, 9,357,211 shares of common stock associated with the 5.75% Preferred Stock were included in the diluted earnings per share computation; these securities were issued on February 2, 2006.

4% Preferred Stock — For the year ended December 31, 2006, 10,500,000 shares of common stock associated with the 4% Preferred Stock were included in the diluted earnings per share computation. For the year ended December 31, 2005, the outstanding 4% Preferred Stock, which is convertible into 10,500,000 shares of common stock was not included in the diluted earnings per share computation because the effect would have been anti-dilutive. However, for the year ended December 31, 2004, on a weighted average basis, 343,324 shares of common stock associated with the 4% Preferred Stock were included in the diluted earnings per share computation.

3.625% Preferred Stock — The 3.625% Preferred Stocks' conversion feature allows for additional cash or common shares to be issued if the average stock price for a 20-day period prior to redemption exceeds $59.08 — the market price trigger. The Company did not include this conversion feature in the calculation of diluted earnings per share, as the market price trigger was higher than the average market price of NRG's common stock during the year and period ended December 31, 2006 and 2005, and therefore the effect would have been anti-dilutive.

Note 17 — Segment Reporting

As NRG continues to improve the Company's position in deregulated generation markets and to dispose of non-strategic assets, senior management has reorganized the composition of NRG's operating segments for the purpose of making operational decisions and assessing performance.

The major changes included the acquisition of Texas Genco LLC and the sale of multiple non-strategic assets. This has resulted in the creation of a new Texas region wholesale power generation segment, and the collapse of the Company's Other North America region.

The new segment structure reflects NRG's core areas of operation which are primarily the geographic regions of the Company's wholesale power generation, thermal and chilled water business, and corporate activities. Within NRG's wholesale power generation operations, there are distinct components with separate operating results and management structures for the following regions: Texas, Northeast, South Central, West and International. All prior periods have been restated to reflect the current change in the Company's segment structure.

On January 1, 2005, management changed the allocation criteria of corporate general and administrative expenses to the segments. Prior to 2005, corporate general and administrative expenses were allocated based on an analysis of man hours spent on work for each segment. As of January 1, 2005, corporate general and administrative expenses are allocated based on the forecasted revenue to be generated by each segment.

The following table summarizes customers from whom NRG derived more than 10% of the Company's consolidated revenues for the years ended December 31, 2006, 2005 and 2004. The revenues associated with these customers were all recorded within the Company's Northeast region results:

Year Ended December 31,	2006	2005	2004
Customer A	10.0%	39.7%	32.0%
Customer B	—	16.3	10.2
Total %	10.0%	56.0%	42.2%

	Year Ended December 31, 2006								
	Wholesale Power Generation								
	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
					(In millions)				
Operating revenues	$ 3,088	$ 1,543	$ 570	$ 146	$ 173	$ 152	$ 12	$ (61)	$ 5,623
Operating expenses	1,794	993	397	135	125	121	30	(3)	3,592
Depreciation and amortization	413	89	68	3	3	12	5	—	593
Operating income/(loss)	881	461	105	8	45	19	(23)	(58)	1,438
Equity in earnings of unconsolidated affiliates	—	—	—	1	57	—	2	—	60
Write downs and losses on sales of equity method investments	—	—	—	—	3	—	5	—	8
Other income, net	9	6	—	1	11	1	152	(20)	160
Refinancing expenses	—	—	—	—	—	—	(187)	—	(187)
Interest expense	(138)	(63)	(57)	—	(10)	(7)	(344)	20	(599)
Income/(loss) from continuing operations before income taxes	752	404	48	10	106	13	(395)	(58)	880
Income tax expense/(benefit)	23	—	—	(2)	26	—	278	—	325
Income/(loss) from continuing operations	729	404	48	12	80	13	(673)	(58)	555
Income on discontinued operations, net of income taxes	—	—	—	—	49	—	17	—	66
Net income/(loss)	$ 729	$ 404	$ 48	$ 12	$ 129	$ 13	$ (656)	$ (58)	$ 621
Balance Sheet									
Equity investments in affiliates	—	1	—	29	312	—	2	—	344
Capital expenditures	125	49	11	7	5	12	12	—	221
Goodwill	1,782	—	—	—	—	—	7	—	1,789
Total assets	$12,980	$ 1,583	$ 1,029	$ 176	$ 1,293	$ 251	$ 12,611	$ (10,488)	$19,435

If the Company continued using the full year 2004 allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the year ended December 31, 2006 would have been as follows:

	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Net income/(loss) as reported	$ 729	$ 404	$ 48	$ 12	$ 129	$ 13	$ (656)	$ (58)	$ 621
Increase/(decrease) in net income	50	5	5	3	6	3	(72)	—	—
Adjusted net income/(loss)	$ 779	$ 409	$ 53	$ 15	$ 135	$ 16	$ (728)	$ (58)	$ 621

	Year Ended December 31, 2005							
	Wholesale Power Generation							
	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
	(In millions)							
Operating revenues	$ 1,554	$ 560	$ 4	$ 165	$ 150	$ 6	$ (9)	$ 2,430
Operating expenses	1,262	485	9	121	118	35	(11)	2,019
Depreciation and amortization	74	67	1	4	11	5	—	162
Corporate relocation charges	—	—	—	—	—	6	—	6
Impairment charges	—	—	—	—	—	6	—	6
Operating income/(loss)	218	8	(6)	40	21	(46)	2	237
Equity in earnings of unconsolidated affiliates	—	—	22	69	—	13	—	104
Write downs and losses on sales of equity method investments	—	—	(27)	12	—	(16)	—	(31)
Other income, net	4	—	1	21	2	51	(21)	58
Refinancing expenses	—	—	—	—	—	(65)	—	(65)
Interest expense	—	(27)	—	(8)	(8)	(162)	21	(184)
Income/(loss) from continuing operations before income taxes	222	(19)	(10)	134	15	(225)	2	119
Income tax expense	—	—	—	26	4	17	—	47
Income/(loss) from continuing operations	222	(19)	(10)	108	11	(242)	2	72
Income/(loss) on discontinued operations, net of income taxes	—	—	—	(2)	4	10	—	12
Net income/(loss)	$ 222	$ (19)	$ (10)	$ 106	$ 15	$ (232)	$ 2	$ 84
Balance Sheet								
Equity investments in affiliates	1	—	188	357	—	56	—	602
Capital expenditures	51	26	—	17	6	6	—	106
Total assets	$ 1,865	$ 1,200	$ 203	$ 1,548	$ 264	$ 4,983	$ (2,597)	$ 7,466

If the Company continued using the full year 2004 allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the year ended December 31, 2005 would have been as follows:

Net income/(loss) as reported	$ 222	$ (19)	$ (10)	$ 106	$ 15	$ (232)	$ 2	$ 84
Increase/(decrease) in net income	24	14	—	10	5	(53)	—	—
Adjusted net income/(loss)	$ 246	$ (5)	$ (10)	$ 116	$ 20	$ (285)	$ 2	$ 84

	Year Ended December 31, 2004							
	Wholesale Power Generation							
	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
	(In millions)							
Operating revenues	$ 1,251	$ 434	$ 7	$ 159	$ 131	$ 129	$ (7)	$ 2,104
Operating expenses	860	300	14	118	108	99	(12)	1,487
Depreciation and amortization	73	69	1	3	11	22	—	179
Corporate relocation charges	—	—	—	—	—	16	—	16
Reorganization items	—	1	—	—	—	(14)	—	(13)
Impairment charges	—	3	—	—	—	42	—	45
Operating income/(loss)	318	61	(8)	38	12	(36)	5	390
Equity in earnings of unconsolidated affiliates	—	—	74	69	—	17	—	160
Write downs and losses on sales of equity method investments	—	—	—	(1)	(4)	(11)	—	(16)
Other income, net	4	1	—	7	1	30	(21)	22
Refinancing expenses	—	—	—	—	—	(72)	—	(72)
Interest expense	(1)	(29)	—	(11)	(9)	(226)	21	(255)
Income/(loss) from continuing operations before income taxes	321	33	66	102	—	(298)	5	229
Income tax expense	—	1	2	17	—	54	—	74
Income/(loss) from continuing operations	321	32	64	85	—	(352)	5	155
Income on discontinued operations, net of income taxes	—	—	—	9	3	19	—	31
Net income/(loss)	$ 321	$ 32	$ 64	$ 94	$ 3	$ (333)	$ 5	$ 186

Note 18 — Income Taxes

The income tax provision from continuing operations for the years ended December 31, 2006, 2005 and 2004 consisted of the following amounts:

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Current			
U.S.	$ (27)	$ 19	$ —
Foreign	21	15	15
	(6)	34	15
Deferred			
U.S.	326	2	57
Foreign	5	11	2
	331	13	59
Total income tax	$ 325	$ 47	$ 74
Effective tax rate	36.9%	39.5%	32.3%

The following represents the domestic and foreign components of income/(loss) from continuing operations before income tax expense for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
U.S.	$767	$ (11)	$129
Foreign	113	130	100
Total	$ 880	$119	$229

A reconciliation of the U.S. federal statutory rate of 35% to NRG's effective rate from continuing operations for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except percentages)		
Income from continuing operations before income taxes	$ 880	$ 119	$229
Tax at 35%	308	42	80
State taxes, net of federal benefit	34	(1)	6
Foreign operations	(23)	(16)	(13)
Section 965 taxable dividend	—	5	—
Subpart F taxable income	11	19	—
Valuation allowance, including change in state effective rate	(10)	22	—
Change in state effective tax rate	21	(22)	—
Claimant Reserve settlements	(28)	—	—
Permanent differences, reserves, other	12	(2)	1
Income tax expense	$ 325	$ 47	$ 74
Effective income tax rate	36.9%	39.5%	32.3%

The effective income tax rate for the year ended December 31, 2006 differs from the U.S. statutory rate of 35% primarily due to a basis difference relating to disbursements from the disputed claims reserve, changes in state effective income tax rate, and earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

For the year ended December 31, 2006, we decreased the estimated state effective income tax rate to 7% from the prior year state income tax rate of 9%. This decrease was due to the acquisition of Texas Genco LLC, which operates in the state of Texas where there is no state income tax as of December 31, 2006. A decrease to the net deferred tax asset balance of approximately $24 million, of which $21 million is derived from continuing operations and $3 million is from discontinued operations, has been recorded for this change. In addition, a reduction of $22 million, of which $19 million is generated from continuing operations and $3 million is from discontinued operations, reflected in our domestic valuation allowance, was recorded due to a change in our estimated state effective income tax rate during 2006. Beginning 2007, our state effective tax rate will increase, as the state of Texas has implemented a 1% margin tax for transactions beginning on January 1, 2007.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The temporary differences, which gave rise to the Company's deferred tax assets and liabilities as of December 31, 2006 and 2005, consisted of the following:

	As of December 31, 2006	As of December 31, 2005
	(In millions)	
Deferred tax liabilities:		
Discount/premium on notes	$ 25	$ 23
Emissions allowances	83	113
Difference between book and tax basis of property	1,552	191
Derivative asset, net	216	—
Goodwill	51	—
Total deferred tax liabilities	1,927	327
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	133	56
Derivative liability, net	—	148
Differences between book and tax basis of contracts	890	146
Non-depreciable property	21	197
Intangibles amortization (excluding goodwill)	145	12
Stock options	16	10
Claimants reserve	8	80
U.S. net operating loss carry forwards	27	38
U.S. capital loss carryforwards	485	238
Foreign net operating loss carryforwards	75	70
Investments in projects	6	63
Other	11	3
Total deferred tax assets	1,817	1,061
Valuation allowance	(581)	(836)
Net deferred tax assets	1,236	225
Net deferred tax liability	$ 691	$ 102

The following table summarizes NRG's net deferred tax position as of December 31, 2006 and 2005:

	As of December 31, 2006	As of December 31, 2005
	(In millions)	
Current deferred tax liability	$ 164	$ —
Non-current deferred tax asset	(27)	(26)
Non-current deferred tax liability	554	128
Net deferred tax liability	$691	$ 102

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Taxes payable

During 2006, we recorded a current tax payable of approximately $17 million that represents a tax liability due to a domestic state tax of approximately $7 million, as well as foreign taxes payable of approximately $10 million. In addition, NRG has a tax receivable of $15 million, which relates to a taxable loss generated by Texas Genco Holdings Inc., that will be carried back to a prior year's return for a tax refund.

Deferred tax assets, liabilities and valuation allowance

For the year ended December 31, 2006, NRG's net deferred tax asset decreased by $844 million (before valuation allowance), resulting in a domestic net deferred tax liability of $110. This decrease was primarily due to the acquisition of Texas Genco LLC that resulted in a $349 million net deferred tax liability and the current income from continuing operations before income tax that resulted in a reduction in deferred tax assets of $331 million.

Acquisition of NRG Texas — NRG established a deferred tax asset of $2.868 billion and $3.217 billion of deferred tax liabilities in purchase accounting as a result of the acquisition of NRG Texas.

NOL carryforwards — As of December 31, 2006, the Company had domestic NOL carryforwards available for federal and state income tax purposes of $72 million that will expire in 2026. NRG also has cumulative foreign NOL carryforwards of $270 million, of which $73 million will expire in 2015 and of which $197 million does not have an expiration date.

Valuation allowance — Due to an assessment of positive and negative evidence, including projected capital gains and available tax planning strategies, NRG believes that it is more likely than not that a benefit will not be realized on $581 million of domestic tax assets. This amount reflects deferred tax assets for domestic capital loss carryforwards of $506 million expiring through 2011 and foreign operating losses of $75 million. A valuation allowance for these deferred tax assets remains, resulting in a net deferred tax liability of $691 million.

As a result of the reduction in NRG's net deferred tax assets, the Company's valuation allowance and other deferred tax items were reduced. In accordance with SOP 90-7, these movements resulted in the reduction of intangibles by $241 million, an increase in Additional Paid in Capital of $17 million and reduced tax expense by $22 million (of which $3 million was reflected in discontinued operations).

APB Opinion 23

To the extent that NRG does not provide deferred income taxes for unremitted earnings, it is management's intent to permanently reinvest those earnings overseas in accordance with APB Opinion No. 23, *Accounting for Income Taxes-Special Areas*, or APB 23.

Repatriation of foreign funds pursuant to the American Jobs Creation Act of 2004

Pursuant to the Jobs Act, during 2005, NRG elected to deduct 85% of certain eligible dividends received from non-U.S. subsidiaries from its taxable income before the end of 2005 as those dividends were reinvested in the U.S. for eligible purposes. NRG repatriated approximately $298 million of accumulated foreign earnings. Only a portion of this amount represents the cumulative earnings and profits, which resulted in approximately $6 million of tax expense. The remaining amounts transferred are considered a return of capital.

Tax Holidays

During 2005, the "Amazon Development Agency" granted an income tax holiday to our subsidiary ITISA pertaining to the local tax liability resulting from ITISA's operating income for Brazilian tax purposes, applicable retroactively to January 1, 2005. The tax holiday program reduced the effective income tax rate to 15.25% from a statutory income tax rate of 34%, resulting in a decrease in tax expense of approximately $3 million in 2006. This tax holiday will expire on December 31, 2013.

Note 19 — Stock-Based Compensation

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

Long-Term Incentive Plan, or LTIP

As of December 31, 2006, a total of 8,000,000 shares of NRG common stock were authorized for issuance under the LTIP, subject to adjustments in the event of a reorganization, recapitalization, stock split, reverse stock split, stock dividend, and a combination of shares, merger or similar change in NRG's structure or outstanding shares of common stock. It is NRG's policy to issue treasury shares upon exercise of a LTIP award. If there are no treasury shares available, shares of common stock will be issued. There were 4,301,489 shares of common stock remaining available for grants under NRG's LTIP as of December 31, 2006.

Non-Qualified Stock Options, or NQSO's

NQSO's granted under the LTIP typically have a three-year graded vesting schedule beginning on the grant date and become exercisable at the end of the requisite service period. As provided for by SFAS 123(R), for share options with graded vesting issued after January 1, 2006, NRG recognizes compensation costs on a straight-line basis over the requisite service period for the entire award. The maximum contractual term is ten years for approximately 600,000 of NRG's outstanding NQSO's, and six years for the remaining 1.1 million NQSO's. The aggregate intrinsic value for stock options outstanding as of December 31, 2006 was approximately $35.5 million. The aggregate intrinsic value for stock options exercisable as of December 31, 2006 was approximately $26.4 million. The weighted average remaining contractual term for stock options outstanding as of December 31, 2006 was approximately six years. The weighted average remaining contractual term for stock options exercisable as of December 31, 2006 was approximately seven years. During the year ended December 31, 2006, cash received from the exercise of NQSO's and the intrinsic value of exercised NQSO's was $1.1 million and $1.3 million, respectively. There were no NQSO's exercised as of December 2005 and 2004.

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The fair value of stock option grants is estimated on the date of grant using the Black-Scholes option-pricing model. The following table shows the change in the Company's outstanding NQSO balance during the past three years:

	Shares	Weighted Average Exercise Price	Weighted Average Grant-Date Fair Value Per Share
	(In whole, except weighted average data)		
Outstanding as of December 31, 2003	632,751	$ 24.03	$ 13.17
Granted	330,000	21.46	10.20
Outstanding as of December 31, 2004	962,751	23.15	12.15
Outstanding as of December 31, 2004	962,751	23.15	12.15
Granted	134,000	38.80	13.23
Forfeited	(1,500)	38.80	13.23
Outstanding as of December 31, 2005	1,095,251	25.04	12.29
Outstanding as of December 31, 2005	1,095,251	25.04	12.29
Granted	814,185	48.60	14.51
Forfeited	(154,068)	38.43	12.53
Exercised	(49,832)	21.48	9.77
Outstanding at December 31, 2006	1,705,536	35.18	13.40
Exercisable at December 31, 2006	831,911	$ 24.22	$ 12.64

The fair value of the Company's NQSO's issued for the year ended December 31, 2006, 2005, and 2004 was based on the following assumptions:

	Year ended December 31, 2006	2005	2004
Expected Volatility	27.95%-29.64%	29.75%	51.05%
Weighted-average volatility	28.38%	29.75%	51.05%
Expected dividends	—	—	—
Expected term (in years)	4-6	5	5
Risk free rate	4.30%-5.05%	4.16%	2.86%-3.83%

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

Restricted Stock Units, or RSU's

Typically, RSU's granted under the Company's LTIP fully vest three years from the date of issuance. Compensation expense is based on the fair value of the RSU's which is based on the closing price of NRG common stock on the date of grant, multiplied by the number of RSU's granted. Such compensation expense, net of forfeitures, is amortized over the requisite service period. In determining NRG's forfeiture rate, two separate forfeiture rates that best represent the employment termination behavior related to issued RSU's were used: 8% for senior management; and 25% for all other employees. The forfeiture rates were based on an analysis of NRG's historical forfeitures, employment turnover, and expected future behavior. The aggregate intrinsic values for non-vested RSU's on December 31, 2006, 2005 and 2004 were approximately $64 million, $60 million, and $32 million, respectively.

The following table shows the change in NRG's outstanding RSU balance during the past three years:

	Shares	Weighted Average Grant-Date Fair Value per share
	(In whole except weighted average data)	
Non-vested as of December 31, 2003	173,394	$ 24.03
Granted	750,100	20.94
Forfeited	(40,500)	20.02
Exercised	(2,000)	19.90
Non-vested as of December 31, 2004	880,994	21.59
Granted	473,850	38.70
Forfeited	(66,250)	24.05
Exercised	(2,650)	20.97
Non-vested as of December 31, 2005	1,285,944	27.78
Granted	212,643	47.73
Forfeited	(165,950)	30.69
Exercised	(194,044)	25.55
Non-vested at December 31, 2006	1,138,593	$ 31.48

Deferred Stock Units, or DSU's

DSU's granted under the Company's LTIP are fully vested at the date of issuance. Compensation expense recorded is the fair value of the DSU based on the closing price of NRG common stock on the date of grant. For DSU's, compensation expense is fully recognized in the period of grant. The aggregate intrinsic values for DSU's outstanding as of December 31, 2006, 2005 and 2004 were approximately $7.9 million, $5.8 million and $2.3 million, respectively. The aggregate intrinsic values for DSU's converted to common stock for the years ended December 31, 2006, 2005 and 2004 were approximately $0.4 million, $0.3 million and $1.3 million, respectively. None of the DSU's issued was either canceled or had expired as of December 31, 2006.

The following table shows the change in NRG's outstanding DSU balance for the years ended December 2006, 2005 and 2004:

	Shares	Weighted Average Grant-Date Fair Value Per Share
	(In whole, except weighted average data)	
Outstanding as of December 31, 2003	—	—
Granted	100,961	$ 20.36
Conversions	(40,680)	20.49
Outstanding as of December 31, 2004	60,281	20.31
Granted	68,201	37.54
Conversions	(6,298)	28.20
Outstanding as of December 31, 2005	122,184	29.21
Granted	25,830	49.22
Conversions	(7,594)	38.75
Outstanding at December 31, 2006	140,420	$ 32.38

Performance Units, or PU's

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

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

Grant Date	Vesting Period	Outstanding Shares	Target Price	Maximum Price
August 1, 2005	3	36,300	$ 54.50	$ 63.75
January 3, 2006	3	83,800	67.37	79.49
February 3, 2006	3	52,632	66.41	77.67
May 31, 2006	5	4,400	69.90	81.74
May 31, 2006	3	4,400	69.90	81.74
August 1, 2006	3	1,400	68.27	79.83
November 13, 2006	3	10,200	76.48	89.45
December 18, 2006	3	12,200	$ 81.28	$ 95.05

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The following table shows the change in the Company's outstanding PU balance for the years ended December 31, 2006 and 2005:

	Outstanding Shares	Weighted Average Grant-Date Fair Value Per Share
	(In whole, except weighted average data)	
Non-vested as of December 31, 2004	—	—
Granted	45,900	$ 29.87
Exercised	—	—
Forfeited	(1,000)	29.87
Non-vested as of December 31, 2005	44,900	29.87
Granted	202,532	35.23
Exercised	—	—
Forfeited	(42,100)	33.12
Non-vested at December 31, 2006	205,332	$ 34.49

The fair value of PU's is estimated on the date of grant using a Monte Carlo simulation model. Volatility is calculated based on a blended average of NRG and NRG's industry peers' two-year historical stock price volatility data. The aggregate intrinsic value for PU's outstanding as of December 31, 2006 and 2005 was approximately $11.5 million and $2.1 million, respectively.

A forfeiture rate of 8% was calculated for PU's based on an analysis of NRG's historical forfeitures, employment turnover, and expected future behavior. Significant assumptions used in the fair value model for the years ended December 31, 2006 and 2005 with respect to the Company's PU's are summarized below. There were no PU's outstanding for the year ended December 31, 2004.

	Year Ended December 31,	
	2006	2005
Expected volatility	27.95%-29.64%	29.75%
Weighted — average volatility	28.38%	29.75%
Expected dividends	—	—
Expected term (in years)	3-5	3
Risk free rate	4.30%-5.04%	4.09%

Supplemental Information

The following table summarizes NRG's total compensation expense recognized in accordance with SFAS 123(R) for the years ended December 31, 2006, 2005 and 2004 for each of the four types of awards issued under the Company's LTIP, as well as total non-vested compensation costs not yet recognized as of December 31, 2006. Minimum tax withholdings of $4 million paid by the Company during 2006 are reflected as a reduction to additional paid in capital on the Company's statement of financial position, and are reflected as operating activities on the Company's statement of cash flow.

	Compensation Expense			Total Non-vested Compensation Cost Not yet Recognized	Weighted Average Life Remaining
	Year ended December 31			As of December 31	
Award	2006	2005	2004	2006	2006
	(In millions, except weighted average data)				
NQSO's	$ 5	$ 4	$ 7	$ 8	1.1
RSU's	10	8	5	16	1.1
DSU's	1	3	2	—	—
PU's	2	—	—	5	2.1
Total	18	15	14	29	
Tax benefit recognized	$ 7	$ 6	$ 6		

Note 20 — Related Party Transactions

Operating Agreements

NRG has entered into operation and maintenance agreements, or O&M agreements, with certain Company equity investments including Saguaro and Gladstone. Fees for services under these contracts primarily include recovery of NRG's costs of operating the plant as approved in the annual budget, as well as a base monthly fee. In addition, NRG renders technical consulting services to MIBRAG under a consulting agreement. NRG has also entered into long-term coal purchase agreements with MIBRAG to supply coal to Schkopau.

These fees and expenses are included in the Company's operating revenues and operating costs in the consolidated statements of operations and consisted of the following:

Related Party Transactions with Equity Investments

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Revenues from Related Parties Included in Operating Revenues			
WCP[(a)]			
O&M fees	$ 1	$ 6	$ 4
AMA fees	—	2	3
Saguaro			
O&M fees	—	—	—
Gladstone			
O&M fees	2	3	2
MIBRAG			
Consulting fees	4	4	3
Total	$ 7	$ 15	$ 12
Expenses from Related Parties Included in Cost of Operations			
MIBRAG			
Cost of purchased coal	$ 43	$ 41	$ 39

(a) *For the period January 1, 2006 to March 31, 2006*

Note 21 — Commitments and Contingencies

Operating Lease Commitments

With the acquisition of Texas Genco LLC, NRG's operating lease commitments increased significantly. This increase was primarily due to the anticipated commencement of leases for 2,695 railcars over the next two years. As of December 31, 2006, approximately 1,813 of the railcars had been delivered and were under lease for future commitments of approximately $188 million.

NRG leases certain Company facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2023. Certain operating lease agreements over their lease term include provisions such as scheduled rent increases, leasehold incentives, and rent concessions. The Company recognizes the effects of these scheduled rent increases, leasehold incentives, and rent concessions on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed. Rental expense under operating leases was approximately $27 million, $9 million and $11 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2006 are as follows:

	(In millions)
2007	$ 39
2008	36
2009	34
2010	32
2011	31
Thereafter	255
Total	$ 427

In September 2005, Texas Genco LLC entered into a contract to purchase 2,695 aluminum railcars from FreightCar America, Inc., formerly Johnstown America Corporation, to be used for the transportation of low sulfur coal from Wyoming to its coal burning generating plants. On February 2, 2006, NRG closed on the acquisition of Texas Genco LLC. On March 10, 2006, NRG entered into a twenty-year operating lease agreement with Metropolitan Life Insurance Company, or MetLife, for the lease of 945 railcars. Delivery of the railcars from FreightCar America under the MetLife lease agreement commenced in March 2006 and was completed by October 2006. NRG has assigned certain of its rights and obligations for the 945 railcars under the purchase agreement with FreightCar America to MetLife. Accordingly, the railcars that NRG leases from MetLife under the arrangement described above, were purchased by MetLife from FreightCar America in lieu of the Company's purchase of those railcars. On August 29, 2006, NRG entered into a similar seventeen-year operating lease agreement with General Electric Capital Corporation, or GE Capital, for the lease of the remaining 1,750 railcars. Delivery of the railcars from FreightCar America under the GE Capital arrangement commenced in October 2006 and is expected to be completed in early 2007. NRG has likewise assigned certain of its rights and obligations for the 1,750 railcars under the purchase agreement with FreightCar America to GE Capital. Accordingly, the railcars that NRG leases from MetLife under the arrangement described above were likewise purchased by GE Capital from FreightCar America in lieu of the Company's purchase of those railcars.

Coal, Gas and Transportation Commitments

NRG has entered into long-term contractual arrangements to procure fuel and transportation services for the Company's generation assets and as of December 31, 2006, the Company's commitments under such outstanding agreements are estimated as follows:

	(In millions)
2007	$ 1,614
2008	514
2009	420
2010	277
2011	228
Thereafter	593
Total(a)	$ 3,646

(a) Includes only those coal transportation and gas commitments for 2007 as no other nominations were made as of December 31, 2006.

International Commitments

Two of the Company's wholly-owned, indirect subsidiaries are severally responsible for the prorate payments of principal, interest and related costs incurred in connection with the financing of NRG's equity investment in the unincorporated joint venture Gladstone Power Station. At December 31, 2006, the Company was obligated for the loan of AUD 66 million (approximately US $52 million) in principal. This loan is scheduled to be fully repaid on March 31, 2009.

NRG FinCo Resolution

In May 2001, NRG's wholly-owned subsidiary, NRG Financial Company I LLC, or NRG FinCo, entered into a $2 billion revolving credit facility. The facility was established to finance the acquisition, development and construction of certain power generating plants located in the United States, as well as to finance the acquisition of turbines for such facilities. The facility provided for borrowings of base rate loans and Eurocurrency loans and was secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects, and by guarantees from each subsidiary or affiliate. The NRG FinCo secured revolver was initially scheduled to mature on May 8, 2006; however, due to defaults hereunder by NRG FinCo and applicable guarantors, the lenders accelerated all outstanding obligations on November 6, 2002. As of the Company's emergence from bankruptcy, $1.1 billion was outstanding under the facility, and there was approximately $58 million of accrued but unpaid interest and commitment fees. Of this total amount, $842 million was allowed in unsecured claims under the NRG plan of reorganization, and was settled at the time of the Company's emergence from bankruptcy. The remaining balance is to be satisfied when the NRG FinCo lenders exercise their perfected security interests in the Nelson, Audrain and Pike projects. During 2004, NRG sold the assets of LSP Nelson Energy LLC for approximately $20 million and certain assets of the Company's Pike project for $17 million. The proceeds from these sales were paid to the lenders of NRG FinCo. On March 29, 2006, NRG's subsidiary NRG Audrain Generating LLC sold the Audrain project to AmerenUE, a subsidiary of Ameren Corporation, for $115 million, subject to customary purchase price adjustments, plus AmerenUE's assumption of $240 million of non-recourse capital lease obligations and 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 NRG FinCo lenders. During 2006, NRG sold the remaining Pike equipment and the proceeds from these sales along with the remaining Pike cash paid to the lenders of NRG FinCo. As a result of the sale of the Nelson, Audrain and Pike assets and the payment of the proceeds from these sales to the lenders of NRG FinCo, the NRG FinCo lenders have released the sold Audrain, Pike and Nelson projects from their respective obligations under the NRG FinCo secured revolver. On December 29, 2006, NRG dissolved LSP-Pike Energy, LLC and, accordingly, $13 million of outstanding liabilities of LSP-Pike Energy, LLC are no longer reflected on the Company's consolidated balance sheet, and were recorded to other income in the Company's consolidated statement of operations.

Contingencies

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

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

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these ordinary course matters will not materially adversely effect NRG's consolidated financial position, results of operations, or cash flows.

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

California Electricity and Related Litigation

NRG, WCP, WCP's four operating subsidiaries, Dynegy, Inc., and numerous other unrelated parties are the subject of numerous lawsuits that arose based on events that occurred in the California power market in 2000 and 2001. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market gaming activities. Certain of these lawsuits originally commenced in 2000 and 2001, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Southern District of California. The consolidated cases moved between state and federal court several times. On May 5, 2005, the case was remanded to California state court, and under a scheduling order, defendants filed their objections to the pleadings. On July 22, 2005, based upon the filed rate doctrine and federal preemption, the court dismissed NRG Energy, Inc. without prejudice, leaving only subsidiaries of WCP remaining in the case. On October 3, 2005, the court sustained defendants' demurrer, dismissing the case against all remaining defendants. On December 2, 2005, the plaintiffs filed their notice of appeal from the dismissal with the California State Court of Appeals — Fourth District and on February 26, 2007, the court affirmed the lower court's judgment of dismissal. Other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers that name WCP and/or subsidiaries of WCP, in addition to numerous other defendants. These complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California's antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees, and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several of these proceedings.

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

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

In August 2006, Dynegy entered into an agreement to settle class action claims by California natural gas resellers and cogenerators. These claims are pending in Nevada federal district court in *"In Re Western States Wholesale Natural Gas Antitrust Litigation"*. WCP and its subsidiaries are named defendants and Dynegy's settlement would include full releases for these entities. The settlement is expected to be submitted to the court for approval in 2007. Neither WCP, it subsidiaries, nor NRG paid any defense costs or settlement funds, as Dynegy owed and provided a complete defense and indemnification.

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

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

California Department of Water Resources

On December 19, 2006, the U.S. Court of Appeals for the Ninth Circuit reversed FERC's prior determinations regarding the enforceability of certain wholesale power contracts and remanded the case to FERC for further proceedings consistent with the decision. One of these contracts was the wholesale power contract between the California Department of Water Resources, or CDWR, and subsidiaries of WCP. This case originated with a February 2002 complaint filed at FERC by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, FERC rejected this complaint, denied rehearing, and the case was appealed to the Ninth Circuit where oral argument was held on December 8, 2004. The Court decided that in FERC's review of the contracts at issue, FERC could not rely on the Mobile-Sierra standard presumption of just and reasonable rates, where such contracts were not reviewed by FERC with full knowledge of the then existing market conditions. Because an extension of time will be filed shortly, WCP and the other defendants will have until April 18, 2007, to seek review by the U.S. Supreme Court, or they can instead wait for the case to be remanded back to FERC. If review before the U.S. Supreme Court is sought, the Court will decide in 2007 whether it will accept the appeal. At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG's financial position, statement of operations, and statement of cash flows. As part of the 2006 acquisition of Dynegy's 50% ownership interest in WCP, WCP and NRG assumed responsibility for any risk of loss arising from this case, unless any such loss was deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally between WCP and Dynegy.

Connecticut Congestion Charges

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

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 the disputes in the action. At FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo's petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. On April 22, 2005, FERC denied NiMo's motion for rehearing. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on June 23, 2006, denied the appeal finding that NYISO's station service program that permits generators to self supply their station power needs by netting consumption against production in a month is lawful. On October 23, 2006, the D.C. Circuit denied NiMo's petition for rehearing and on January 22, 2007, NiMo sought review before the U.S. Supreme Court. NRG believes it is adequately reserved.

On December 14, 1999, NRG acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an order finding that, at times when NRG is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration. In July and August 2006, the parties submitted their respective statements of the case to the three member arbitration panel. A discovery and briefing schedule was issued and a hearing is set for September 2007. NRG believes it is adequately reserved.

ITISA

NRG's Brazilian project company, ITISA, the owner of a 155 MW hydro project in Brazil, is in arbitration with the former Engineering, Procurement and Construction, or EPC, contractor for the project, Inepar Industria e Construcoes, or Inepar. The dispute was commenced in arbitration by ITISA in September 2002 and pertains to certain matters arising under the EPC contract between the parties. ITISA sought Real 140 million and asserted that Inepar breached the contract. Inepar sought Real 39 million and alleged that ITISA breached the contract. On September 2, 2005, the arbitration panel ruled in favor of ITISA, awarding it Real 139 million and Inepar Real 4.7 million. Due to interest accrued from the commencement of the arbitration to the award date, ITISA's award was increased to approximately Real 227 million (approximately $106 million as of December 31, 2006). Itiquira has commenced the lengthy process in Brazil to execute on the arbitral award. NRG is unable to predict the outcome of this execution process. On December 21, 2005, Inepar's request for clarifications was denied. Due to the uncertainty of the ongoing collection process, NRG is accounting for receipt of any amounts as a gain contingency.

CFTC Trading Litigation

On July 1, 2004, the Commodities Futures Trading Commission, or CFTC, filed a civil complaint against NRG in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking a permanent injunction against future violations of the Commodity Exchange Act. On March 15, 2005, NRG's motion to dismiss was granted by the federal district court. On appeal, the U.S. Court of Appeals for the Eighth Circuit, on August 2, 2006, reversed the district court's dismissal of the CFTC's action. The parties have agreed to a settlement in which NRG agreed to give the CFTC a $2 million allowed class 5 claim in NRG's bankruptcy proceeding. The settlement agreement was approved by the Court on February 13, 2007.

Disputed Claims Reserve

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

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company's Chapter 11 plan, totaling $25 million in cash and 2,541,000 shares of common stock. As of January 24, 2007, the reserve held approximately $9.9 million in cash and approximately 691,700 shares of common stock. NRG believes the cash and stock together represent sufficient funds to satisfy all remaining disputed claims.

Bourbonnais Agreements

On January 31, 2006, NRG finalized a stipulation and settlement agreement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001. The stipulation fixes the amount and provides for the allowance of the equipment manufacturer's proof of claim previously filed during NRG's bankruptcy proceeding. The settlement agreement provides for a $6 million payment by NRG to the equipment manufacturer, and the release of all claims NRG Bourbonnais and NRG have for the return of payments made under the 1999 and 2001 turbine purchase agreements. Under the settlement agreement, NRG received certain equipment valued at $55 million, as well as a one-year option to purchase new-build equipment for a fixed price. During the first quarter 2006, NRG recorded approximately $67 million of other income associated with the settlement due to a 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 22 — Regulatory Matters

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

Texas Region

As of December 31, 2006, the decommissioning trusts for the decontamination and decommissioning of STP had a market value of $352 million. The unamortized portion of the retirement obligation asset was $262 million. The decommission liability was $324 million, and the reserve to fund the decommissioning from the trust assets and payments to or from ratepayers was $289 million. In accordance with SFAS 71, and due to the fact that NRG does not have any economic exposure for these decommissioning responsibilities, changes in the related assets and liabilities are not reflected in the statement of operations. As such, the total carrying value of all assets and liabilities associated with the decommissioning and the trusts will always be equal.

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

Northeast Region

New England — On December 28, 2006, the Attorneys General of the State of Connecticut and Commonwealth of Massachusetts filed an appeal of the FERC orders accepting the settlement of the New England capacity market design with the U.S. Court of Appeals for the D.C. Circuit. The settlement, filed March 7, 2006, by a broad group of New England market participants, provides for interim capacity transition payments for all generators in New England for the period starting December 1, 2006 through May 31, 2010, and the establishment of a FCM commencing May 31, 2010. On June 16, 2006, FERC issued an order accepting the settlement, which was reaffirmed on rehearing by order dated October 31, 2006. Interim capacity transition payments provided for under the FCM settlement commenced December 1, 2006, as scheduled. A successful appeal by the Attorneys General could disturb the settlement and create a refund obligation of interim capacity transition payments.

On January 18, 2007, FERC announced that it had reached a resolution with NRG regarding the informal investigation arising from NRG's self-reporting to FERC and ISO-NE that on January 25, 2006, Devon Unit 12 was unable to respond to a dispatch instruction, and that inaccurate information was provided to ISO-NE. On December 22, 2006, NRG entered into a Stipulation and Consent Agreement with FERC pursuant to which NRG agreed to a pay a civil penalty of $0.5 million, as well as to conduct additional audits during 2007 of its remaining Connecticut RMR units.

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

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

West Region

On December 1, 2006, NRG filed to extend the existing RMR agreements for NRG's Cabrillo Power I, LLC (Encina) and Cabrillo Power II, LLC (San Diego Jets) for 2007, and is seeking to continue the existing rate effective January 1, 2007. On January 24, 2007, FERC accepted the Cabrillo Power I filing. On January 30, 2007, FERC accepted the Cabrillo II filing, subject to refund, in response to protests filed by the CPUC and CAISO, and established settlement procedures.

Note 23 — Environmental Matters

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

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that approximately $1.28 billion of capital expenditures will be incurred during the period 2007 through 2012 in order to keep NRG's facilities in compliance with environmental laws, primarily related to installation of particulate, SO_2, NOx, and mercury controls to comply with Clean Air Interstate Rule, or CAIR, and the Clean Air Mercury Rule, or CAMR, as well as installation of Best Technology Available under the Phase II 316(b) Rule. NRG updates its estimates for environmental capital expenditures annually. These plans, including installed equipment and timing as well as cost can be expected to change over time, in some cases materially. These plans are based on current regulatory requirements and best engineering practices. Changes to regulations or market conditions could result in changes to installed equipment timing or associated costs.

Other Environmental Matters

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

Texas Region

The lignite used to fuel the Texas region's Limestone facility is obtained from a surface mine adjacent to the facility under an amended long-term contract with Texas Westmoreland Coal Co., or TWCC, entered into in August 1999. TWCC is responsible for performing ongoing reclamation activities at the mine until all lignite reserves have been produced. When production is completed at the mine, NRG will be responsible for final mine reclamation obligations. The Railroad Commission of Texas has imposed a bond obligation of approximately $70 million on TWCC for the reclamation of this lignite mine. Final reclamation activity is expected to commence in 2015. Pursuant to the contract with TWCC, an affiliate of CenterPoint Energy, Inc. has guaranteed $50 million of this obligation until 2010. The remaining sum of approximately $20 million has been bonded by the mine operator, TWCC. Under the terms of the agreement, NRG is required to post a corporate guarantee in the amount of $50 million of TWCC's reclamation bond when CenterPoint's obligation lapses. As of December 31, 2006, NRG has accrued approximately $20 million related to the mine reclamation obligation.

Northeast Region

In January 2006, NRG Indian River Operations, Inc. received a letter of informal notification from the Delaware Department of Natural Resources and Environmental Control, or DNREC, stating that it may be a potentially responsible party with respect to a historic captive landfill. NRG is working with DNREC through the Voluntary Clean-up Program to investigate the site. The Company is unable to predict the exact financial impact at this time, but NRG believes the cost to remediate will not be material to the Company's consolidated financial position or results of operations.

In November 2006, the Delaware Department of Natural Resources and Environmental Control, or DNREC, promulgated Regulation No. 1146, or Reg 1146, Electric Generating Unit Multi-Pollutant Regulation and Section 111(d) of the State Plan for the Control of Mercury Emissions from Coal-Fired Electric Steam Generating Units. These regulations govern the control of SO_2, NOx, and mercury emissions from electric generating units. NRG's current plan to install controls at the Company's Indian River facility, while on an accelerated basis, is unable to meet certain deadlines for SO_2 and NOx controls in Phase 1, taking into account the time required, as a practical matter, to design, install, and commission the necessary equipment. NRG and the owners of all other subject facilities in the state filed a challenge to Reg 1146 with the Environmental Appeals Board on December 6, 2006. In addition, NRG also filed a protective appeal with the Delaware Superior Court on December 29, 2006. NRG is unable to predict the outcome of the proceedings at this time, but failure to obtain relief may result in a material impact on the Company's results of operations.

South Central Region

On January 27, 2004, NRG's Louisiana Generating, LLC and the Company's Big Cajun II plant received a request under Section 114 of the Clean Air Act, or CAA, from USEPA seeking information primarily related to physical changes made at the Big Cajun II plant,and subsequently received a notice of violation, or NOV, on February 15, 2005, alleging that NRG's predecessors had undertaken projects that triggered requirements under the PSD program, including the installation of emission controls. NRG submitted multiple responses commencing February 27, 2004 and ending on October 20, 2004. On May 9, 2006, these entities received from the Department of Justice, or DOJ, a notice of deficiency related to their responses, to which NRG responded on May 22, 2006. A document review was conducted at NRG's Louisiana Generating, LLC offices by the DOJ during the week of August 14, 2006. On December 8, 2006, the USEPA issued a supplemental NOV updating the original February 15, 2005 NOV. Discussions with the USEPA are ongoing. NRG cannot predict with certainty the outcome of this matter.

Note 24 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Interest paid, net of amount capitalized	$450	$257	$295
Income taxes paid	18	21	34
Non-cash investing and financing activities:			
Reduction to fixed assets due to liquidated damages	—	—	15
Addition to fixed assets due to asset retirement obligations	15	4	—
Addition to treasury stock for the maximum purchase price adjustment	—	8	—

Note 25 — Guarantees

NRG and its subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of the Company's business activities. Examples of these contracts include asset purchase and sale agreements, commodity sale and purchase agreements, joint venture agreements, operations and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties. These contracts generally indemnify the counter-party for tax, environmental liability, litigation, and other matters, as well as breaches of representations, warranties, and covenants set forth in the agreements. In many cases, the Company's maximum potential liability cannot be estimated, since some of the underlying agreements contain no limits on potential liability. In accordance with FIN 45, NRG has estimated that the current fair value for issuing these guarantees was approximately $13 million as of December 31, 2006, and the liability in this amount is included in the Company's non-current liabilities.

The following table summarizes NRG's estimated guarantees, indemnity, and other contingent liability obligations by maturity:

	By Remaining Maturity at December 31, 2006					
	Under 1 year	1-3 years	3-5 years	Over 5 years	Total	2005 Total
	(In millions)					
Guarantees						
Synthetic letters of credit	$523	$ 444	$ —	$ —	$ 967	$ —
Funded standby letters of credit	—	—	—	—	—	312
Unfunded letters of credit and surety bonds	97	56	—	—	153	4
Asset sales guarantee obligations	—	13	110	21	144	123
Commercial sales arrangements	133	51	—	420	604	91
Other guarantees	1	—	—	28	29	91
Total guarantees	$754	$ 564	$ 110	$ 469	$1,897	$621

Letters of credit and surety bonds — As of December 31, 2006, NRG and its consolidated subsidiaries were contingently obligated for a total of approximately $1.1 billion under letters of credit. Most of these letters of credit are issued in support of the Company's obligations to perform under commodity agreements, financing or other arrangements. A majority of these letters of credit expire within one year of issuance, and it is typical for the Company to renew them on similar terms.

Asset sale guarantees — NRG is typically requested to provide certain assurances to the counter-parties of the Company's asset sale agreements. Such assurances may take the form of a guarantee issued by the Company on behalf of a directly or indirectly held majority-owned subsidiary which include certain indemnifications to a third party, usually the buyer, as described below. Due to the inter-company nature of such arrangements, NRG is essentially guaranteeing its own performance, and the nature of the guarantee being provided. It is not the Company's policy to recognize the value of such an obligation in its consolidated financial statements. Most of these guarantees provide an explicit cap on the Company's maximum liability, as well as an expiration period, exclusive of breach of representations and warranties.

On August 30, 2006, with the completion of the sale of Flinders, NRG guaranteed the payment and performance of the Flinders subsidiaries' obligations under the sale and purchase agreement. Maximum liability of NRG is limited to the sale price of AU$317 million (approximately $242 million). In addition, with the completion of the sale, existing guarantees and indemnities of NRG related to Flinders were released.

On March 31, 2006, NRG purchased the remaining 50% interest in WCP from Dynegy. In conjunction with the purchase, NRG agreed to indemnify Dynegy, subject to certain caps and limitations, for breach of representations, warranties, covenants, and losses incurred under the CDWR litigation and certain California electricity-related litigation. For further information about the litigation, see Note 21, *Commitments and Contingencies.*

Commercial sales arrangements — In connection with the purchase and sale of fuel, emission allowances and power generation products to and from third parties with respect to the operation of some of NRG's generation facilities in the U.S., the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments.

Other guarantees — NRG has issued guarantees of obligations that its subsidiaries may incur as a provision for environmental site remediation, payment of debt obligations, rail car leases, and performance under operating and maintenance agreements. In 2006, NRG executed a guarantee to the benefit of two counterparties under the Company's railcar lease described in Note 21, *Commitments and Contingencies*. These guarantees cover payment and performance obligations of the Company's wholly-owned subsidiary, NRG Texas LP. The Company does not believe that it will be required to perform under this indemnity.

The material indemnities, within the scope of FIN 45, are as follows:

Asset purchases and divestitures — The purchase and sale agreements, which govern NRG's asset or share investments and divestitures, customarily contain indemnifications of the transaction to third parties. The contracts indemnify the parties for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party, or as a result of a change in tax laws. These obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or estimate at the time of the transaction. In several cases, the contract limits the liability of the indemnifier. For those indemnities in which liability is capped, the minimum exposures range from $1 million to $249 million. NRG has no reason to believe that the Company currently has any material liability relating to such routine indemnification obligations.

Other indemnities — Other indemnifications NRG has provided cover operational, tax, litigation and breaches of representations, warranties and covenants. NRG has also indemnified, on a routine basis in the ordinary course of business, consultants or other vendors who have provided services to the Company. NRG's maximum potential exposure under these indemnifications can range from a specified dollar amount to an indeterminate amount, depending on the nature of the transaction. Total maximum potential exposure under these indemnifications is not estimable due to uncertainty as to whether claims will be made or how they will be resolved. NRG does not have any reason to believe that the Company will be required to make any material payments under these indemnity provisions.

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

Note 26 — Jointly Owned Plants

Certain NRG subsidiaries own undivided interests in certain jointly-owned plants, described below. These plants are maintained and operated pursuant to their joint ownership participation and operating agreements. NRG is responsible for its subsidiaries share of operating costs and direct expense and includes its proportionate share of the facilities and related revenues and expenses in these jointly-owned plants in the appropriate balance sheet and income statement captions.

The following table summarizes NRG's proportionate ownership interest in the Company's jointly-owned facilities as of December 31, 2006:

As of December 31, 2006	Ownership Interest	Property, Plant & Equipment	Accumulated Depreciation	Construction in Progress
		(In millions unless otherwise stated)		
South Texas Project, Bay City, TX	44.00%	$ 2,877	$ 160	$ 10
Big Cajun II Unit 3, New Roads, LA	58.00	168	30	6
Keystone, Shelocta, PA	3.70	59	9	2
Conemaugh, New Florence, PA	3.72	71	11	—

Note 28 — Unaudited Quarterly Financial Data

Summarized quarterly unaudited financial data is as follows:

	Quarter Ended 2006			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 1,144	$ 2,000	$ 1,404	$ 1,075
Operating income	100	718	411	209
Income from continuing operations	(33)	373	200	15
Income on discontinued operations net of income taxes	3	49	3	11
Net income/(loss)	$ (30)	$ 422	$ 203	$ 26
Weighted average number of common shares outstanding — basic	125	136	137	117
Income/(loss) from continuing operations per weighted average common share — basic	$ (0.37)	$ 2.65	$ 1.36	$ 0.04
Income from discontinued operations per weighted average common share — basic	0.02	0.35	0.02	0.09
Net income/(loss) per weighted average common share — basic	$ (0.35)	$ 3.00	$ 1.38	$ 0.13
Weighted average number of common shares outstanding — diluted	125	159	159	119
Income/(loss) from continuing operations per weighted average common share — diluted	$ (0.37)	$ 2.34	$ 1.24	$ 0.04
Income from discontinued operations per weighted average common share — diluted	0.02	0.31	0.02	0.09
Net income/(loss) per weighted average common share — diluted	$ (0.35)	$ 2.65	$ 1.26	$ 0.13

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Quarter Ended 2005			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 707	$ 687	$ 502	$ 534
Operating income	161	(8)	38	46
Income/(loss) from continuing operations	76	(37)	18	15
Income/(loss) on discontinued operations net of income taxes	(12)	10	6	8
Net income/(loss)	$ 64	$ (27)	$ 24	$ 23
Weighted average number of common shares outstanding — basic	81	84	87	87
Income/(loss) from continuing operations per weighted average common share — basic	$ 0.87	$ (0.51)	$ 0.16	$ 0.13
Income/(loss) from discontinued operations per weighted average common share — basic	(0.15)	0.12	0.07	0.08
Net income/(loss) per weighted average common share — basic	$ 0.72	$ (0.39)	$ 0.23	$ 0.21
Weighted average number of common shares outstanding — diluted	92	84	88	88
Income/(loss) from continuing operations per weighted average common share — diluted	$ 0.81	$ (0.51)	$ 0.15	$ 0.13
Income/(loss) from discontinued operations per weighted average common share — diluted	(0.13)	0.12	0.07	0.08
Net income/(loss) per weighted average common share — diluted	$ 0.68	$ (0.39)	$ 0.22	$ 0.21

For 2006 and 2005, NRG reclassified the financial results of Resource Recovery, Flinders, and Audrain as discontinued operations. Accordingly, 2006 and 2005 quarterly results have been restated to report the results as discontinued. Quarterly financial data for 2006 includes the results of the Company's Texas region beginning February 2, 2006 and WCP beginning April 1, 2006.

Note 29 — Condensed Consolidating Financial Information

As of December 31, 2006, the Company had $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016 and $1.1 billion Senior Notes due 2017 outstanding. These notes are guaranteed by certain of NRG's current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

Each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 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
Chickahominy River Energy Corp.
NRG California Peaker Operations LLC
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Generation Holdings, Inc.
NRG Huntley Operations Inc.

Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power LLC
El Segundo Power II LLC
GCP Funding Company, LLC
Hanover Energy Company
Hoffman Summit Wind Project, LLC
Huntley IGCC LLC
Huntley Power LLC
Indian River IGCC LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Lake Erie Properties Inc.
Long Beach Generation LLC
Louisiana Generating LLC
Middletown Power LLC
Montville IGCC 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 Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services, Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG Texas LLC
NRG Texas LP
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Padoma Wind Power, LLC
Saguaro Power LLC
San Juan Mesa Wind Project II, LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services, LLC
Texas Genco Services, LP
Vienna Operations Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

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

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

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations(a)	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 5,282	$ 341	$ —	$ —	$ 5,623
Operating Costs and Expenses					
Cost of operations	3,040	234	2	—	3,276
Depreciation and amortization	562	26	5	—	593
General, administrative and development	115	17	184	—	316
Total operating costs and expenses	3,717	277	191	—	4,185
Operating Income/(Loss)	1,565	64	(191)	—	1,438
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	134	—	996	(1,130)	—
Equity in earnings of unconsolidated affiliates	2	58	—	—	60
Write downs and losses on sales of equity method investments	(5)	13	—	—	8
Other income, net	20	119	41	(20)	160
Refinancing expenses	—	—	(187)	—	(187)
Interest expense	(232)	(65)	(322)	20	(599)
Total other income/(expense)	(81)	125	528	(1,130)	(558)
Income From Continuing Operations Before Income Taxes	1,484	189	337	(1,130)	880
Income tax expense	549	45	(269)	—	325
Income From Continuing Operations	935	144	606	(1,130)	555
Income from discontinued operations, net of income tax expense/(benefit)	—	51	15	—	66
Net Income	$ 935	$ 195	$ 621	$ (1,130)	$ 621

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy Inc.	Eliminations(a)	Consolidated Balance
			(In millions)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 20	$ 432	$ 343	$ —	$ 795
Restricted cash	1	43	—	—	44
Accounts receivable-trade, net	332	40	—	—	372
Inventory	408	13	—	—	421
Deferred income taxes	—	—	—	—	—
Derivative instruments valuation	1,230	—	—	—	1,230
Collateral on deposit in support of energy risk management activities	27	—	—	—	27
Prepayments and other current assets	173	32	736	(747)	194
Current assets — discontinued operations	—	—	—	—	—
Total current assets	2,191	560	1,079	(747)	3,083
Net Property, Plant and Equipment	11,178	403	19	—	11,600
Other Assets					
Investment in subsidiaries	730	—	9,163	(9,893)	—
Equity investments in affiliates	31	313	—	—	344
Notes receivable, less current portion	1,015	114	5,503	(6,518)	114
Capital lease, less current portion, net	—	365	—	—	365
Goodwill	1,789	—	—	—	1,789
Intangible assets, net	977	4	—	—	981
Intangible assets held-for-sale	78	—	1	—	79
Nuclear decommissioning trust fund	352	—	—	—	352
Derivative instruments valuation	424	—	15	—	439
Deferred income taxes	27	—	—	—	27
Other non-current assets	24	56	182	—	262
Total other assets	5,447	852	14,864	(16,411)	4,752
Total Assets	$ 18,816	$ 1,815	$ 15,962	$ (17,158)	$ 19,435
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 460	$ 101	$ 37	$ (468)	$ 130
Accounts payable — trade	(682)	287	727	—	332
Derivative instruments valuation	964	—	—	—	964
Deferred income taxes	23	7	134	—	164
Accrued expenses and other current liabilities	509	53	160	(280)	442
Total current liabilities	1,274	448	1,058	(748)	2,032
Other Liabilities					
Long-term debt and capital leases	5,504	869	8,791	(6,517)	8,647
Nuclear decommissioning reserve	289	—	—	—	289
Nuclear decommissioning trust liability	324	—	—	—	324
Deferred income taxes	494	(104)	164	—	554
Derivative instruments valuation	325	6	20	—	351
Non-current out-of-market contracts	897	—	—	—	897
Other non-current liabilities	385	26	24	—	435
Non-current liabilities — discontinued operations	—	—	—	—	—
Total non-current liabilities	8,218	797	8,999	(6,517)	11,497
Total liabilities	9,492	1,245	10,057	(7,265)	13,529
Minority interest	—	1	—	—	1
3.625% Preferred Stock	—	—	247	—	247
Stockholders' Equity	9,324	569	5,658	(9,893)	5,658
Total Liabilities and Stockholders' Equity	$ 18,816	$ 1,815	$ 15,962	$ (17,158)	$ 19,435

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations(a)	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 935	$ 195	$ 621	$ (1,130)	$ 621
Adjustments to reconcile net income to net cash provided/(used) by operating activities					
Distributions in excess/(less than) equity in earnings of unconsolidated affiliates	(136)	(31)	(996)	1,130	(33)
Depreciation and amortization of nuclear fuel	609	35	10	—	654
Amortization and write-of of deferred financing costs and debt discount/premiums	—	6	73	—	79
Amortization of intangibles and out-of-market contracts	(487)	(3)	—	—	(490)
Amortization of unearned equity compensation	—	—	14	—	14
Write down and gains on sale of equity method investments	5	(13)	—	—	(8)
Loss on sale of equipment	10	—	—	—	10
Restructuring and impairment charges	—	—	—	—	—
Changes in derivatives	(151)	2	—	—	(149)
Changes in deferred income taxes	474	19	(166)	—	327
Gain on legal settlement	—	(67)	—	—	(67)
Gain on sale of discontinued operations	—	(71)	(5)	—	(76)
Gain on sale of emission allowances	(64)	—	—	—	(64)
Change in nuclear decommissioning trust liability	12	—	—	—	12
Changes in collateral deposits supporting energy risk management activities	454	—	—	—	454
Settlement of out-of-market power contracts	(1,073)	—	—	—	(1,073)
Cash provided by changes in other working capital, net of acquisition and disposition affects	(554)	213	538	—	197
Net Cash Provided by Operating Activities	34	285	89	—	408
Cash Flows from Investing Activities					
I/C loans to subsidiaries	(939)	—	(4,106)	5,045	—
Acquisition of Texas Genco LLC, WCP and Padoma, net of cash acquired	—	—	(4,333)	—	(4,333)
Capital expenditures	(195)	(21)	(5)	—	(221)
Decrease/(Increase) in restricted cash, net	2	4	—	—	6
Decrease/(Increase) in notes receivable	—	27	—	—	27
Purchases of emission allowances	(135)	—	—	—	(135)
Proceeds from sale of emission allowances	146	—	—	—	146
Investments in nuclear decommissioning trust fund securities	(227)	—	—	—	(227)
Proceeds from sales of nuclear decommissioning trust fund securities	214	—	—	—	214
Proceeds from sale of equipment	—	—	—	—	—
Proceeds from sale of investments	53	33	—	—	86
Proceeds from sale of discontinued operations	—	239	22	—	261
Net Cash Provided/(Used) by Investing Activities	(1,081)	282	(8,422)	5,045	(4,176)
Cash Flows from Financing Activities					
Payment of dividends to preferred stockholders	—	—	(50)	—	(50)
Payment of financing element of acquired derivatives	(296)	—	—	—	(296)
Payment for treasury stock	—	(500)	(232)	—	(732)
Funded letter of credit	—	—	350	—	350
Proceeds from Intercompany loans	4,106	—	939	(5,045)	—
Proceeds from issuance of common stock, net	—	—	986	—	986
Proceeds from issuance of preferred shares, net	—	—	486	—	486
Proceeds from issuance of long-term debt	—	333	8,286	—	8,619
Payment of deferred debt issuance costs	—	—	(199)	—	(199)
Payments of short and long-term debt	(2,736)	(62)	(2,313)	—	(5,111)
Net Cash Provided/(Used) by Financing Activities	1,074	(229)	8,253	(5,045)	4,053
Change in Cash from Discontinued Operations	—	12	1	—	13
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	4	—	—	4
Net Increase in Cash and Cash Equivalents	27	354	(79)	—	302
Cash and Cash Equivalents at Beginning of Period	(7)	78	422	—	493
Cash and Cash Equivalents at End of Period	$ 20	$ 432	$ 343	$ —	$ 795

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
Year Ended December 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations(a)	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 2,095	$ 340	$ —	$ (5)	$ 2,430
Operating Costs and Expenses					
Cost of operations	1,600	243	—	(5)	1,838
Depreciation and amortization	133	24	5	—	162
General, administrative and development	39	19	123	—	181
Impairment charges	6	—	—	—	6
Corporate relocation charges	—	—	6	—	6
Total operating costs and expenses	1,778	286	134	(5)	2,193
Operating Income/(Loss)	317	54	(134)	—	237
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	101	—	274	(375)	—
Equity in earnings of unconsolidated affiliates	35	69	—	—	104
Write downs and gains/(losses) on sales of equity method investments	(47)	16	—	—	(31)
Other income, net	16	50	13	(21)	58
Refinancing expense	—	1	(66)	—	(65)
Interest expense	(1)	(63)	(141)	21	(184)
Total other income	104	73	80	(375)	(118)
Income/(Loss) From Continuing Operations Before Income Taxes	421	127	(54)	(375)	119
Income tax expense/(benefit)	155	22	(130)	—	47
Income From Continuing Operations	266	105	76	(375)	72
Income from discontinued operations, net of income tax expense	5	(1)	8	—	12
Net Income	$ 271	$ 104	$ 84	$ (375)	$ 84

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
			(In millions)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ (7)	$ 78	$ 422	$ —	$ 493
Restricted cash	3	46	—	—	49
Accounts receivable-trade, net	214	250	(215)	—	249
Inventory	232	8	—	—	240
Deferred income taxes	6	(1)	(5)	—	—
Derivative instruments valuation	385	—	2	—	387
Collateral on deposit in support of energy risk management activities	438	—	—	—	438
Prepayments and other current assets	63	41	551	(468)	187
Current assets held for sale	8	—	35	—	43
Current assets — discontinued operations	—	98	12	—	110
Total current assets	1,342	520	802	(468)	2,196
Net Property, Plant and Equipment	2,176	414	19	—	2,609
Other Assets					
Investment in subsidiaries	787	—	1,774	(2,561)	—
Equity investments in affiliates	243	359	—	—	602
Notes receivable, less current portion — affiliate, net	76	457	1,397	(1,473)	457
Intangible assets, net	238	19	—	—	257
Derivative instruments valuation	18	—	—	—	18
Funded letter of credit	—	—	350	—	350
Deferred income taxes	—	26	—	—	26
Other non-current assets	22	19	83	—	124
Non-current assets — discontinued operations	—	814	13	—	827
Total other assets	1,384	1,694	3,617	(4,034)	2,661
Total Assets	$ 4,902	$ 2,628	$ 4,438	$ (4,502)	$ 7,466
LIABILITIES AND STOCK HOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 459	$ 90	$ 14	$ (468)	$ 95
Accounts payable, trade	158	67	16	—	241
Derivative instruments valuation	678	1	—	—	679
Other bankruptcy settlement	—	3	—	—	3
Other current liabilities	60	41	68	—	169
Current liabilities — discontinued operations	—	164	6	—	170
Total current liabilities	1,355	366	104	(468)	1,357
Other Liabilities					
Long-term debt and capital leases	1,397	620	1,866	(1,473)	2,410
Deferred income taxes	37	142	(51)	—	128
Derivative instruments valuation	25	11	20	—	56
Non-current out-of-market contracts	298	—	—	—	298
Other non-current liabilities	126	23	21	—	170
Non-current liabilities — discontinued operations	—	568	1	—	569
Total non-current liabilities	1,883	1,364	1,857	(1,473)	3,631
Total liabilities	3,238	1,730	1,961	(1,941)	4,988
Minority interest	—	1	—	—	1
3.625% Preferred Stock	—	—	246	—	246
Stockholders' Equity	1,664	897	2,231	(2,561)	2,231
Total Liabilities and Stockholders' Equity	$ 4,902	$ 2,628	$ 4,438	$ (4,502)	$ 7,466

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations(a)	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 271	$ 104	$ 84	$ (375)	$ 84
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distributions in excess/(less than) equity in earnings of unconsolidated affiliates	(64)	(45)	453	(352)	(8)
Depreciation and amortization of nuclear fuel	133	52	10	—	195
Amortization and write-of of deferred financing costs and debt discount/premiums	—	(4)	18	—	14
Amortization of intangibles and out-of-market contracts	(2)	19	—	—	17
Amortization of unearned equity compensation	3	1	8	—	12
Write down and (gains)/losses on sale of equity method investments	47	(16)	—	—	31
Loss on sale of equipment	4	—	—	—	4
Impairment charges	6	—	—	—	6
Changes in derivatives	150	(10)	3	—	143
Changes in deferred income taxes	71	13	(82)	—	2
Gain on legal settlement	—	(14)	—	—	(14)
Gain on sale of discontinued operations	(6)	—	—	—	(6)
Changes in collateral deposits supporting energy risk management activities	(405)	—	—	—	(405)
Cash provided by changes in other working capital, net of acquisition and disposition affects	(421)	10	404	—	(7)
Net Cash Provided/(Used) by Operating Activities	(213)	110	898	(727)	68
Cash Flows from Investing Activities					
Return of capital from subsidiaries	—	—	1,398	(1,398)	—
Intercompany loans to subsidiaries	—	—	(2,181)	2,181	—
Proceeds from intercompany loans with parents and subsidiaries	327	—	325	(652)	—
Capital expenditures	(78)	(22)	(6)	—	(106)
Decrease/(increase) in restricted cash, net	1	44	—	—	45
Decrease/(increase) in notes receivable	5	102	—	—	107
Deferred acquisition costs	—	—	(5)	—	(5)
Proceeds from sale of investments	9	70	—	—	79
Proceeds on sale of discontinued operations	36	—	—	—	36
Return of capital from equity method investments and projects	—	2	—	—	2
Net Cash Provided/(Used) by Investing Activities	300	196	(469)	131	158
Cash Flows from Financing Activities					
Return of capital payments to parent	(1,398)	—	—	1,398	—
Proceeds from parent intercompany loans	2,181	—	—	(2,181)	—
Payments for parent intercompany loans	(325)	(327)	—	652	—
Payments of dividends to preferred stockholders	(704)	(23)	(20)	727	(20)
Payment for treasury stock	—	—	(250)	—	(250)
Repayment of minority interest obligations	—	(4)	—	—	(4)
Proceeds from issuance of preferred stock	—	—	246	—	246
Proceeds from issuance of long-term debt	—	249	—	—	249
Deferred debt issuance costs	—	—	(46)	—	(46)
Payments for short and long-term debt	(4)	(352)	(649)	—	(1,005)
Net Cash Used by Financing Activities	(250)	(457)	(719)	596	(830)
Change in Cash from Discontinued Operations	—	29	1	—	30
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(2)	—	—	(2)
Change in Cash and Cash equivalents	(163)	(124)	(289)	—	(576)
Cash and Cash Equivalents at Beginning of Period	156	202	711	—	1,069
Cash and Cash Equivalents at End of Period	$ (7)	$ 78	$ 422	$ —	$ 493

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
Year Ended December 31, 2004

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations(a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,722	$ 389	$ —	$ (7)	$ 2,104
Operating Costs and Expenses					
Cost of operations	1,060	237	—	(7)	1,290
Depreciation and amortization	133	38	8	—	179
General, administrative and development	118	23	56	—	197
Impairment charges	3	27	15	—	45
Reorganization charges	2	—	(15)	—	(13)
Corporate relocation charges	—	—	16	—	16
Total operating costs and expenses	1,316	325	80	(7)	1,714
Operating Income/(Loss)	406	64	(80)	—	390
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	89	—	293	(382)	—
Equity in earnings of unconsolidated affiliates	92	69	(1)	—	160
Write downs and gains/(losses) on sales of equity method investments	(16)	(1)	1	—	(16)
Other income, net	7	30	5	(20)	22
Refinancing expense	—	—	(72)	—	(72)
Interest expense	—	(93)	(182)	20	(255)
Total other income	172	5	44	(382)	(161)
Income/(Loss) From Continuing Operations Before Income Taxes	578	69	(36)	(382)	229
Income tax expense/(benefit)	238	53	(217)	—	74
Income From Continuing Operations	340	16	181	(382)	155
Income from discontinued operations, net of income tax expense	3	23	5	—	31
Net Income	$ 343	$ 39	$ 186	$ (382)	$ 186

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2004

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations(a)	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 343	$ 39	$ 186	$ (382)	$ 186
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distributions in excess/(less than) equity in earnings of unconsolidated affiliates	(53)	(38)	—	90	(1)
Depreciation and amortization of nuclear fuel	133	69	13	—	215
Amortization and write-of of deferred financing costs and debt discount/premiums	—	21	49	—	70
Amortization of intangibles and out-of-market contracts	14	38	—	—	52
Amortization of unearned equity compensation	2	1	11	—	14
Write down and losses/(gains) on sale of equity method investments	16	1	(1)	—	16
Loss on sale of equipment	1	—	—	—	1
Restructuring and impairment charges	3	27	15	—	45
Changes in derivatives	(71)	(9)	6	—	(74)
Changes in deferred income taxes	26	(8)	118	(79)	57
Gain on sale of discontinued operations	(2)	(26)	5	—	(23)
Changes in collateral deposits supporting energy risk management activities	(7)	—	—	—	(7)
Cash provided by changes in other working capital, net of acquisition and disposition affects	(34)	7	126	(5)	94
Net Cash Provided by Operating Activities	371	122	528	(376)	645
Cash Flows from Investing Activities					
Capital expenditures	(82)	(28)	(9)	—	(119)
Decrease/(increase) in restricted cash, net	1	(28)	—	—	(27)
Decrease/(increase) in notes receivable	(23)	16	25	7	25
Proceeds from sale of investments	21	27	3	—	51
Proceeds from sale of equipment	4	—	—	—	4
Proceeds on sale of discontinued operations	2	251	—	—	253
Distributions/(investments) in subsidiaries	—	—	82	(82)	—
Return of capital from equity method investments/investment in projects	4	(16)	9	—	(3)
Net Cash Provided/(Used) by Investing Activities	(73)	222	110	(75)	184
Cash Flows from Financing Activities					
Capital contribution from parent	10	33	—	(43)	—
Payments of dividends	(407)	(10)	—	417	—
Payment for treasury stock	—	—	(405)	—	(405)
Proceeds from issuance of preferred stock, net	—	—	406	—	406
Proceeds from issuance of long-term debt	—	(7)	1,304	36	1,333
Deferred debt issuance costs	—	—	(26)	—	(26)
Funded letter of credit	—	—	(100)	—	(100)
Payments for short and long-term debt	(41)	(292)	(1,200)	41	(1,492)
Net Cash Used by Financing Activities	(438)	(276)	(21)	451	(284)
Change in Cash from Discontinued Operations	—	(14)	—	—	(14)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	3	—	—	3
Change in Cash and Cash equivalents	(140)	57	617	—	534
Cash and Cash Equivalents at Beginning of Period	296	144	95	—	535
Cash and Cash Equivalents at End of Period	$ 156	$ 201	$ 712	$ —	$ 1,069

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

NRG ENERGY, INC.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2006, 2005, and 2004

	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In millions)		
Allowance for doubtful accounts, deducted from accounts receivable					
Year ended December 31, 2006	$ 2	$ —	$ —	$ (1)	$ 1
Year ended December 31, 2005	1	2	—	(1)	2
Year ended December 31, 2004	—	1	—	—	1
Income tax valuation allowance, deducted from deferred tax assets					
Year ended December 31, 2006	$ 836	$ (10)	$ (81)	$ (164)	$ 581
Year ended December 31, 2005	788	22	85	(59)	836
Year ended December 31, 2004	1,321	—	(277)	(256)	788

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NRG Energy, Inc.
(Registrant)

/s/ David W. Crane

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

/s/ Robert C. Flexon

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

/s/ Carolyn J. Burke

Carolyn J. Burke,
Controller
(Principal Accounting Officer)

Date: February 28, 2007

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints David W. Crane, J. Andrew Murphy and Tanuja M. Dehne, each or any of them, such person's true and lawful attorney-in-fact and agent with full power of substitution and resubstitution for such person and in such person's name, place and stead, in any and all capacities, to sign any and all amendments to this report on Form 10-K, and to file the same with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing necessary or desirable to be done in and about the premises, as fully to all intents and purposes as such person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or his or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

In accordance with the Exchange Act, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on February 28, 2007.

Signature	Title	Date
/s/ David W. Crane David W. Crane	President, Chief Executive Officer and Director	February 28, 2007
/s/ Howard E. Cosgrove Howard E. Cosgrove	Chairman of the Board	February 28, 2007
/s/ John F. Chlebowski John F. Chlebowski	Director	February 28, 2007
/s/ Lawrence S. Coben Lawrence S. Coben	Director	February 28, 2007
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 28, 2007
/s/ William E. Hantke William E. Hantke	Director	February 28, 2007
/s/ Paul W. Hobby Paul W. Hobby	Director	February 28, 2007
/s/ Maureen Miskovic Maureen Miskovic	Director	February 28, 2007
/s/ Anne C. Schaumburg Anne C. Schaumburg	Director	February 28, 2007
/s/ Herbert H. Tate Herbert H. Tate	Director	February 28, 2007
/s/ Thomas H. Weidemeyer Thomas H. Weidemeyer	Director	February 28, 2007
/s/ Walter R. Young Walter R. Young	Director	February 28, 2007

EXHIBIT INDEX

2.1	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.(6)
2.2	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.(6)
2.3	Acquisition Agreement, dated as of September 30, 2005, by and among NRG Energy, Inc., Texas Genco LLC and the Direct and Indirect Owners of Texas Genco LLC.(13)
3.1	Amended and Restated Certificate of Incorporation.(18)
3.2	Amended and Restated By-Laws.(7)
3.3	Certificate of Designation of 4.0% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on December 20, 2004.(9)
3.4	Certificate of Designations of 3.625% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on August 11, 2005.(19)
3.5	Certificate of Designations of 5.75% Mandatory Convertible Preferred Stock, as filed with the Secretary of State of the State of Delaware on January 27, 2006.(21)
3.6	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 14, 2006.(29)
3.7	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance II LLC, as filed with the Secretary of State of Delaware on August 14, 2006.(29)
4.1	Supplemental Indenture dated as of December 30, 2005, among NRG Energy, Inc., the subsidiary guarantors named on Schedule A thereto and Law Debenture Trust Company of New York, as trustee.(15)
4.2	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto dated as of January 6, 2004, together with Annex A to the Common Agreement.(2)
4.3	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.(2)
4.4	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.(2)
4.5	Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.(3)
4.6	Registration Rights Agreement, dated December 21, 2004, by and among NRG Energy, Inc., Citigroup Global Markets Inc. and Deutsche Bank Securities Inc.(8)
4.7	Specimen of Certificate representing common stock of NRG Energy, Inc.(28)
4.8	Indenture, dated February 2, 2006, among NRG Energy, Inc. and Law Debenture Trust Company of New York.(22)
4.9	First Supplemental Indenture, dated February 2, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.250% Senior Notes due 2014.(22)
4.10	Second Supplemental Indenture, dated February 2, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.375% Senior Notes due 2016.(22)
4.11	Form of 7.250% Senior Note due 2014.(22)
4.12	Form of 7.375% Senior Note due 2016.(22)
4.13	Third Supplemental Indenture, dated March 14, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.250% Senior Notes due 2014.(24)

4.14	Fourth Supplemental Indenture, dated March 14, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.375% Senior Notes due 2016.(24)
4.15	Fifth Supplemental Indenture, dated April 28, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.250% Senior Notes due 2014.(25)
4.16	Sixth Supplemental Indenture, dated April 28, 2006, among NRG, the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.375% Senior Notes due 2016.(25)
4.17	Seventh Supplemental Indenture, dated November 13, 2006, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.250% Senior Notes due 2014.(30)
4.18	Eighth Supplemental Indenture, dated November 13, 2006, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.375% Senior Notes due 2016.(30)
4.19	Ninth Supplemental Indenture, dated November 21, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.375% Senior Notes due 2017.(31)
4.20	Form of 7.375% Senior Note due 2017.(31)
10.1	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.(4)
10.2	Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.(4)
10.3	Asset Sales Agreement, dated December 23, 1998, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(5)
10.4	Amendment to the Asset Sales Agreement, dated June 11, 1999, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(5)
10.5*	Severance Agreement between NRG Energy, Inc. and John P. Brewster dated July 23, 2003.(2)
10.6*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.(17)
10.7*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.(17)
10.8*	Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.(10)
10.9*	Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.(10)
10.10*	Form of NRG Energy, Inc. Long Term Incentive Plan Performance Unit Agreement.(14)
10.11*	Annual Incentive Plan for Designated Corporate Officers.(11)
10.12*	Letter Agreement, dated March 5, 2004, between NRG Energy, Inc. and John P. Brewster.(12)
10.13*	Letter Agreement, dated March 5, 2004, between NRG Energy, Inc. and Timothy W. O'Brien.(12)
10.14*	Letter Agreement, dated February 19, 2004, between NRG Energy, Inc. and Robert C. Flexon.(12)
10.15	Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(17)
10.16	Commitment Letter, dated February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(17)
10.17	Purchase Agreement (West Coast Power) dated as of December 27, 2005, by and among NRG Energy, Inc., NRG West Coast LLC (Buyer), DPC II Inc. (Seller) and Dynegy, Inc.(16)
10.18	Purchase Agreement (Rocky Road Power), dated as of December 27, 2005, by and among Termo Santander Holding, L.L.C.(Buyer), Dynegy, Inc., NRG Rocky Road LLC (Seller) and NRG Energy, Inc.(16)
10.19*	Letter Agreement, dated June 21, 2005, between NRG Energy, Inc. and Kevin T. Howell.(20)
10.20	Stock Purchase Agreement, dated as of August 10, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(19)

10.21	Accelerated Share Repurchase Agreement, dated as of August 11, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(19)
10.22	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.(23)
10.23	Amended and Restated Master Power Purchase and Sale Agreement, dated February 2, 2006, by and between J. Aron & Company and Texas Genco II, LP (including the cover sheet and confirmation letter thereto) (portions of this document have been omitted pursuant to a request for confidential treatment and filed separately with the SEC).(27)
10.24	Terms and Conditions of Sale, dated as of October 5, 2005, between Texas Genco II LP and Freight Car America, Inc., (including the Proposal Letter and Amendment thereto) (portions of this document have been omitted pursuant to a request for confidential treatment and filed separately with the SEC).(27)
10.25*	Employment Agreement, dated March 3, 2006, between NRG Energy, Inc. and David Crane.(27)
10.26*	CEO and CFO Compensation Table.(32)
10.27*	NRG Energy, Inc. Director Compensation Table.(26)
10.28	Limited Liability Company Agreement of NRG Common Stock Finance I LLC.(29)
10.29	Limited Liability Company Agreement of NRG Common Stock Finance II LLC.(29)
10.30	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC.(29)
10.31	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance II LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC, as agent.(29)
10.32	Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent.(29)
10.33	Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance II LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent.(29)
10.34	Common Interest Purchase Agreement, dated August 4, 2006, between NRG Energy, Inc. and NRG Common Stock Finance I LLC.(29)
10.35	Common Interest Purchase Agreement, dated August 4, 2006, between NRG Energy, Inc. and NRG Common Stock Finance II LLC.(29)
10.36	Credit Agreement, dated February 2, 2006, as amended and restated on November 21, 2006, among NRG Energy, Inc., a Delaware corporation, the Lenders from time to time party thereto, Morgan Stanley Senior Funding, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as joint lead book runners and joint lead arrangers, Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley & Co. Incorporated, as collateral agent, and Merrill Lynch Capital Corporation, as syndication agent.(29)
10.37*	Amended and Restated Long-Term Incentive Plan, dated December 8, 2006.(32)
10.38*	NEO 2006 AIP Payout and 2007 Base Salary Table.(1)
10.39*	NRG Energy, Inc. Executive and Key Management Change-in-Control and General Severance Agreement, dated May 24, 2006.(1)
12.1	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges.(1)
12.2	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividend Requirements.(1)
21	Subsidiaries of NRG Energy. Inc.(1)
23.1	Consent of KPMG LLP.(1)
31.1	Rule 13a-14(a)/15d-14(a) certification of David W. Crane.(1)
31.2	Rule 13a-14(a)/15d-14(a) certification of Robert C. Flexon.(1)
31.3	Rule 13a-14(a)/15d-14(a) certification of Carolyn J. Burke.(1)
32	Section 1350 Certification.(1)

* Exhibit relates to compensation arrangements.

(1) Filed herewith.

(2) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 16, 2004.

(3) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 31, 2003.

(4) Incorporated herein by reference to NRG Energy Inc.'s Registration Statement on Form S-1, as amended, Registration No. 333-33397.

(5) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 1999.

(6) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on November 19, 2003.

(7) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on March 3, 2005.

(8) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.

(9) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.

(10) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended September 30, 2004.

(11) Incorporated herein by reference to NRG Energy, Inc.'s 2004 proxy statement on Schedule 14A filed on July 12, 2004.

(12) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended March 31, 2004.

(13) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on October 3, 2005.

(14) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 2005.

(15) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on January 4, 2006.

(16) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 28, 2005.

(17) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 30, 2005.

(18) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on May 24, 2005.

(19) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 11, 2005.

(20) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 3, 2005.

(21) Incorporated herein by reference to NRG Energy, Inc.'s Form 8-A filed on January 27, 2006.

(22) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on February 6, 2006.

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

(24) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on March 16, 2006.

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

(26) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on May 4, 2006.

(27) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 7, 2006.

(28) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q filed on August 4, 2006.

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

(30) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on November 14, 2006.

(31) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on November 27, 2006.

(32) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 14, 2006.

Exhibit 10.38

NRG Energy, Inc
Named Executive Officer 2006 AIP Payout and 2007 Base Salary Table

Name	Title	2006 Annual Incentive Plan Payout	2007 Base Salary
David Crane	President, Chief Executive Officer and Director	1,267,626	1,000,000
Robert C. Flexon	Executive Vice President and Chief Financial Officer	451,888	550,000
Kevin T. Howell	Executive Vice President, Commercial Operations	323,180	400,000
John P. Brewster	Executive Vice President, Development Engineering Procurement and Construction	231,416	340,000
Steve Winn	Executive Vice President, Strategy and Environmental and New Business	245,063	370,000

NRG Energy, Inc.

Executive & Key Management
Change-in-Control
and General Severance Plan

(Amended May 24, 2006)

Contents

NRG Energy, Inc.
Executive & Key Management Change-in-Control
and General Severance Plan

Article 1. Establishment and Term of the Plan

1.1 Establishment of the Plan. NRG Energy, Inc. (hereinafter referred to as the "Company") hereby establishes a severance plan to be known as the "NRG Energy, Inc. Executive Change-in-Control and General Severance Plan" (the "Plan"). The Plan provides severance benefits to certain employees of the Company ("Executives") upon certain terminations of employment from the Company.

The Company considers the establishment and maintenance of a sound and vital management to be essential to protecting and enhancing the best interests of the Company and its stockholders. In this connection, the Company recognizes that, as is the case with many publicly held corporations, the possibility of a change in control may arise and that such possibility, and the uncertainty and questions which it may raise among management, may result in the departure or distraction of management personnel to the detriment of the Company and its stockholders.

Accordingly, the Board has determined that appropriate steps should be taken to reinforce and encourage the continued attention and dedication of members of the Company's management to their assigned duties without distraction in circumstances arising from the possibility of a Change in Control of the Company.

1.2 Initial Term. This Plan will commence on May 24, 2006 (the "Effective Date") and shall continue in effect for a period of three (3) years (the "Initial Term").

1.3 Successive Periods. The term of this Plan shall automatically be extended for one (1) additional year at the end of the Initial Term, and then again after each successive one (1) year period thereafter (each such one (1) year period following the Initial Term is referred to as a "Successive Period"). However, the Committee may terminate this Plan at the end of the Initial Term, or at the end of any Successive Period thereafter, by giving the Executives written notice of intent to terminate the Plan, delivered at least six (6) months prior to the end of such Initial Term or Successive Period. If such notice is properly delivered by the Company, this Plan, along with all corresponding rights, duties, and covenants, shall automatically expire at the end of the Initial Term or Successive Period then in progress.

1.4 Change-in-Control Renewal. Notwithstanding the provisions of Section 1.3 above, in the event that a Change in Control of the Company occurs during the Initial Term or any Successive Period, upon the effective date of such Change in Control, the term of this Plan shall automatically and irrevocably be renewed for a period of two (2) years from the effective date of such Change in Control. Further, this Plan may be assigned to the successor in such Change in Control, as further provided in Article 8 herein. This Plan shall thereafter automatically terminate following such two (2) year Change-in-Control renewal period.

Article 2. Definitions

Whenever used in this Plan, the following terms shall have the meanings set forth below and, when the meaning is intended, the initial letter of the word is capitalized.

(a) **"Base Salary"** means the greater of the Executive's annual rate of salary, whether or not deferred, at: (i) the Effective Date of Termination or (ii) at the date of the Change in Control.

(b) **"Beneficiary"** means the persons or entities designated or deemed designated by the Executive pursuant to Section 8.5 herein.

(c) **"Board"** means the Board of Directors of the Company.

(d) **"Cause"** shall mean one or more of the following:

(i) The conviction of, or an agreement to a plea of *nolo contendere* to, any felony or other crime involving moral turpitude; or

(ii) The Executive's willful and continuing refusal to substantially perform duties as reasonably directed by the Board under this or any other agreement (after receipt of written notice from the Board setting forth such duties and responsibilities to be performed); or

(iii) In carrying out the Executive's duties, the Executive engages in conduct that constitutes willful gross neglect or willful gross misconduct which, in either case, results in demonstrable harm to the business, operations, prospects, or reputation of the Company; or

(iv) Any other material breach of Article 4 of this Plan which is not cured to the Board's reasonable satisfaction within fifteen (15) days after written notice thereof to the Executive.

For purposes of this Plan, there shall be no termination for Cause pursuant to subsections (i) through (iv) above, unless a written notice, containing a detailed description of the grounds constituting Cause hereunder, is delivered to the Executive stating the basis for the termination. Upon receipt of such notice, the Executive shall be given thirty (30) days to fully cure and remedy the neglect or conduct that is the basis of such claim. If the Executive fails to fully cure and remedy such neglect or misconduct within such thirty (30) day period, the Executive shall have an opportunity to be heard before the full Board. After such hearing, a termination for Cause shall only occur if there is a vote of three-quarters (3/4) of the Board to terminate the Executive for Cause.

(e) **“Change in Control”** shall mean the first to occur of any of the following events:

(i) Any “person” (as that term is used in Sections 13 and 14(d)(2) of the Securities Exchange Act of 1934 (“Exchange Act”)) becomes the “Beneficial Owner” (as that term is used in Section 13(d) of the Exchange Act), directly or indirectly, of fifty percent (50%) or more of the Company’s capital stock entitled to vote in the election of directors; or

(ii) Persons who on the Effective Date constitute the Board (the “Incumbent Directors”) cease for any reason, including without limitation, as a result of a tender offer, proxy contest, merger, or similar transaction, to constitute at least a majority thereof, provided that any person becoming a director of the Company subsequent to the Effective Date shall be considered an Incumbent Director if such person’s election or nomination for election was approved by a vote of at least two-thirds (2/3) of the Incumbent Directors; but provided further, that any such person whose initial assumption of office is in connection with an actual or threatened election contest relating to the election of members of the Board or other actual or threatened solicitation of proxies or consents by or on behalf of a “person” (as defined in Sections 13(d) and 14(d) of the Exchange Act) other than the Board, including by reason of agreement intended to avoid or settle any such actual or threatened contest or solicitation, shall not be considered an Incumbent Director; or

(iii) Consummation of a reorganization, merger, consolidation, or sale or other disposition of all or substantially all of the assets of the Company (a “Business Combination”), in each case, unless, following such Business Combination, all or substantially all of the individuals and entities who were the beneficial owners of outstanding voting securities of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more than fifty percent (50%) of the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the company resulting from such Business Combination (including, without limitation, a company which, as a result of such transaction, owns the Company or all or substantially all of the Company’s assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination, of the outstanding voting securities of the Company; or

(iv) The stockholders of the Company approve any plan or proposal for the liquidation or dissolution of the Company.

(f) **“Code”** means the United States Internal Revenue Code of 1986, as amended, and any successors thereto.

(g) **“Committee”** means the Compensation Committee of the Board or any other committee appointed by the Board to perform the functions of the Compensation Committee.

(h) **“Company”** means NRG Energy, Inc., a Delaware corporation, or any successor thereto as provided in Section 7 herein.

(i) **“Disability”** shall mean the Executive’s inability to perform the essential duties, responsibilities, and functions of his position with the Company and its affiliates as a result of any mental or physical disability or incapacity even with reasonable accommodations of such disability or incapacity, provided by the Company and its affiliates, or if providing such accommodations would be unreasonable, for a period of twelve (12) months. The Executive shall cooperate in all respects with the Company if a question arises as to whether he has become disabled (including, without limitation, submitting to an examination by a medical doctor or other health care specialists selected by the Company and reasonably acceptable to the Executive and authorizing such medical doctor or such other health care specialist to discuss the Executive’s condition with the Company).

(j) **“Effective Date”** means the commencement date of this Plan as specified in Section 1.2 of this Plan.

(k) **“Effective Date of Termination”** means the date on which a Qualifying Termination occurs, as defined hereunder, which triggers the payment of Severance Benefits hereunder.

(l) **“Former Parent Company”** means Xcel Energy, Inc., a Minnesota corporation, or any successor thereto.

(m) **“Good Reason”** shall mean without the Executive’s express written consent the occurrence of any one or more of the following:

(i) The Company materially reduces the amount of the Executive’s then current Base Salary or the target for his annual bonus; or

(ii) A material reduction in the Executive’s benefits under or relative level of participation in the Company’s employee benefit or retirement plans, policies, practices, or arrangements in which the Executive participates as of the Effective Date of this Plan; or

(iii) A material diminution in the Executive’s title, authority, duties, or responsibilities or the assignment of duties to the Executive which are materially inconsistent with his position; or

(iv) The failure of the Company to obtain in writing the obligation to perform or be bound by the terms of this Plan by any successor to the Company or a purchaser of all or substantially all of the assets of the Company within fifteen (15) days after a merger, consolidation, sale, or similar transaction.

For purposes of this Plan, the Executive is not entitled to assert that his termination is for Good Reason unless the Executive gives the Board written notice of the event or events which are the basis for such claim within ninety (90) days after the event or events occur, describing such claim in reasonably sufficient detail to allow the Board to address the event or events and a period of not less than thirty (30) days after to cure or fully remedy the alleged condition.

(n) **"Key Employee"** means any Eligible Employee described in section 409A(a)(2)(B)(i) of the Code.

(o) **"Notice of Termination"** shall mean a written notice which shall indicate the specific termination provision in this Plan relied upon, and shall set forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Executive's employment under the provision so indicated.

(p) **"Qualifying Termination"** means:

(i) If such event occurs within twenty-four (24) months immediately following a Change in Control:

(A) An involuntary termination of the Executive's employment by the Company for reasons other than Cause pursuant to a Notice of Termination delivered to the Executive by the Company; or

(B) A voluntary termination by the Executive for Good Reason pursuant to a Notice of Termination delivered to the Company by the Executive; or

(ii) If such event occurs at any other time:

(A) An involuntary termination of the Executive's employment by the Company for reasons other than Cause pursuant to a Notice of Termination delivered to the Executive by the Company.

(q) **"Retirement"** shall have the meaning ascribed to such term in the Company's tax-qualified retirement plan or under the successor or replacement of such retirement plan if it is then no longer in effect.

(r) **"Severance Benefits"** means the payment of Change-in-Control or General (as appropriate) Severance compensation as provided in Article 3 herein.

Article 3. Severance Benefits

3.1 Right to Severance Benefits.

(a) **Change-in-Control Severance Benefits**. The Executive shall be entitled to receive from the Company Change-in-Control Severance Benefits, as described in Section 3.2 herein, if a Qualifying Termination of the Executive's employment has occurred within twenty-four (24) months immediately following a Change in Control of the Company.

(b) **General Severance Benefits**. The Executive (other than any Tier III Executive) shall be entitled to receive from the Company General Severance Benefits, as described in Section 3.3 herein, if a Qualifying Termination of the Executive's employment has occurred other than during the twenty-four (24) months immediately following a Change in Control.

(c) **No Severance Benefits**. The Executive shall not be entitled to receive Severance Benefits if the Executive's employment with the Company ends for reasons other than a Qualifying Termination.

(d) **General Release and Acknowledgement of Restrictive Covenants** . As a condition to receiving Severance Benefits under either Section 3.2 or 3.3 herein, the Executive shall be obligated to execute a general release of claims in favor of the Company, its current and former affiliates and stockholders, and the current and former directors, officers, employees, and agents of the Company in a form acceptable to the Company. The Executive must also execute a notice acknowledging the restrictive covenants in Article 4.

(e) **No Duplication of Severance Benefits**. If the Executive becomes entitled to Change-in-Control Severance Benefits, the Severance Benefits provided for under Section 3.2 hereunder shall be in lieu of all other Severance Benefits provided to the Executive under the provisions of this Plan and any other Company-related or Former Parent Company-related severance plans, programs, or agreements including, but not limited to, the Severance Benefits under Section 3.3 herein. Likewise, if the Executive becomes entitled to General Severance Benefits, the Severance Benefits provided under Section 3.3 hereunder shall be in lieu of all other Severance Benefits provided to the Executive under the provisions of this Plan and any other Company-related severance plans, programs, or other agreements including, but not limited to, the Severance Benefits under Section 3.2 herein.

3.2 Description of Change-in-Control Severance Benefits . In the event the Executive becomes entitled to receive Change-in-Control Severance Benefits, as provided in Section 3.1(a) herein, the Company shall provide the Executive with the following:

(a) A lump-sum amount paid within forty-five (45) calendar days of the Effective Date of Termination equal to the Executive's unpaid Base Salary, accrued vacation pay, unreimbursed business expenses, and all other items earned by and owed to the Executive through and including the Effective Date of Termination.

(b) A benefit amount equal to: (i) two and ninety-nine one-hundredths (2.99) for Tier I Executives (as identified in Appendix A), or (ii) two (2) for Tier II Executives (as identified in Appendix A) times the sum of the following: (A) the Executive's

Base Salary and (B) the Executive's annual target bonus opportunity in the year of termination. A Tier III Executive (as identified in Appendix A) shall be entitled to a benefit amount equal to (i) one and one-half (1.5) for Tier III – Level 1 Executives (as identified on Appendix A), (ii) one (i) for Tier III-Level 2 Executives (as identified on Appendix A) times the Executive's Base Salary. Unless otherwise determined by the Board, and at the Board's discretion, such benefit amount shall be paid out over a period of: (i) thirty-six (36) months for Tier I Executives (as identified in Appendix A), (ii) twenty-four (24) months for Tier II Executives (as identified in Appendix A), (iii) eighteen (18) months for Tier III-Level 1 Executives (as identified on Appendix A), or (iv) twelve (12) months for Tier IV-Level 2 Executives (as identified on appendix A) in accordance with the payroll procedures of the Company, to commence on the next regularly scheduled payroll cycle immediately following the date on which the Executive's general release becomes effective and irrevocable.

(c) In the case of Tier I and Tier II Executives only, a lump-sum amount, paid within forty-five (45) calendar days of the Effective Date of Termination, equal to the Executive's then current target bonus opportunity established under the bonus plan in which the Executive is then participating, for the plan year in which a Qualifying Termination occurs, adjusted on a pro rata basis based on the number of days the Executive was actually employed during the bonus plan year in which the Qualifying Termination occurs.

(d) In the case of Tier I and Tier II Executives only, continuation for eighteen (18) months of the Executive's medical and dental coverage.

These benefits shall be provided by the Company to the Executive beginning immediately upon the Effective Date of Termination. Such benefits shall be provided to the Executive at the same coverage level and cost to the Executive as in effect immediately prior to the Executive's Effective Date of Termination.

Notwithstanding the above, these medical benefits shall be discontinued prior to the end of the stated continuation period in the event the Executive receives substantially similar benefits from a subsequent employer, as determined solely by the Committee in good faith. For purposes of enforcing this offset provision, the Executive shall be deemed to have a duty to keep the Company informed as to the terms and conditions of any subsequent employment and the corresponding benefits earned from such employment, and shall provide, or cause to provide, to the Company in writing correct, complete, and timely information concerning the same.

(e) Treatment of outstanding long-term incentives shall be in accordance with the governing plan document and award agreements, if any.

(f) Notwithstanding anything herein to the contrary, in the case of any Key Employee such Change in Control Severance Benefits shall be paid as soon as practicable following the date six months after the Effective Date of Termination; provided, the foregoing shall only apply to the extent the Company determines such delay is required under section 409A of the Code.

3.3 Description of General Severance Benefits . Only Tier I and Tier II Executives shall be eligible to receive General Severance Benefits under the Plan; Tier III Executives shall not be eligible to receive General Severance Benefits under the Plan (but may be eligible to receive benefits under the Company's generally applicable severance plan, as may be in effect from time to time). In the event the Executive becomes entitled to receive General Severance Benefits as provided in Section 3.1(b) herein, the Company shall provide the Executive with the following:

(a) A lump-sum amount, paid within forty-five (45) calendar days of the Effective Date of Termination, equal to the Executive's unpaid Base Salary, accrued vacation pay, unreimbursed business expenses, and all other items earned by and owed to the Executive through and including the Effective Date of Termination.

(b) A benefit amount equal to one and one-half (1.5) for Tier I and Tier II Executives (as identified in Appendix A) times the Executive's Base Salary. Such benefit amount shall be paid out over a period of eighteen (18) months in accordance with the payroll procedures of the Company, to commence on the next regularly scheduled payroll cycle immediately following the date on which the Executive's general release becomes effective and irrevocable.

(c) Continuation for eighteen (18) months of the Executive's medical and dental insurance coverage.

These benefits shall be provided by the Company to the Executive beginning immediately upon the Effective Date of Termination. Such benefits shall be provided to the Executive at the same coverage level and cost to the Executive as in effect immediately prior to the Executive's Effective Date of Termination.

Notwithstanding the above, these medical insurance benefits shall be discontinued prior to the end of the stated continuation period in the event the Executive receives substantially similar benefits from a subsequent employer, as determined solely by the Committee in good faith. For purposes of enforcing this offset provision, the Executive shall be deemed to have a duty to keep the Company informed as to the terms and conditions of any subsequent employment and the corresponding benefits earned from such employment, and shall provide, or cause to provide, to the Company in writing correct, complete, and timely information concerning the same.

(d) Treatment of outstanding long-term incentives shall be in accordance with the governing plan document and award agreements, if any.

(e) Notwithstanding anything herein to the contrary, in the case of any Key Employee such General Severance Benefits shall be paid as soon as practicable following the date six months after the Effective Date of Termination; provided, the foregoing shall only apply to the extent the Company determines such delay is required under section 409A of the Code.

Article 4. Confidentiality and Noncompetition

In the event the Executive becomes entitled to receive Change-in-Control Severance Benefits as provided in Section 3.2 herein or General Severance Benefits as provided in Section 3.3 herein, the following shall apply:

(a) **Confidential Information**. The Executive acknowledges that the information, observations, and data (including trade secrets) obtained by him while employed by the Company concerning the business or affairs of the Company or any of its affiliates ("Confidential Information") are the property of the Company or such affiliate. Therefore, except in the course of the Executive's duties to the Company or as may be compelled by law or appropriate legal process, the Executive agrees that he shall not disclose to any person or entity or use for his own purposes any Confidential Information or any confidential or proprietary information of other persons or entities in the possession of the Company and its affiliates ("Third Party Information"), without the prior written consent of the Board, unless and to the extent that the Confidential Information or Third Party Information becomes generally known to and available for use by the public other than as a result of the Executive's acts or omissions. Except in the course of the Executive's duties to Company or as may be compelled by law or appropriate legal process, the Executive will not, during his employment with the Company, or permanently thereafter, directly or indirectly use, divulge, disseminate, disclose, lecture upon, or publish any Confidential Information, without having first obtained written permission from the Board to do so. As of the Effective Date of Termination, the Executive shall deliver to the Company, or at any other time the Company may reasonably request, all memoranda, notes, plans, records, reports, computer files, disks and tapes, printouts and software and other documents and data (and copies thereof) embodying or relating to Third Party Information, Confidential Information, or the business of the Company, or its affiliates which he may then possess or have under his control.

(b) **Intellectual Property, Inventions, and Patents**. The Executive acknowledges that all discoveries, concepts, ideas, inventions, innovations, improvements, developments, methods, trade secrets, designs, analyses, drawings, reports, patent applications, copyrightable work and mask work (whether or not including any confidential information), and all registrations or applications related thereto, all other proprietary information and all similar or related information (whether or not patentable) which may relate to the Company's or any of its affiliates' actual or anticipated business, research and development, or existing or future products or services and which are conceived, developed, or made by the Executive (whether alone or jointly with others) while employed by the Company and its affiliates ("Work Product"), belong to the Company or such affiliate. The Executive shall promptly disclose such Work Product to the Board and, at the Company's expense, perform all actions reasonably requested by the Board (whether during or after the Executive's employment with the Company) to establish and confirm such ownership (including, without limitation, assignments, consents, powers of attorney, and other instruments). The Executive acknowledges that all applicable Work Product shall be deemed to constitute “works made for hire” under the U.S. Copyright Act of 1976, as amended. To the extent any Work Product is not deemed a work made for hire, then the Executive hereby assigns to the Company or such affiliate all right, title, and interest in and to such Work Product, including all related intellectual property rights.

The Executive is hereby advised that the above paragraph regarding the Company’s and its affiliates’ ownership of Work Product does not apply to any invention for which no equipment, supplies, facilities, or trade secret information of the Company or any affiliate was used and which was developed entirely on the Executive’s own time, unless: (i) the invention relates to the business of the Company or any affiliate or to the Company’s or any affiliate’s actual or demonstrably anticipated research or development, or (ii) the invention results from any work performed by the Executive for the Company or any affiliate.

(c) **Noncompete**. In further consideration of the compensation to be paid to the Executive hereunder, the Executive acknowledges that during the course of his employment with the Company and its affiliates he shall become familiar with the Company’s trade secrets and with other Confidential Information concerning the Company and its affiliates and that his services shall be of special, unique, and extraordinary value to the Company and its affiliates, and therefore, the Executive agrees that, during the Executive’s employment with the Company and for one (1) year thereafter (the “Noncompete Period”), the Executive shall not directly or indirectly own any interest in, manage, control, participate in, consult with, render services for, be employed in an executive, managerial, or administrative capacity by, or in any manner engage in any company engaged in the business of wholesale power generation which competes with the businesses of the Company or its affiliates, as such businesses exist or are in process during the Executive’s employment with the Company, within any geographical area in which the Company or its affiliates engage or have definitive plans to engage in such businesses. Nothing herein shall prohibit the Executive from being a passive owner of not more than two percent (2%) of the outstanding stock of any class of a corporation which is publicly traded, so long as the Executive has no active participation in the business of such corporation. Notwithstanding the foregoing, the provisions of this Article 4(c) shall not apply in the case of termination of the Executive’s employment pursuant to any material breach of the Company’s obligations under Article 3 which remains uncured for more than twenty (20) days after notice is received from the Executive of such breach, which such notice shall include a detailed description of the grounds constituting such breach.

(d) **Nonsolicitation**. During the Noncompete Period, the Executive shall not directly or indirectly through another person or entity: (i) induce or attempt to induce any employee of the Company or any of its affiliates to leave the employ of the Company or such affiliate, or in any way interfere with the relationship between the Company or any affiliate and any employee thereof; (ii) hire any person who was an employee of the Company or any affiliate during the last six (6) months of the Executive’s employment with the Company; or (iii) induce or attempt to induce any customer, supplier, licensee, licensor, franchisee, or other business relation of the Company or any affiliate to cease doing business with the Company or such affiliate, or in any interfere with the relationship between any such customer, supplier, licensee, or business relation and the Company or any affiliate (including, without limitation, making any negative or disparaging statements or communications regarding the Company or its affiliates).

(e) **Duration, Scope, or Area**. If, at the time of enforcement of this Article 4, a court shall hold that the duration, scope, or area restrictions stated herein are unreasonable under circumstances then existing, the parties agree that the maximum duration, scope, or area reasonable under such circumstances shall be substituted for the stated duration, scope, or area and that the court shall be allowed to revise the restrictions contained herein to cover the maximum period, scope, and area permitted by law.

(f) **Company Enforcement**. In the event of a breach or a threatened breach by the Executive of any of the provisions of this Article 4, the Company would suffer irreparable harm, and in addition and supplementary to other rights and remedies existing in its favor, the Company shall be entitled to specific performance and/or injunctive or other equitable relief from a court of competent jurisdiction in order to enforce or prevent any violations of the provisions hereof (without posting a bond or other security). In addition, in the event of a breach or violation by the Executive of Article 4(c), the Noncompete Period shall be automatically extended by the amount of time between the initial occurrence of the breach or violation and when such breach or violation has been duly cured.

Article 5. Excise Tax Equalization Payment

In the event that any payment or benefit made or provided to or for the benefit of a Tier I or Tier II Executive in connection with this Plan or his employment with the Company or the termination thereof (a "Payment") is determined to be subject to any excise tax ("Excise Tax") imposed by Section 4999 of the Code (or any successor to such Section), the Company shall pay to such Executive, prior to the time any Excise Tax is payable with respect to such Payment (through withholding or otherwise), an additional amount (a "Gross-Up Payment") which, after the imposition of all income, employment, excise and other taxes, penalties and interest thereon, is equal to the sum of: (i) the Excise Tax on such Payment, plus (ii) any penalty and interest assessments associated with such Excise Tax. The determination of whether any Payment is subject to an Excise Tax and, if so, the amount and time of any Gross-Up Payment pursuant to this Article 5 shall be made by an independent auditor (the "Auditor") jointly selected by the parties and paid by the Company. Unless the Executive agrees otherwise in writing, the Auditor shall be a nationally recognized United States public accounting firm that has not, during the two (2) years preceding the date of its selection, acted in any way on behalf of the Company or any of its affiliates. If the parties cannot agree on the firm to serve as the Auditor, then the parties shall each select one (1) accounting firm and those two (2) firms shall jointly select the accounting firm to serve as the Auditor. The parties shall cooperate with each other in connection with any Proceeding, defined as any threatened or actual action, suit, or proceeding, whether civil, criminal, administrative, investigative, appellate, or other, or Claim, defined as any claim, demand, request, investigation, dispute, controversy, threat, discovery request, or request for testimony or information, relating to the existence or amount of any liability for Excise Tax. All expenses relating to any such Proceeding or Claim (including attorneys' fees and other expenses incurred by the Executive in connection therewith) shall be paid by the Company promptly upon demand by the Executive, and any such payment shall be subject to a Gross-Up Payment under this Article 5 in the event that the Executive is subject to Excise Tax on such payment. This Article 5 shall apply irrespective of whether a Change in Control has occurred.

Article 6. Legal Fees and Notice

6.1 Payment of Legal Fees. Except as otherwise agreed to by the parties, the Company shall pay the Executive for costs of litigation or other disputes including, without limitation, reasonable attorneys' fees incurred by the Executive in asserting any claims or defenses under this Plan, except that the Executive shall bear his own costs of such litigation or disputes (including, without limitation, attorneys' fees) if the court (or arbitrator) finds in favor of the Company with respect to any claims or defenses asserted by the Executive.

6.2 Notice. Any notices, requests, demands, or other communications provided for by this Plan shall be sufficient if in writing and if sent by registered or certified mail to the Executive at the last address he or she has filed in writing with the Company or, in the case of the Company, at its principal offices.

Article 7. Successors and Assignment

7.1 Successors to the Company. The Company shall require any successor (whether direct or indirect, by purchase, merger, reorganization, consolidation, acquisition of property or stock, liquidation, or otherwise) of all or a significant portion of the assets of the Company by agreement, in form and substance satisfactory to the Executive, to expressly assume and agree to perform under this Plan in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place. Regardless of whether such agreement is executed, the terms of this Plan shall be binding upon any successor in accordance with the operation of law and such successor shall be deemed the “Company” for purposes of this Plan.

7.2 Assignment by the Executive. This Plan shall inure to the benefit of and be enforceable by the Executive’s personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees, and legatees. If the Executive dies while any amount would still be payable to him or her hereunder had he or she continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with the terms of this Plan to the Executive’s Beneficiary. If the Executive has not named a Beneficiary, then such amounts shall be paid to the Executive’s devisee, legatee, or other designee, or if there is no such designee, to the Executive’s estate.

Article 8. Miscellaneous

8.1 Employment Status. Except as may be provided under any other agreement between the Executive and the Company, the employment of the Executive by the Company is “at will” and may be terminated by either the Executive or the Company at any time, subject to applicable law.

8.2 Entire Plan. This Plan supersedes any prior agreements or understandings, oral or written, between the parties hereto, with respect to the subject matter hereof, and constitutes the entire agreement of the parties with respect thereto. Without limiting the generality of the foregoing sentence, this Plan completely supersedes any and all prior employment agreements entered into by and between the Company and the Executive, and all amendments thereto, in their entirety.

8.3 Severability. In the event that any provision or portion of this Plan shall be determined to be invalid or unenforceable for any reason, the remaining provisions of this Plan shall be unaffected thereby and shall remain in full force and effect.

8.4 Tax Withholding. The Company may withhold from any benefits payable under this Plan all federal, state, city, or other taxes as may be required pursuant to any law or governmental regulation or ruling.

8.5 Beneficiaries. The Executive may designate one (1) or more persons or entities as the primary and/or contingent beneficiaries of any amounts to be received under this Plan. Such designation must be in the form of a signed writing acceptable to the Board or the Board’s designee. The Executive may make or change such designation at any time.

8.6 Payment Obligation Absolute. The Company’s obligation to make the payments provided for herein shall be absolute and unconditional, and shall not be affected by any circumstances, including, without limitation, any offset, counterclaim, recoupment, defense, or other right which the Company may have against the Executive or anyone else.

Except as provided in Sections 3.2(d) and 3.3(c) of this Plan, the Executive shall not be obligated to seek other employment in mitigation of the amounts payable or arrangements made under any provision of this Plan, and the obtaining of any such other employment shall in no event effect any reduction of the Company's obligations to make the payments and arrangements required to be made under this Plan.

8.7 Contractual Rights to Benefits. Subject to approval and ratification by the Board of Directors, this Plan establishes and vests in the Executive a contractual right to the benefits to which he or she is entitled hereunder. However, nothing herein contained shall require or be deemed to require, or prohibit or be deemed to prohibit, the Company to segregate, earmark, or otherwise set aside any funds or other assets, in trust or otherwise, to provide for any payments to be made or required hereunder.

8.8 Modification. No provision of this Plan may be modified, waived, or discharged unless such modification, waiver, or discharge is agreed to in writing and signed by each and every Executive then covered by the Plan and by an authorized member of the Committee, or by the respective parties' legal representatives and successors.

8.9 Gender and Number. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine; the plural shall include the singular and the singular shall include the plural.

8.10 Applicable Law. To the extent not preempted by the laws of the United States, the laws of the state of New Jersey shall be the controlling law in all matters relating to this Plan.

IN WITNESS WHEREOF, the Company has executed this Plan on this 24th day of May 2006.

ATTEST

NRG Energy, Inc.

/S/ DAVID W. CRANE
David W. Crane
President and Chief Executive Officer

Exhibit 12.1

NRG Energy, Inc

Computation of Ratio of Earnings to Fixed Charges

	For the Year Ended December 2006	For the Year Ended December 2005	For the Year Ended December 2004	For the Period December 6, 2003 Through December 31, 2003	For the Period January 1, 2003 Through December 5, 2003	For the Year Ended December 2002
	(In millions except ratio)					
Earnings:						
Income/(loss) before taxes from continuing Operations before income tax	$ 880	$ 119	$ 229	$ 11	$ 3,192	$ (2,857)
Minority interest in earnings		—	—	—		
Less:						
Undistributed equity in earning of unconsolidated affiliates	(33)	(8)	(1)	2	(41)	(22)
Capitalized interest	(5)	—	—	—	—	(46)
Add:						
Fixed Charges	608	200	259	18	297	474
Total Earnings:	$ 1,450	$ 311	$ 487	$ 31	$ 3,448	$ (2,451)
Fixed Charges:						
Interest expense	$ 571	$ 186	$ 232	$ 16	$ 275	$ 397
Interest capitalized	5	—	—	—	—	46
Amortization of debt issuance costs	22	6	9	1	18	27
Amortization of debt discount/(premiums)	6	5	14	1		
Approximation of interest in rental expense	4	3	4	0	4	4
Total Fixed Charges:	$ 608	$ 200	$ 259	$ 18	$ 297	$ 474
Ratio of Earnings to combined Fixed Charges	2.38	1.56	1.88	1.71	11.61	(5.17)

Exhibit 12.2

NRG Energy, Inc

Computation of Ratio of Earnings to Fixed Charges And Preferred Stock Dividend Requirements

	For the Year Ended December 2006	For the Year Ended December 2005	For the Year Ended December 2004	For the Period December 6, 2003 Through December 31, 2003	For the Period January 1, 2003 Through December 5, 2003	For the Year Ended December 2002
			(In millions except ratio)			
Earnings:						
Income/(loss) before taxes from continuing Operations before income tax	$ 880	$ 119	$ 229	$ 11	$ 3,192	$ (2,857)
Minority interest in earnings				—	—	—
Less:						
Undistributed equity in earning of unconsolidated affiliates	(33)	(8)	(1)	2	(41)	(22)
Capitalized interest	(5)	—	—	—	—	(46)
Preference dividends — tax effected	(83)	(33)	(1)			
Add:						
Fixed Charges	691	233	259	18	297	474
Total Earnings:	$ 1,450	$ 311	$ 486	$ 31	$ 3,448	$ (2,451)
Fixed Charges:						
Interest expense	$ 571	$ 186	$ 232	$ 16	$ 275	$ 397
Interest capitalized	5	—	—	—	—	46
Amortization of debt issuance costs	22	6	9	1	18	27
Amortization of debt discount/(premiums)	6	5	14	1	—	
Approximation of interest in rental expense	4	3	4	0	4	4
Tax effect of Preference dividends	83	33	1			
Total Fixed Charges:	$ 691	$ 233	$ 260	$ 18	$ 297	$ 474
Ratio of Earnings to combined Fixed Charges and Preference Dividends	2.10	1.33	1.87	1.71	11.61	(5.17)

Exhibit 21
NRG Energy, Inc. Subsidiaries

Subsidiary Name	State of Incorporation
Arthur Kill Power LLC	Delaware
Astoria Gas Turbine Power LLC	Delaware
Bayou Cove Peaking Power, LLC	Delaware
Berrians I Gas Turbine Power LLC	Delaware
Big Cajun I Peaking Power LLC	Delaware
Big Cajun II Unit 4 LLC	Delaware
Cabrillo Power I LLC	Delaware
Cabrillo Power II LLC	Delaware
Camas Power Boiler Limited Partnership	Oregon
Camas Power Boiler, Inc.	Oregon
Central and Eastern Europe Power Fund, Ltd.	Bermuda
Chickahominy River Energy Corp.	Virginia
Commonwealth Atlantic Power LLC	Delaware
Conemaugh Fuels, LLC	Delaware
Conemaugh Power LLC	Delaware
Connecticut Jet Power LLC	Delaware
Croatia Power Group	Cayman Islands
Devon Power LLC	Delaware
Dunkirk Power LLC	Delaware
Eastern Sierra Energy Company	California
Elbow Creek Wind Project LLC (Formed 2/5/07)	Texas
El Segundo Power II LLC	Delaware
El Segundo Power, LLC	Delaware
Energy Investors Fund, L.P.	Delaware
Energy National, Inc.	Utah

Subsidiary Name	State of Incorporation
Enfield Holdings B.V.	Netherlands
Enfield Operations, L.L.C.	Delaware
Enifund, Inc.	Utah
Enigen, Inc.	Utah
ESOCO Molokai, Inc.	Utah
ESOCO, Inc.	Utah
Fernwärme GmbH Hohenmölsen-Webau	Germany
GALA-MIBRAG-Service GmbH	Germany
GCP Funding Company, LLC	Delaware
Gladstone Power Station Joint Venture	Australia
Granite II Holding, LLC	Delaware
Granite Power Partners II, L.P.	Delaware
Gröbener Logistick GmbH — Spedition, Handel und Transport	Germany
Gunwale B.V.	Netherlands
Hanover Energy Company	California
Hoffman Summit Wind Project, LLC	California
Huntley IGCC LLC	Delaware
Huntley Power LLC	Delaware
Indian River IGCC LLC	Delaware
Indian River Operations Inc.	Delaware
Indian River Power LLC	Delaware
Ingenieurbüro für Grundwasser GmbH	Germany
Itiquira Energetica S.A.	Brazil
Jackson Valley Energy Partners, L.P.	California
James River Power LLC	Delaware
Kaufman Cogen LP	Delaware
Keystone Fuels, LLC	Delaware

Subsidiary Name	**State of Incorporation**
Keystone Power LLC	Delaware
Kladno Power (No. 1) B.V.	Netherlands
Kladno Power (No. 2) B.V.	Netherlands
Kraftwerk Schkopau Betriebsgesellschaft mbH	Germany
Kraftwerk Schkopau GbR	Germany
Lake Erie Properties Inc.	Delaware
Lambique Beheer B.V.	Netherlands
Long Beach Generation LLC	Delaware
Long Beach Peakers LLC (Formed 2/9/07)	Delaware
Long Beach Power LLC	Delaware
Louisiana Generating LLC	Delaware
LS Power Management, LLC	Delaware
LSP-Nelson Energy, LLC	Delaware
Meriden Gas Turbines LLC	Delaware
MIBRAG B.V.	Netherlands
MIBRAG Industriekraftwerke Betriebs GmbH	Germany
MIBRAG Industriekraftwerke GmbH & Co. KG	Germany
MIBRAG Industriekraftwerke Vermogensverwaltungs-und Beteiligungs GmbH	Germany
MIBRAG Industriekraftwerke Vertriebs GmbH	Germany
Middletown Power LLC	Delaware
Mitteldeutsche Braunkohlengesellschaft mbH	Germany
Montan Bildungs- und Entwicklungsgesellschaft mbH	Germany
Montville IGCC LLC	Delaware
Montville Power LLC	Delaware
MUEG Mitteldeutsche Umwelt- und Entsorgung GmbH	Germany
NEO California Power LLC (Terminated 1/3/07)	Delaware
NEO Chester-Gen LLC	Delaware
NEO Corporation	Minnesota
NEO Freehold-Gen LLC	Delaware

Subsidiary Name	State of Incorporation
NEO Landfill Gas Holdings Inc.	Delaware
NEO-Montauk Genco Management LLC	Delaware
NEO California Power LLC (Terminated 1/3/07)	Delaware
NEO Power Services Inc.	Delaware
New Genco GP, LLC	Delaware
New Genco LP, LLC	Delaware
Norwalk Power LLC	Delaware
NRG Affiliate Services Inc.	Delaware
NRG Arthur Kill Operations Inc.	Delaware
NRG Asia-Pacific, Ltd.	Delaware
NRG Astoria Gas Turbine Operations Inc.	Delaware
NRG Audrain Generating LLC	Delaware
NRG Audrain Holding LLC	Delaware
NRG Bayou Cove LLC	Delaware
NRG Bourbonnais Equipment LLC	Delaware
NRG Bourbonnais LLC	Illinois
NRG Brazos Valley GP LLC	Delaware
NRG Brazos Valley LP LLC	Delaware
NRG Cabrillo Power Operations Inc.	Delaware
NRG Cadillac Inc.	Delaware
NRG Cadillac Operations Inc.	Delaware
NRG California Peaker Operations LLC	Delaware
NRG Capital II LLC	Delaware
NRG Caymans Company	Cayman Islands
NRG Caymans-C	Cayman Islands
NRG Caymans-P	Cayman Islands
NRG Collinsville Operating Services Pty Ltd	Australia
NRG ComLease LLC	Delaware

Subsidiary Name	State of Incorporation
NRG Common Stock Finance I LLC	Delaware
NRG Common Stock Finance II LLC	Delaware
NRG Connecticut Affiliate Services Inc.	Delaware
NRG Development Company Inc.	Delaware
NRG Devon Operations Inc.	Delaware
NRG do Brasil Ltda.	Brazil
NRG Dunkirk Operations Inc.	Delaware
NRG El Segundo Operations Inc.	Delaware
NRG Energy Center Dover LLC	Delaware
NRG Energy Center Harrisburg LLC	Delaware
NRG Energy Center Minneapolis LLC	Delaware
NRG Energy Center Paxton LLC	Delaware
NRG Energy Center Pittsburgh LLC	Delaware
NRG Energy Center Rock Tenn LLC	Delaware
NRG Energy Center San Diego LLC	Delaware
NRG Energy Center San Francisco LLC	Delaware
NRG Energy Center Smyrna LLC	Delaware
NRG Energy Center Washco LLC	Delaware
NRG Energy Insurance, Ltd.	Cayman Islands
NRG Energy Jackson Valley I, Inc.	California
NRG Energy Jackson Valley II, Inc.	California
NRG Energy Ltd.	United Kingdom
NRG Energy, Inc.	Delaware
NRG Engine Services LLC	Delaware
NRG Generation Holdings, Inc.	Delaware
NRG Gladstone Operating Services Pty Ltd	Australia
NRG Gladstone Superannuation Pty Ltd	Australia

Subsidiary Name	State of Incorporation
NRG Granite Acquisition LLC	Delaware
NRG Harrisburg Cooling LLC (Formed 1/30/07)	Delaware
NRG Huntley Operations Inc.	Delaware
NRG Ilion Limited Partnership	Delaware
NRG Ilion LP LLC	Delaware
NRG International Holdings (No. 2) GmbH	Switzerland
NRG International II Inc.	Delaware
NRG International III Inc.	Delaware
NRG International LLC	Delaware
NRG Kaufman LLC	Delaware
NRG Latin America Inc.	Delaware
NRG Maintenance Services LLC	Delaware
NRG McClain LLC	Delaware
NRG Mesquite LLC	Delaware
NRG Mextrans Inc.	Delaware
NRG MidAtlantic Affiliate Services Inc.	Delaware
NRG Middletown Operations Inc.	Delaware
NRG Montville Operations Inc.	Delaware
NRG Nelson Turbines LLC	Delaware
NRG New Jersey Energy Sales LLC	Delaware
NRG New Roads Holdings LLC	Delaware
NRG North Central Operations Inc.	Delaware
NRG Northeast Affiliate Services Inc.	Delaware
NRG Norwalk Harbor Operations Inc.	Delaware
NRG Operating Services, Inc.	Delaware
NRG Oswego Harbor Power Operations Inc.	Delaware
NRG PacGen Inc.	Delaware
NRG Pacific Corporate Services Pty Ltd	Australia

Subsidiary Name	State of Incorporation
NRG Peaker Finance Company LLC	Delaware
NRG Power Marketing Inc.	Delaware
NRG Rockford Acquisition LLC	Delaware
NRG Rockford Equipment II LLC	Illinois
NRG Rockford Equipment LLC	Illinois
NRG Rockford II LLC	Illinois
NRG Rockford LLC	Illinois
NRG Rocky Road LLC	Delaware
NRG Saguaro Operations Inc.	Delaware
NRG Services Corporation	Delaware
NRG South Central Affiliate Services Inc.	Delaware
NRG South Central Generating LLC	Delaware
NRG South Central Operations Inc.	Delaware
NRG South Texas LP	Texas
NRG Sterlington Power LLC	Delaware
NRG Telogia Power LLC	Delaware
NRG Texas LLC	Delaware
NRG Texas LP	Texas
NRG Texas Maintenance Services LLC	Delaware
NRG Thermal LLC	Delaware
NRG Victoria I Pty Ltd	Australia
NRG Victoria II Pty Ltd	Australia
NRG Victoria III Pty Ltd	Australia
NRG West Coast LLC	Delaware
NRG Western Affiliate Services Inc.	Delaware
NRGenerating German Holdings GmbH	Switzerland
NRGenerating Holdings (No. 24) B.V.	Netherlands

Subsidiary Name	State of Incorporation
NRGenerating Holdings (No. 5) B.V.	Netherlands
NRGenerating Holdings GmbH	Switzerland
NRGenerating II (Gibraltar)	Gibraltar
NRGenerating International B.V.	Netherlands
NRGenerating Luxembourg (No. 1) S.a.r.l.	Luxembourg
NRGenerating Luxembourg (No. 2) S.a.r.l.	Luxembourg
O Brien Cogeneration, Inc. II	Delaware
ONSITE Energy, Inc.	Oregon
Oswego Harbor Power LLC	Delaware
P.T. Dayalistrik Pratama	Indonesia
Pacific Crockett Holdings, Inc.	Oregon
Pacific Generation Company	Oregon
Pacific Generation Holdings Company	Oregon
Pacific-Mt. Poso Corporation	Oregon
Padoma Wind Power, LLC	California
Project Finance Fund III, L.P.	Delaware
Pyro-Pacific Operating Company	California
RWE Umwelt Westsachsen GmbH	Germany
Saale Energie GmbH	Germany
Saale Energie Services GmbH	Germany
Sachsen Holding B.V.	Netherlands
Saguaro Power Company, a Limited Partnership	California
Saguaro Power LLC	Delaware
San Joaquin Valley Energy I, Inc.	California
San Joaquin Valley Energy IV, Inc.	California
San Joaquin Valley Energy Partners I, L.P	California
San Juan Mesa Wind Project II, LLC	Delaware

Subsidiary Name	State of Incorporation
Somerset Operations Inc.	Delaware
Somerset Power LLC	Delaware
Statoil Energy Power/Pennsylvania, Inc.	Pennsylvania
Sterling Luxembourg (No. 4) s.a.r.l.	Luxembourg
Sunshine State Power (No. 2) B.V.	Netherlands
Sunshine State Power B.V.	Netherlands
Tacoma Energy Recovery Company	Delaware
Telogia Power Inc.	Delaware
TermoRio S.A.	Brazil
Texas Genco Financing Corp.	Delaware
Texas Genco GP, LLC	Texas
Texas Genco Holdings, Inc.	Texas
Texas Genco LP, LLC	Delaware
Texas Genco Operating Services, LLC	Delaware
Texas Genco Services, LP	Texas
The PowerSmith Cogeneration Project, Limited Partnership	Delaware
Tosli Acquisition B.V.	Netherlands
Turners Falls Limited Partnership	Delaware
UEG Mitteldeutsche Umwelt-Entsorgung GmbH	Unknown
Vienna Operations Inc.	Delaware
Vienna Power LLC	Delaware
WCP (Generation) Holdings LLC	Delaware
West Coast Power LLC	Delaware

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
NRG Energy, Inc.:

We consent to the incorporation by reference in the Registration Statements (File Nos. 333-114007, and 333-135973) on Form S-8 and in the Registration Statements (File Nos. 333-130549, and 333-123677) on Form S-3 of NRG Energy, Inc. of our reports dated February 28, 2007, with respect to the consolidated balance sheets of NRG Energy, Inc. as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and comprehensive income/(loss), and cash flows, for each of the years in the three-year period ended December 31, 2006, and related financial statement schedule, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 and the effectiveness of internal control over financial reporting as of December 31, 2006, which reports appear in the December 31, 2006 annual report on Form 10-K of NRG Energy, Inc.

Our report refers to the Company's adoption of Emerging Issues Task Force No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry," and Statement of Financial Accounting Standards (SFAS) No. 123(R), "Share Based Payments," and related interpretations on January 1, 2006. Our report refers to the Company's adoption of the disclosure requirements of SFAS No. 158 "Employers' Accounting for Defined Benefit Pension and Other Requirement Plans - an amendment of FASB Statements No. 87, 88, 89, 106 and 132(R)" effective December 31, 2006

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2007

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EXHIBIT 31.1

CERTIFICATION

I, David W. Crane, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ David W. Crane

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

Date: February 28, 2007

EXHIBIT 31.2

CERTIFICATION

I, Robert C. Flexon, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ Robert C. Flexon

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

Date: February 28, 2007

EXHIBIT 31.3

CERTIFICATION

I, Carolyn J. Burke, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ Carolyn J. Burke

Carolyn J. Burke
Controller
(Principal Accounting Officer)

Date: February 28, 2007

EXHIBIT 32

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

In connection with the Annual Report of NRG Energy, Inc. on Form 10-K for the year ended December 31, 2006, as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

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

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

Date: February 28, 2007

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

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

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

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

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