NRG ENERGY, INC.
Form 10-K
February 28, 2008

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

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year ended December 31, 2007.

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, par value $0.01 per share

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

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 o No þ

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 þ No o

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Ruler 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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 $9,869,468,545 based on the closing sale price of $41.57 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 þ No o

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 25, 2008
Common Stock, par value $0.01 per share	236,442,274

Documents Incorporated by Reference:

Portions of the Proxy Statement for the 2008 Annual Meeting of Stockholders to be held on May 14, 2008

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Glossary of Terms

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

Acquisition	February 2, 2006 acquisition of Texas Genco LLC, now referred to as the Company s Texas region
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
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 announced in 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

COLA	Combined Construction and Operating License Application
CPUC	California Public Utilities Commission
DNREC	Delaware Department of Natural Resources and Environmental Control
DPUC	Department of Public Utility Control
EAF	Measures the percentage of maximum generation available over time as the fraction of net maximum generation that could be provided over a defined period of time after all types of outages and deratings, including seasonal deratings, are taken into account

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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
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
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
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
LFRM	Locational Forward Reserve Market

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LIBOR	London Inter-Bank Offer Rate
LMP	Locational Marginal Prices
MADEP	Massachusetts Department of Environmental Protection
Merit Order	A term used for the ranking of power stations in order of ascending marginal cost
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, 2007
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
NO_x	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

PMI	NRG Power Marketing, LLC, a wholly-owned subsidiary of NRG which procures transportation and fuel for the Company s generation facilities, sells the power from these facilities, and manages 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
Repowering	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
*Repowering*NRG	NRG s program designed to develop, finance, construct and operate new, highly efficient, environmentally responsible capacity over the next decade
RFP	Request for proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROIC	Return on invested capital
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
Schkopau	Kraftwerk Schkopau Betriebsgesellschaft mbH, an entity in which NRG has a 41.9% interest
SCR	Selective Catalytic Reduction

SEC	United States Securities and Exchange Commission
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*

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SFAS 123R	SFAS No. 123 (revised 2004), *Share-Based Payment*
SFAS 133	SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended*
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 157	SFAS No. 157, *Fair Value Measurement*
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)*
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*
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
Tonnes	Metric tonnes, which are units of mass or weight in the metric system each equal to 2,205 lbs and are the global measurement for GHG
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

VOC	Volatile Organic Carbon
WCP	WCP (Generation) Holdings, Inc.

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PART I

Item 1 *Business*

General

NRG Energy, Inc., or NRG or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets. As of December 31, 2007, NRG had a total global portfolio of 191 active operating generation units at 49 power generation plants, with an aggregate generation capacity of approximately 24,115 MW, and approximately 740 MW under construction which includes partners interests. Within the United States, NRG has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,880 MW of generation capacity in 175 active generating units at 43 plants. These power generation facilities are primarily located in Texas (approximately 10,805 MW), the Northeast (approximately 6,980 MW), South Central (approximately 2,850 MW), and West (approximately 2,130 MW) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets. NRG s principal domestic power plants consist of a mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 46%, 33%, 16% and 5% of the Company s total domestic generation capacity, respectively. In addition, 15% of NRG s domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option. NRG s domestic generation facilities consist of baseload, intermediate and peaking power generation facilities, the ranking of which is referred to as Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s 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.

NRG s Major Initiatives

The Company s strategy is reflected in its five major initiatives, four of which were announced and began implementation in 2006. The fifth, Focus on ROIC @NRG , or *FOR*NRG, successfully concluded its third year in 2007. NRG s five major initiatives, described below, are designed to enhance the Company s competitive advantages of the opportunities and surmount the challenges faced by the power industry.

I. ***FOR*NRG** is a companywide effort, introduced in 2005, and is designed to increase the return on invested capital, or ROIC, through operational performance improvements to the Company s asset fleet, along with a range of initiatives at plants and at corporate offices to reduce costs or, in some cases, generate revenue. The *FOR*NRG earnings accomplishments disclosed in NRG s SEC filings and press releases include both recurring and one time improvements measured from a 2004 baseline, with the exception of the Texas region where benefits are measured using 2005 as the base year. For plant operations, the program measures cumulative current year benefits using current gross margins times the change in baseline levels of certain key performance indicators. The plant performance benefits include both positive and negative results for plant reliability, capacity, heat rate and station service. *FOR*NRG contributed $39 million to pre-tax earnings in 2005 and $144 million were achieved through the end of 2006. For 2007, the Company attained its previously announced target of $220 million which includes $11 million of one-time benefits.

II. ***Repowering*****NRG** is a comprehensive portfolio redevelopment program designed to develop, construct and operate new multi-fuel, multi-technology, highly efficient and environmentally responsible generation capacity over the next decade. Through this initiative, the Company anticipates retiring certain existing units and adding new generation to meet growing demand in the Company s core markets, with an emphasis on new baseload capacity that is expected to be supported by long-term power purchase agreements, or PPAs, and financed with limited or non-recourse project financing.

lII. **econrg** represents NRG s commitment to environmentally responsible power generation. econrg seeks to find ways to meet the challenges of climate change, clean air and water, and protecting our natural resources while taking advantage of business opportunities. This initiative builds upon its foundation in environmental compliance and embraces environmental initiatives for the benefit of our communities, employees and shareholders, such as encouraging investment in new environmental technologies, pursuing activities that preserve and protect the environment and encouraging changes in the daily lives of our employees.

IV. **Future NRG** is the Company s workforce planning and development initiative and represents NRG s strong commitment to planning for future staffing requirements to meet the on-going needs of the Company s current operations in addition to the Company s *Repowering*NRG initiatives. Future NRG encompasses analyzing the demographics, skill set and size of the Company s workforce in addition to the organizational structure with a focus on succession planning requirements, training, development, staffing and recruiting needs. Included under the Future NRG umbrella is NRG University, which develops leadership, managerial, supervisory and technical training programs and includes individual skill development courses.

V. **NRG Global Giving** - Respect for the community is one of NRG s core values. NRG s Global Giving Program invests the Company s resources to strengthen the communities where NRG does business and seeks to make investments in four focus areas: community and economic development, education, environment and human welfare.

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 principles:

Increase value from existing assets NRG has a highly diversified portfolio of power generation assets in terms of region, fuel-type and dispatch levels. Through the *FOR*NRG initiative, 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 improving the Company s ROIC.

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 (i) expertise in marketing power and ancillary services, (ii) its knowledge of markets, (iii) its balanced financial structure and (iv) its diverse portfolio of power generation assets.

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. Through the *Repowering*NRG initiative, NRG will continue 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 regional general portfolio; increased technological and fuel diversity; and reduced environmental impacts, including facilities that either have near zero greenhouse gas, or GHG, emissions or can be equipped to capture and sequester GHG emissions.

Reduce carbon intensity of portfolio while taking advantage of carbon-driven business opportunities NRG continues to actively pursue investments in new generating facilities and technologies that will be highly efficient and will employ no and low carbon technologies to limit CO_2 emissions and other air emission. Through the *Repowering*NRG and econrg initiatives, NRG is focused on the development of low or no GHG emitting energy generating sources, such as nuclear, wind, clean coal and gas, and the employment of post-combustion capture technologies, which represent significant commercial opportunities.

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, the Company s ongoing capital allocation objective includes scheduled repayment of debt based on the amount of cash flow by the Company each year, as well as an annual return of capital to shareholders, targeted at an average rate of 3% of market capitalization, of approximately $250 million to $300 million per year.

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 markets. 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 ownership of multiple plants in various 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 with 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 22,880 MW of generation capacity in 175 active generating units at 43 plants as of December 31, 2007. 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 8,700 MW of generation capacity measured as of December 31, 2007, provide the Company with a significant source of stable cash flow, while its intermediate and peaking facilities, with approximately 14,180 MW of generation capacity as of December 31, 2007, 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.

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The following chart demonstrates the diversification of NRG s domestic power generation assets as of December 31, 2007:

Reliability of future cash flows NRG has sold forward or otherwise hedged a significant portion of its expected baseload generation capacity through 2013. 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, 2007, the Company had purchased forward under fixed price contracts (with contractually-specified price escalators) to provide fuel for approximately 59% of its expected baseload coal generation output from 2008 to 2013. The hedge percentage is reflective of the current agreement of the Jewett mine in which NRG has the contractual ability to adjust volumes in future years. 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 cost dynamics for baseload power plants In 2007, approximately 87% of the Company s domestic generation output was from plants 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 the baseload assets in ERCOT 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 particular 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 by 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 also are often ideally situated for repowering or the addition of new capacity, because their location and existing infrastructure give them significant advantages over newly developed sites in their regions.

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Performance Metrics

The following table contains a summary of NRG s operating revenues by segment for the year ended December 31, 2007 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	Other Revenues	Total Operating Revenues
				(In millions)			
Texas	$ 2,698	$ 363	$ (33)	$ 219	$	$ 40	$ 3,287
Northeast	1,104	402	27			72	1,605
South Central	404	221	10	23			658
West	4	122				1	127
International	42	83				15	140
Thermal	13	5			125	16	159
Corporate/Eliminations						13	13
Total	$ 4,265	$ 1,196	$ 4	$ 242	$ 125	$ 157	$ 5,989

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: Measures the percentage of maximum generation available over time as the fraction of net maximum generation that could be provided over a defined period of time after all types of outages and deratings, including seasonal deratings, are taken into account.

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 required 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, 2007 and 2006:

	Year Ended December 31, 2007				
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	10,805	47,779	87.6%	10,300	50.7%
Northeast[(a)]	6,980	14,163	83.6	10,900	21.2
South Central	2,850	10,930	89.0	10,200	46.1
West	2,130	1,246	89.9%	11,200	9.3%

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Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/kWh	Net Capacity Factor
		Year Ended December 31, 2006 (In thousands of MWh)			
Texas[b]	10,760	44,910	91.0%	10,300	41.0%
Northeast[a]	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%

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

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

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

Employees

As of December 31, 2007, NRG had 3,412 employees, approximately 1,639 of whom were covered by U.S. bargaining agreements. During 2007, the Company did not experience any labor stoppages or labor disputes at any of its facilities.

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:

(1) Includes 115 MW as part of NRG s Thermal assets. For combined scale, approximately 3,450 MW is dual-fuel capable. Reflects only domestic generation capacity as of December 31, 2007.

As of December 31, 2007, the Company s power generation assets consisted of approximately 10,490 MW of gas-fired; 7,525 MW of coal-fired; 3,690 MW of oil-fired and 1,175 MW of nuclear generating capacity in the United States. In addition, NRG also owns approximately 115 MW of thermal capacity domestically 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 38% baseload, 37% intermediate and 25% 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 and average natural gas prices resulting from baseload hedge agreements extending beyond December 31, 2007 and through 2013:

	2008	2009	2010	2011	2012	2013	Annual Average for 2008-2013
			(In millions unless otherwise stated)				
Net Baseload Capacity (MW)	8,685	8,685	8,523	8,443	8,416	8,416	8,528
Forecasted Baseload Capacity (MW)	7,497	7,387	7,335	7,241	7,331	7,309	7,350
Total Baseload Sales (MW)[(a)]	7,390	5,416	4,066	4,206	1,543	1,005	3,938
Percentage Baseload Capacity Sold Forward[(b)]	99%	73%	55%	58%	21%	14%	54%
Total Forward Hedged Revenues[(c)(d)]	$ 3,701	$ 2,735	$ 2,000	$ 1,959	$ 644	$ 392	$ 1,905
Weighted Average Hedged Price ($ per MWh)[(c)]	$ 57	$ 58	$ 56	$ 53	$ 47	$ 45	$ 53
Weighted Average Hedged Price ($ per MWh) excluding South Central region[(d)]	$ 60	$ 61	$ 60	$ 56	$ 54	$	$ 58
Average Equivalent Natural Gas Price ($ per MMBtu)[(e)]	$ 7.30	$ 7.43	$ 7.27	$ 6.84	$ 6.33	$ 6.10	$ 6.88
Average Equivalent Natural Gas Price ($ per MMBtu) excluding South Central region[(e)]	$ 7.50	$ 7.70	$ 7.49	$ 7.03	$ 6.70	$	$ 6.07

(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, 2007 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 natural 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 $40/MWh $45/MWh due to legacy cooperative load contracts entered into at prices significantly below current market levels. These prices include a fixed capacity charge and an estimated energy charge.

(e) The weighted average hedged price in natural gas equivalents is derived by first multiplying the quantity of MWh of power hedged by the forward market implied heat rate as of December 31, 2007 to arrive at the equivalent MMBtu hedged which is then added with the financially hedged gas quantity. This total quantity in MMBtu is then used to divide the total revenues from all baseload sales to arrive at the weighted average hedged price in natural gas equivalents.

The following is a discussion of NRG s generation assets by segment for the year ended December 31, 2007.

Texas Region As of December 31, 2007, NRG s generation assets in the Texas region consisted of approximately 5,325 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 South Texas Project, or STP, which uses nuclear fuel. Power plants are generally dispatched in order of lowest operating cost and as of December 31, 2007, 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 when available, subject to planned and forced outages.

Northeast Region As of December 31, 2007, NRG generation assets in the Northeast region of the United States consisted of approximately 6,980 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, 2007, NRG s generation assets in the Northeast region consisted of approximately 1,870 MW of baseload generation assets and approximately 5,110 MW of intermediate and peaking assets.

South Central Region As of December 31, 2007, NRG generation assets in the South Central region of the United States consisted of approximately 2,405 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. A significant portion of the region s generation capacity has been sold to eleven cooperatives within the region through 2025. In addition, the region also operates 445 MW of peaking generation in Rockford, Illinois under the PJM region.

West Region As of December 31, 2007, NRG generation assets in the West region of the United States consisted of approximately 2,130 MW. 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. On August 1, 2007, the Company successfully completed and commissioned the repowering of 260 MW of new gas-fired generating capacity at its Long Beach Generating Station.

International Region As of December 31, 2007, 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 owns equity interests in certain coal mines in Germany. On December 18, 2007, NRG entered into a sale and purchase agreement to sell its 100% interest in Tosli Acquisition B.V., which holds all of NRG s interest in ITISA, to Brookfield Asset Management Inc. for the purchase price of $288 million, plus the assumption of approximately $60 million in debt. NRG anticipates the completion of the sale transaction during the first half 2008.

Thermal NRG owns thermal and chilled water businesses that generate approximately 1,040 MW thermal equivalents. In addition, NRG s thermal segment owns certain power plants with approximately 116 MW of power generating capacity located in Delaware and in Pennsylvania.

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. In addition, because changes in power prices in the markets where NRG operates are generally correlated to changes in natural gas prices, the Company hedges a portion of its generation portfolio power using natural gas swaps and other financial instruments.

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 are 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, and is based on forecasted generation and market volatility. As of December 31, 2007, NRG had purchased forward contracts to provide fuel for approximately 59% of the Company s requirement from 2008 through 2013. 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 38 million tons of coal in 2007, and is one of the largest coal purchasers in the United States.

The following table shows the percentage of the Company s coal and lignite requirements from 2008 through 2013 that have been purchased forward:

	Percentage of Company s Requirement[(1)]
2008	99%
2009	86%
2010	58%
2011	52%
2012	45%
2013	15%

(1) The hedge percentages reflect the current plan for the Jewett mine. NRG has the contractual ability to change volumes and may do so in the future.

As of December 31, 2007, NRG had approximately 7,600 privately leased or owned rail cars in the Company s transportation 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 primarily comprised of 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 natural gas on units that may not run. The Company contracts for natural gas storage services as well as natural gas transportation services to ensure delivery of natural gas when needed.

Nuclear Fuel STP s owners satisfy STP s fuel supply requirements by (i) acquiring uranium concentrates and contracting for conversion of the uranium concentrates into uranium hexafluoride, (ii) contracting for enrichment of uranium hexafluoride and (iii) 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 at its

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highest in the Company s 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.

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 maximize results for the Company. NRG sets performance goals for equivalent forced outage rates, or EFOR, availability, procurement costs, operating costs, safety and environmental compliance.

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

To support *Repowering*NRG initiatives, the Company has organized its project execution process into one centralized group consisting of engineering, procurement and construction, or EPC. This group combines regional engineering functions with corporate project engineering, project management, procurement and construction functions to provide a consistent and standardized execution of the repowering initiative. 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.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2008 through 2012 to meet NRG s environmental commitments will be between $1.0 billion and $1.4 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with Clean Air Interstate Rule, or CAIR, the Clean Air Mercury Rule, or CAMR, and related state requirements as well as installation of Best Technology Available under the Phase II 316(b) rule. NRG continues to explore cost effective alternatives that can achieve desired results. The range reflects alternative strategies available with respect to the Company s Indian River plant.

The following table summarizes the upper end of the estimated range for major environmental capital expenditures for the referenced periods by region:

	Texas	Northeast	South Central	Total
			(In millions)	
2008	$ 3	$ 223	$ 133	$ 359
2009	5	192	211	408
2010	24	178	117	319
2011	28	112	53	193
2012	11	66	15	92

Total	$ 71	$ 771	$ 529	$ 1,371

NRG plans to reduce the impact of a portion of the above environmental capital expenditures. NRG has the ability to monetize a portion of the Company s excess allowances over the 2008 through 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 capital 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.

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Carbon Update

There is a growing consensus in the U.S. and globally that GHG emissions are a major cause of global warming. At the national level and at various regional and state levels, policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentive to reduce them. In addition, earlier this year, the U.S. Supreme Court found that CO_2, the most common GHG, could be regulated as a pollutant and that the USEPA should regulate CO_2 emissions from mobile sources. Since power plants, particularly coal-fired plants, are a significant source of GHG emissions both in the United States and globally, it is almost certain that GHG regulatory actions will encompass power plants as well as other GHG emitting stationary sources. In 2007, in the course of producing approximately 80 million MWh of electricity, NRG s power plants emitted 68 million tonnes of CO_2, of which 61 million tonnes were emitted in the United States, 3 million tonnes in Australia and 4 million tonnes in Germany.

Federal, state or regional regulation of GHG emissions could have a material impact on the Company s financial performance. The actual impact on the Company s financial performance will depend on a number of factors, including the overall level of GHG reductions required under any such regulations, the price and availability of offsets, and the extent to which NRG would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market. For example, the U.S. Senate is currently considering climate change legislation sponsored by Senators Lieberman and Warner. If legislation with the same level of allocations to existing generation resources and emissions reductions as those contained in the current version of the Lieberman-Warner legislation were enacted, NRG expects that the legislation will have a minimal impact on the Company s financial performance through the next decade. Thereafter, under such legislation, the impact on NRG would depend on the Company s level of success in developing and deploying low and no carbon technologies being pursued as part of our *Repowering*NRG and econrg initiatives. Additionally, NRG s current contracts with its South Central region s cooperative customers allows for the recovery of emission-based costs.

State and regional initiatives such as the Regional Greenhouse Gas Initiative, or RGGI, in the Northeast, and the Western Climate Initiative, or WCI, are developing market-based programs to counteract climate change. The RGGI states are in the process of promulgating state regulations needed for implementation with six of the ten states issuing drafts for comment. With state legislation and regulation in place, the first regional auction of RGGI allowances needed by power generators could be held as early as the summer of 2008. WCI is in the formative stages of the regional effort. California has enacted Assembly Bill 32 California Global Warming Solutions Act of 2006, or AB32, which requires the California Air Resources Board to develop a GHG reduction program to reduce emissions to 1990 levels by 2020, a reduction of approximately 25%. This reduction program will be phased in beginning 2012 pursuant to regulations to be adopted by 2011.

NRG does not expect that implementation of AB32 in California will have a significant adverse financial impact on the Company for a variety of reasons, including the fact that NRG s California portfolio consists of natural gas-fired peaking facilities and will likely be able to pass through any costs of purchasing allowances in power prices. However, of the approximately 61 million tonnes of CO_2 emitted by NRG in the United States in 2007, approximately 12 million tonnes were emitted from the Company s generating units in Connecticut, Delaware, Maryland, Massachusetts and New York that will likely be subject to RGGI in 2009. The impact of RGGI on power prices (and thus on the Company s financial performance), indirectly through generators seeking to pass through the cost of their CO_2 emissions, cannot be predicted. However, NRG believes that due to the absence of any significant allowance allocations under RGGI, the direct financial impact on NRG is likely to be negative as the Company will incur costs in the course of securing the necessary allowances and offsets at auction and in the market.

In this regard, the Company has a multifold strategy with respect to climate change and related GHG regulation. First, the Company is seeking to influence public policy as it emerges at various levels of government in order to ensure that such legislation is fair and effective in reducing GHG emissions. To ensure such effectiveness, NRG believes it is particularly important that legislation be supportive of the research, development, demonstration and deployment of low and no carbon power generation technologies. The Company is carrying out its efforts to influence public policy on its own and as part of two collective efforts. In July 2007, NRG joined the United States Climate Action Partnership, or USCAP, an alliance of major businesses and leading climate and environmental groups which are calling for federal legislation requiring significant reductions of GHG emissions. Also in January 2007, the Company joined with 46 other global business leaders to support a new initiative, Combating Climate Change, or 3C. This initiative calls for the global business community to take a leadership role in designing the road map to a low carbon society.

Second, the Company is actively pursuing investments in new generating facilities and technologies that will be highly efficient and will employ no and low carbon technologies to limit CO_2 emissions and other air emissions through its *Repowering*NRG program. The Company anticipates that these investments will result in long-term GHG intensity reductions in its generating portfolio. The most notable of these projects in terms of the potential impact on the GHG intensity of the Company s portfolio is the 2,700 MW (gross) STP units 3 and 4 nuclear project in Texas. In addition to the nuclear development project, the Company has other low and no GHG emitting wind, clean coal and gas projects under active development. The extent to which these projects, and our remaining coal projects under development, impact our overall carbon exposure will depend on our ability to complete development of these projects, the nature and geographic reach of any GHG regulation which goes into effect and the extent to which the carbon risk associated with our development projects are allocated between the Company and any offtakers under power purchase agreements or similar arrangements.

Third, the Company is seeking to demonstrate through its econrg program the large scale viability of post-combustion carbon capture technologies. For example, NRG is working with Powerspan Corp, or Powerspan, to deploy a scaled up demonstration of their ammonium-based ECO_2^{tm} carbon capture technology at the Company s W.A. Parish facility in Texas. The captured CO_2 would be either sequestered or used in enhanced oil recovery operations. The Company believes that there may be significant commercial opportunity in participating in such a project.

Fourth, the Company is preparing for the commercial operations activities which will be required as part of any climate change regulatory scheme that is implemented. In May 2007, the Company joined the Chicago Climate Exchange, a GHG emissions reduction, registry and trading system, as part of the Company s ongoing program to increase its climate change awareness, track its CO_2 emissions and address climate change proactively.

Fifth, and finally, the Company has for the past year, and will going forward, factor into its capital investment decision making process assumptions regarding the costs of complying with anticipated GHG regulations. As a result, all decisions with respect to acquisitions, repowerings, project development and further investment in our existing facilities will be made on the assumption that there will be a cost associated with GHG emissions in the future.

FORNRG Update

For 2007, NRG attained its previously announced target of $220 million which includes $11 million of one-time benefits. The 2007 results were largely driven by corporate initiatives and improved performance of the generating fleet particularly in the area of generating capacity, heat rate and station service. During 2007, the Company announced the acceleration and planned conclusion of the *FOR*NRG 1.0 program by bringing forward the previously announced 2009 target of $250 million in pre tax income improvements to 2008. During 2008, the Company will launch the next phase of the program under the banner *FOR*NRG 2.0.

RepoweringNRG Update

In 2006, NRG announced a comprehensive portfolio redevelopment program, referred to as *Repowering*NRG, which involves the development, 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 this initiative, the Company anticipates retiring certain existing units and adding new generation, with an emphasis on new baseload capacity that is expected to be supported by long-term power purchase agreements, or PPAs, and financed with limited or non-recourse project financing. NRG continues to expect 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 anticipates 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.

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A critical aspect of the *Repowering*NRG program is the extent to which the Company is actively pursuing investments in new generating facilities that will be highly efficient and will employ no and/or low carbon technologies to limit CO_2 emissions and other air emissions. The Company anticipates that these investments will result in long-term GHG intensity reductions in its generating portfolio.

Although NRG believes it is unlikely that the program will be fully implemented as originally proposed, the Company expects that the overall capital expenditures in connection with the program will be substantial. The Company plans to mitigate the capital cost of the program through equity partnerships and public-private partnerships, as well as through the reimbursement of development fees for certain projects. To further mitigate the investment risks, NRG anticipates entering into long-term PPAs and engineering, procurement and construction, or EPC, contracts. In addition, 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, 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 also 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 is a summary of repowering projects that have either been completed and are operating, under construction or in certain stages of development. In addition, NRG continues to participate in active bids in response to requests for proposals in markets in which it operates, particularly in the West and Northeast regions.

Plants Completed and Operating

Long Beach On August 1, 2007, the Company successfully completed and commissioned the repowering of 260 MW of new gas-fired generating capacity at its Long Beach Generating Station. This new generation will provide needed support for the summer peak demand to Southern California Edison, or SCE, and California Independent System Operator, or CAISO. This project is backed by a 10-year PPA executed with SCE in November 2006. The total incremental capital cost for the project was approximately $78 million.

Plants under Construction

Cedar Bayou Generating Station In August 2007, NRG Cedar Bayou Development Company LLC, or NRG Cedar Bayou, a subsidiary of NRG Energy, Inc., and EnergyCo Cedar Bayou 4, LLC, or EnergyCo Cedar Bayou, a subsidiary of EnergyCo, LLC, which is a joint venture between PNM Resources Inc. and a subsidiary of Cascade Investment, LLC, agreed to jointly develop, construct, operate and own, on a 50/50 undivided interest basis, a new 550 MW combined cycle natural gas turbine generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas.

NRG will also provide various ongoing services related to construction management, plant operations and maintenance, and use of existing NRG facilities in return for a fixed fee plus reimbursement of the Company s costs.

On July 26, 2007, the Texas Commission on Environmental Air Quality, or TCEQ, granted an air permit required for construction and operation of the new plant, and on August 1, 2007, NRG Cedar Bayou and EnergyCo Cedar Bayou entered into an EPC agreement with Zachry Construction Corporation to construct the plant which is expected to be completed in 2009.

Sherbino Wind Farm On February 1, 2008, NRG, through its wholly owned subsidiary, Padoma Wind Power LLC., entered into a fifty percent partnership with BP Alternative Energy North America Inc. to build the first phase of the Sherbino Wind Farm, a 150 MW wind project. The Sherbino I Wind Farm will be located on a more than 9,000 acre mesa with an elevation of approximately 3,000 feet above sea level, approximately 40 miles east of Fort Stockton in Pecos County, Texas. Initial construction of the Sherbino I Wind Farm commenced in November 2007 and will utilize 50 Vestas V90 3 MW wind turbine generators. The project is scheduled to reach commercial operations by the end of 2008 with NRG s 50 percent ownership providing a net capacity of 75 MW or the equivalent of 25 generators.

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Cos Cob The Company continues to proceed with the repowering project at its Cos Cob site in Connecticut, with the construction of 40 MW of peaking capacity following the receipt of the siting and air permits. The Company anticipates completion and commissioning of the unit in the summer of 2008.

Plants under Development

STP Units 3 and 4 On November 30, 2007, the Nuclear Regulatory Commission, or NRC, accepted the Company s Combined Construction and Operating License Application, or COLA, which was filed September 24, 2007, together with San Antonio s CPS Energy and South Texas Project Nuclear Operating Company, or STPNOC, to build and operate two new nuclear units at the STP nuclear power station site. The total rated capacity of the new units, STP units 3 and 4, will equal or exceed 2,700 MW. The acceptance review confirms that the application, the first to be filed with the NRC in 29 years, is technically complete and sufficiently addresses all necessary subject areas. With the COLA accepted or docketed, the NRC begins a comprehensive and detailed review process that includes requests for additional information, site visits, responses from NRG, public hearings, NRC Environmental Impact Statements and NRC Safety Evaluation Reports. The Company expects to achieve commercial operation for Unit 3 approximately 48 months after issuance of the COLA, and commercial operation for Units 4 approximately 12 months thereafter.

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

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

Huntley IGCC In December 2006, NRG won a conditional award of a power purchase agreement in support of the construction of a 600MW IGCC plant in a competitive bid process with the New York Power Authority, or NYPA. This plant would be built at the Company s existing 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 which the State of New York subsequently required as part of the overall award.

Since the announcement of the conditional award, NRG has worked with Mitsubishi Heavy Industries, or MHI, as a technology provider for this project. To date the initial engineering, or feasibility study has been completed for the project. The next phase includes front-end engineering design, or FEED. During this phase, NRG will determine specific design requirements and costing for the project, including CO_2 capture. At the same time, NRG and MHI would negotiate the form of an EPC agreement. NRG has also completed its detailed geological assessment of target sequestration sites which indicates that no fatal flaws exist for the long term injection and storage of the captured CO_2. NRG is working with the State of New York to build the legal and regulatory infrastructure for the injection of the CO_2 and the future responsibility for sequestered carbon.

With respect to the price gap closure initiative, the Company has identified existing local and state incentives and programs that can effectively close the price gap. It has submitted these initiatives to the State, where analysis against the State s budget has begun. NRG expects the State to formally respond to the price gap analysis during the first half of 2008. Any remaining price gaps will need to be closed through federal initiatives and the Company has a federal outreach effort in place to address these initiatives in Washington D.C.

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The next significant phase of this project, particularly the FEED work, will require monthly spending at a level that could not be a supported without the State formally approving the award. NRG is working with NYPA and the Governor s staff to secure this award before moving to the next phase of the project.

Big Cajun I NRG is continuing its development efforts to repower the Big Cajun I site with a 207 net MW circulating fluidized bed boiler, or CFB. NRG has signed a memorandum of understanding with potential co-owners for approximately 50% of the plants capacity and has also signed term sheets for long-term PPAs for the remaining 50%. In January 2008, the Company received the Title V air permit for the project from the Louisiana Department of Environmental Quality, or LDEQ, however in February 2008, certain environmental advocacy groups initiated a state court proceeding to challenge of the LDEQ s decision to issue the air permit and stay the effectiveness of the air permit. NRG believes that claims of the environmental advocacy groups are without merit, and NRG plans to intervene in the state court proceedings. Subject to the favorable resolution of the state court proceedings, the project timeline anticipates an engineering and construction start date in late 2008.

Connecticut Peakers In 2007, the Connecticut legislature passed a law that required state utilities, and permitted others, to submit plans for new peaking generation facilities in Connecticut subject to a regulated long-term contract. In the fall of 2007, NRG and United Illuminating Company, or UI, a wholly-owned subsidiary of UIL Holding Corporation, announced a joint venture to respond to this procurement process. NRG and UI subsequently formed GenConn Energy LLC as their joint venture vehicle and submitted a joint qualification package, as required, on February 1, 2008 with the Department of Public Utility Control, or DPUC. UI and NRG are evaluating the optimal combination of project size and locations that might be offered into their proposal. Binding bids are due March 3, 2008, with a final decision anticipated by June 2008.

econrg Update

econrg is a complementary program to *Repowering*NRG. econrg seeks to reduce the Company s carbon intensity through the implementation of low and no carbon repowering projects and through the investment in and demonstration of carbon capture and other environmentally advanced technologies. econrg is also focused on increasing environmental awareness, the advocacy of sound environmental policy and reducing the environmental footprint of the Company, its assets and its employees. The following is a summary of the Company s econrg projects.

Commercial Scale Carbon Capture and Sequestration Demonstration

On November 2, 2007, NRG signed a memorandum of understanding with Powerspan Corp., or Powerspan, to jointly design, construct, and operate a demonstration facility that will be among the largest carbon capture and sequestration projects in the world and may be the first to achieve commercial scale from an existing coal-fueled power plant. The project will be constructed at NRG s W.A. Parish plant near Sugar Land, Texas, and is designed to capture and sequester up to 90% of the carbon dioxide from flue gas equal in quantity to that from a 125 MW unit using Powerspan s proprietary ECO$_2^{tm}$ technology, a post-combustion, regenerative process which uses an ammonia-based solution to capture CO_2 from the flue gas and release it in a form that is ready for safe transportation and permanent geological storage. The CO_2 from the process would either be sequestered or sold for use in enhanced oil recovery projects. The project, which is expected to be operational in 2012, will be funded by NRG, potential partners and federal and state grants.

Plasma Gasification Technology

On April 3, 2007, NRG purchased approximately 2.2 million shares at CAD$2.25 per share for a 6% interest in Alter Nrg Corporation, a Canadian company that provides alternative energy solutions using plasma gasification, a process that converts carbon-containing materials into synthetic gas. As part of the transaction NRG has been granted an exclusive license to use Alter Nrg Corporation s plasma torch technology to (i) gasify fossil fuel and biomass in power projects in the United States, and (ii) develop other gasification projects in the vicinity of existing NRG plants. In January 2008, the Company received a qualified approval from the Massachusetts Department of Environmental Protection to convert the Somerset, MA facility to a coal and biomass gasification power facility.

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Regional Business Descriptions

NRG is organized into business units, with each of the Company s core regions operating as a separate business segment as discussed below.

TEXAS

NRG s largest business segment 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 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 (i) ensure the availability of the baseload plants to fulfill their commercial obligations under long-term forward sales contracts already in place, (ii) manage the natural gas assets for profitability while ensuring the reliability and flexibility of power supply to the Houston market, (iii) 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 (iv) 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 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 and to provide upside for expanding heat rates. For the gas-fired capacity sold forward, the Company will offer a range of products tailored to our customers 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 economical to run.

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

	Net Generation		
	2007	2006	2005
	(In thousands of MWh)		
Coal	32,648	31,371	31,299
Gas	5,407	7,983	6,806
Nuclear[a]	9,724	9,385	6,412
Total	47,779	48,739	44,517

(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%.

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Generation Facilities

As of December 31, 2007, NRG s generation facilities in Texas consisted of approximately 10,805 MW of generation capacity. The following table describes NRG s electric power generation plants and generation capacity as of December 31, 2007:

Plant	Location	% Owned	Net Generation Capacity (MW)[c]	Primary Fuel-type
Solid Fuel Baseload Units:				
W. A. Parish[a]	Thompsons, TX	100.0	2,460	Coal
Limestone	Jewett, TX	100.0	1,690	Lignite/Coal
South Texas Project[b]	Bay City, TX	44.0	1,175	Nuclear
Total Solid Fuel Baseload			5,325	
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[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			**10,805**	

(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 at 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 2,200 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 2,460 MW as of December 31, 2007. Two of these units are 645/650 MW steam units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 565 MW and 600 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 Selective Catalytic Reductions, or SCRs, 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.

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 1,690 MW as of December 31, 2007. The first unit is an 830 MW steam unit that was placed in commercial service in December 1985. The second unit is an 860 MW steam unit that was placed in commercial service in December 1986. Limestone burns lignite from an adjacent 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. Both units have installed low-NO_x burners to reduce NO_x emissions and scrubbers to reduce SO_2 emissions.

NRG owns the mining equipment and facilities and a portion of the lignite reserves located at the adjacent mine. Mining operations are conducted by Texas Westmoreland Coal Co., a single purpose, wholly-owned

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subsidiary of Westmoreland Coal Company and the owner of a substantial portion of the remaining lignite reserves. The contract, entered into August 1999, ended December 31, 2007. Effective January 1, 2008, NRG entered into an agreement with Texas Westmoreland Coal Co. to continue to supply lignite from the same surface mine adjacent to the facility for a nominal term of ten years with an option for future year supply purchases. This is a cost-plus arrangement under which NRG will pay all of Westmoreland s agreed upon production costs, capital expenditures, and a per ton mark up. The annual volume demand is determined by NRG. The agreement ensures lignite supply to NRG and confirms NRG s responsibility for the final reclamation at the mine.

South Texas Project Electric Generating Station 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 1,335 MW of generation capacity. STP s two generation units commenced operations in August 1988 and June 1989, respectively. For the year ended December 31, 2007, 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%, or approximately 1,175 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 most significant commercial as well as asset investment decisions for the existing units 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.

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. For the past ten years, peak hourly demand in the ERCOT market grew at a compound annual rate of 2.5%, compared to a compound annual rate of growth of 2.1% in the United States for the same period. For 2007, hourly demand ranged from a low of 21,790 MW to a high of 62,188 MW. ERCOT has limited interconnections compared to other markets in the United States currently limited to 1,106 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 accesses the ERCOT electric power grid is allowed to sell power in the ERCOT market at unregulated rates.

The ERCOT market experienced significant construction of new generation plants, with over 29,000 MW of new generation capacity added to the market since 1996. As of December 31, 2007, aggregate net generation capacity of approximately 76,800 MW existed in the ERCOT market, of which 71.7% was natural gas-fired. Approximately 20,600 MW, or 26.9%, was lower marginal cost generation capacity such as coal, lignite and nuclear plants. NRG s coal and nuclear fuel baseload plants represent approximately 5,325 MW gross, or 25.9%, 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 for 2007 was 14.6% forecast to drop to 13.1% 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 ERCOT projects reserve margins to decrease in

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2009 primarily due to load growth. Several new projects have been announced or are under construction for 2010 and beyond, and there are currently plans being considered by the PUCT to build a significant amount of transmission from west Texas and continuing across the state to enable wind generation to reach load. The ultimate impact on the reserve margin and wholesale dynamics from these plans are unknown.

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, STP, and all its natural gas-fired plants are located in the Houston zone. NRG s Limestone plant is located in the North 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 December 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		
	2007	2006	2005
	(In thousands of MWh)		
Coal	11,527	11,042	11,363
Oil	1,169	1,217	3,148
Gas	1,467	1,050	1,735
Total	14,163	13,309	16,246

NRG s Northeast region assets are located in or near load centers and inside chronic transmission constraints such as New York City, Southwest Connecticut and the Delmarva Peninsula. Assets in these areas tend to attract higher capacity revenues and higher energy revenues and thus present opportunities for repowering these sites. The Company seeks to enhance the value of these sites primarily through the advocacy of capacity market reforms that better reflect their locational value. Over the past year, the Company has benefited from the introduction of more robust capacity market reforms in both the New England Power Pool, or NEPOOL, and PJM. The Locational Forward Reserve Markets, or LFRM, in the NEPOOL, was effective October 1, 2006, and the transition capacity payments were effective December 1, 2006 with an initial price of $3.05/kw month. In all three LFRM auctions to date, the market has cleared at the administratively set price of $14/kw month reflecting the shortage of peaking generation especially in the Connecticut zone. These relatively new markets serve as a prelude to the full implementation of the Forward Capacity Market, or FCM, which begins June 1, 2010, and for which the first auction was conducted in February 2008. PJM s reliability pricing model, or RPM, was effective June 1, 2007 and the Company has participated in auctions providing capacity price certainty through May 2011.

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 2007, Middletown and Montville were covered by an RMR agreement. Unless terminated earlier, these agreements will terminate on June 1, 2010 which coincides with the commencement of the FCM in NEPOOL. On July 16, 2007, FERC conditionally accepted, subject to refund, the Company s RMR filing for its Norwalk plant. This RMR was retroactive to June 19, 2007, which coincides with the FERC decision to eliminate PUSH bidding. The Company is engaged in settlement discussions with FERC to determine the actual value of the RMR payment this plant should receive. In the recently-concluded FCM auction for delivery year 2010/2011, the Company sought to de-list Norwalk s units 1 and 2. ISO-NE declined to accept that de-list bid on the grounds these units were needed for reliability. Norwalk will likely operate pursuant to an RMR agreement after June 1, 2010.

Generation Facilities

As of December 31, 2007, NRG s generation facilities in the Northeast region consisted of approximately 6,980 MW of generation capacity, including assets located in transmission constrained areas, such as 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 (MW)**	**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	740	Coal
Astoria Gas Turbines	Queens, NY	100.0	550	Natural Gas
Huntley	Tonawanda, NY	100.0	380	Coal
Dunkirk	Dunkirk, NY	100.0	530	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	65	Coal
Total Northeast Region			**6,980**	

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 generation 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 generation 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 530 MW from four baseload units. Units 1 and 2 produce up to 75 MW each and were put in service in 1950, and Units 3 and 4 produce approximately 190 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.

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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 net generation capacity of 380 MW from 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 63 and 64 are inactive and were officially retired in May 2006. NRG retired 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 through the use of low sulfur PRB coal and through installation of back end control facilities referred to as baghouses. Construction of the back end control facilities commenced in 2007 and is anticipated to be completed in fall of 2008 for the Huntley facility and fall of 2009 for the Dunkirk facility.

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 electric steam units, Units 1 through 4 and one 15 MW combustion turbine, bringing total plant capacity to approximately 740 MW. Units 1 and 2 are each 80 MW of capacity and were placed in service in 1957 and 1959, respectively. Unit 3 is 155 MW of capacity and was placed in service in 1970, while Unit 4 is 410 MW of capacity and was placed in service in 1980. Units 3 and 4 are equipped with selective non-catalytic reduction 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. Pursuant to a consent order dated September 25, 2007, between NRG and DNREC, NRG agreed to operate the units in a manner that would limit the emissions of NO_x, SO_2 and mercury. Further, the Company agreed to mothball unit 2 by May 1, 2010, and unit 1 by May 1, 2011, and has notified PJM of the plan to mothball these units. In the absence of the appropriate control technology installed at this facility, Units 3 and 4 totaling approximately 565 MW, could not operate beyond December 31, 2011, per terms of the consent order.

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 financially firm, day-ahead unit commitment market. The second is a 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.

SOUTH CENTRAL

As of December 31, 2007, 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 three factors: (1) its position as a significant coal-fired generator in a market that is highly dependent on natural gas for power generation, (2) its long-term contractual and historical service relationship with eleven rural cooperatives around Louisiana, and (3) its ability to make incremental wholesale energy sales during periods when its coal-fired capacity exceeds the cooperative contract requirements. The South Central region works with its cooperative customers to expand their and the Company s customer bases on terms advantageous to all parties. The Company also works within the confines of the Entergy Transmission System to obtain paths for these incremental sales as well as secure transmission service for long-term sales or expansions.

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

	Net Generation		
	2007	2006	2005
	(In thousands of MWh)		
Coal	10,812	10,968	9,924
Gas	118	68	85
Total	10,930	11,036	10,009

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, 2007 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, 2007, 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 advanced low-NO_x burners and overfire air systems. The generators on Units 1 and 3 have been rewound, and the turbine controls on these units have been replaced with a modern digital control system. Unit 2 is scheduled for a generator rewind and turbine controls replacement in future years. Additionally, the turbine high and intermediate pressure steam path on Unit 3 was replaced with a high-efficiency design. Units 1 and 2 are scheduled for similar upgrades in future years. These improvements are expected to cost approximately $28 million. As part of future CAIR and CAMR emission reductions, work is being finalized in the evaluation of installation of new environmental equipment and/or participation in Cap and Trade as allowed in Louisiana s implementation plan.

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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. In the South Central region, all power sales and purchases are consummated bilaterally between individual counterparties. Transacting counterparties are required to procure transmission service from the relevant transmission owners at their FERC-approved tariff rates.

As of December 31, 2007, NRG had long-term all-requirements contracts with eleven Louisiana distribution cooperatives with initial terms ranging from five to twenty-five years. The South Central region has seven contracts in the region 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 the region s contract load requirement.

During limited peak demand periods, the load requirements of these contract customers exceed the baseload capacity of NRG s coal-fired Big Cajun II plant. During such peak demand periods, NRG typically employs its own gas-fired assets, or alternatively purchases power from external sources frequently at higher prices than can be recovered under the Company s contracts. As the load of the region s customers grows, the Company can expect this imbalance to worsen, unless NRG is successful in renegotiating the terms of these long-term contracts or purchasing other low-cost generation to meet demand. 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 structured agreements to reduce or eliminate the need for spot market purchases.

WEST

NRG s portfolio in the West region currently consists of the Long Beach Generating Station, the El Segundo Generating Station, the Encina Generating Station and Cabrillo II, which consists of 12 combustion turbines located in San Diego county. In addition, NRG owns a 50% interest in the Saguaro power plant located in Nevada. On March 31, 2006, NRG purchased Dynegy Inc s 50% ownership interest in WCP and became the sole owner of the WCP assets. 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 and the development of repowering projects that leverage off of existing assets and sites, and the preservation of 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 RFPs and eventually into a capacity market, and (2) using existing emission allowances to permit new, more efficient generating units at existing sites or siting plants at less valuable property and (3) optimizing the value of the region s coastal property for other purposes.

The Company s Encina Generating Station has sold all energy and capacity, 965 MW, in the aggregate, to a load-serving entity through 2009, on a tolling basis, and recovers its operating costs plus a capacity payment. The tolling agreement includes the sale of Resource Adequacy, or RA, capacity and consequently the RMR contract with the CAISO on the Encina units has been terminated effective December 31, 2007. CAISO and Cabrillo Power I, LLC, Encina s owner, entered into dual fuel and black start agreements to supplement the availability obligations to the CAISO provided for under the tolling agreements. 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. For calendar year 2008, the El Segundo station has entered into Resource Adequacy, or RA, contracts with multiple load-serving entities or power marketers, and a tolling agreement with a power marketer for the period May 1, 2008 through December 31, 2008, covering 387 MW of the available 670 MW. Cabrillo II sold 28 MW of RA capacity for 2008 and 88 MW of RA capacity from January 1, 2009 through November 30, 2013. To the extent not covered by an RA agreement, Cabrillo II s cost of operations including a return on investment is covered by an RMR agreement that extends through December 31, 2008. It is expected that Cabrillo II s RMR status will be renewed in 2009.

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 Olin (formerly known as Pioneer), whose contract was extended in 2007 for an additional two years, 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, 2007 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
Long Beach	Long Beach, CA	100.0	260	Natural Gas
Cabrillo II	San Diego, CA	100.0	190	Natural Gas
Saguaro	Henderson, NV	50.0	45	Natural Gas
Total West Region			**2,130**	

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 for use only during 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 have 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.

Long Beach On August 1, 2007, the Company successfully completed and commissioned the repowering of 260 MW of new gas-fired generating capacity at its Long Beach Generating Station. This new generation provides needed support for the summer peak demand to Southern California Edison, or SCE, and California Independent System Operator systems. This project is backed by a 10-year PPA executed with SCE in November 2006. Total capital spending for the project was approximately $78 million.

Cabrillo II Cabrillo II consists of 12 combustion turbines located on 4 sites throughout San Diego county with an aggregate generating capacity of 190 MW. The combustion turbines were installed between 1968 and 1972 and are operated under a license agreement with SDG&E through 2013. The combustion turbines provide peaking services and serve a reliability function for the CAISO.

Market Framework

NRG s assets in the West region primarily consist of older, higher heat rate, natural gas-fired plants in southern California. These plants, while older and less efficient than newer combined cycle plants, provide an important

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reliability function and were 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. Although CAISO retains the option of renewing units as RMR, the current market framework obligates Load Serving Entities to buy a portion of their capacity requirements in the local areas where their load resides. This local procurement obligation drives in part demand for RA or tolling agreements on the units.

California s investor-owned utilities are sponsoring competitive solicitations for new fossil and renewable generating capacity. NRG has submitted offers for new generation capacity to be constructed at the El Segundo and Encina sites. The new projects are in the process of siting permit review by the California Energy Commission and their respective regional air districts, and are supported by air emissions credits that have been banked after the retirement of older generating units. While neither project will be constructed without a long-term off-take agreement with a credit worthy counter-party, both projects have cost and location advantages that enhance their competitive prospects.

INTERNATIONAL

As of December 31, 2007, NRG, through certain foreign subsidiaries, had investments in power generation projects located in Australia, Germany and Brazil with approximately 1,235 MW of generation 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, 2007, are summarized in the table below:

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

(a) NRG entered into an agreement to sell ITISA on December 18, 2007. The sale is subject to regulatory and customary closing conditions.

Australia On June 8, 2006, NRG announced the sale of the Company s 37.5% equity interest in the Gladstone power station, Gladstone, and NRG subsidiary, Gladstone Operating Services, to Transfield Services an Australia-based company, for a purchase price of approximately $209 million (AU$239 million), subject to customary purchase price adjustments. The members of the Gladstone joint venture have withheld consent to NRG s sale of its equity interest in the venture and the transfer of NRG s rights and obligations in the operation and maintenance contract. NRG will continue to seek to close the transaction in 2008 as agreed or on alternative terms.

Germany NRG s interests in Germany include a 50% equity interest in MIBRAG, which mines approximately 16 million metric tonnes of lignite per year and owns 150 MW of electric generation capacity, and a 41.9% 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 84% of MIBRAG s revenues is generated from lignite sales. MIBRAG s generation capacity comprises three plants, 33% of their output is used to power MIBRAG s mining operations and the balance is sold, either under a contract or at spot, primarily to EnviaM, the local distribution utility. NRG, through its wholly-owned subsidiary Saale Energie GmbH, or SEG, owns 400 MW of the Schkopau plant s electric capacity which is sold under a long-term contract to Vattenfall Europe Generation, AG.

Brazil Through its wholly-owned subsidiary Tosli Acquisition B.V., or Tosli, a Netherlands private limited liability company, NRG owns a 99.2% voting equity interest in a 156 MW hydroelectric power plant through Itiquira Energetica S.A., or ITISA, which is located in the state of Mato Grosso, Brazil. On December 18, 2007, NRG entered into a sale and purchase agreement to sell its 100% interest in Tosli to Brookfield Power Inc., a wholly-owned subsidiary of Brookfield Asset Management Inc., a Canadian asset management company, focused on property, power and infrastructure assets, for a purchase price of approximately $288 million, plus the assumption of approximately $60 million in debt. The sale is subject to the receipt of regulatory approval and other customary closing conditions. NRG anticipates completion of the sale transaction during first half 2008 and as discussed in Item 3 Note 3, *Discontinued Operations*, the activities of Tosli and ITISA have been classified as discontinued operations.

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 1,040 megawatts thermal equivalent, or MWt. As of December 31, 2007, NRG Thermal provided steam heating to approximately 525 customers and chilled water to 100 customers in five 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 contract terms with their customers. In addition, NRG Thermal owns and operates a thermal project that serves an industrial customer with high-pressure steam. NRG Thermal also owns an 88 MW combustion turbine peaking generation facility and a 16 MW coal-fired cogeneration facility in Dover, Delaware as well as a 12 MW gas-fired project in Harrisburg, Pennsylvania. Approximately 36% 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 rate 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 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 its 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.

NRG filed the most recent triennial update of its market power analysis on March 26, 2007, and this filing was accepted by FERC on August 9, 2007. On June 21, 2007, FERC issued its long-awaited final rule on market-based rates for wholesale sales of electric energy, capacity, and ancillary services. Of particular note to NRG, the new rule now requires applicants to use submarkets within an RTO region as the relevant geographic market, specifically identifying Southwest Connecticut (and the Connecticut Import interface), New York City, and PJM East as such submarkets. The impact of this rule, and any additional mitigation that may be imposed by FERC as a result of a determination of market power in a submarket, cannot be determined at this time.

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 is 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. As the ERO, NERC has the ability to assess financial penalties for non-compliance. In addition to complying with NERC requirements, each NRG entity must comply with the requirements of the regional reliability council for the region in which it is located.

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, 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. NRG currently owns only one QF, Saguaro Power Company, a Limited Partnership, which is interconnected to and has a contact with Nevada Power Company. Nevada Power Company is not located in a region with an ISO market.

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 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, those excesses 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. The companies within the Texas region are also regulated as a Qualified Scheduling Entity. PUCT also has jurisdiction over

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power generation companies with regard to their sales in the wholesale markets, the implementation of measures to address undue market power or price volatility, and the administration of nuclear decommissioning trusts. The PUCT exercises its jurisdiction both directly, and indirectly, through its oversight of ERCOT, the regional transmission organization. NRG Power Marketing LLC, or 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 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 are being implemented, and it is not clear whether they will operate effectively 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 services, 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.

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 will terminate upon the commencement of the Forward Capacity Market, or FCM, as discussed below. The Devon RMR Agreement terminated on December 31, 2006. On July 16, 2007, FERC conditionally accepted, subject to refund, an RMR agreement filed on April 26, 2007 by Norwalk Power for its units 1 and 2, specifying a June 19, 2007 effective date. Norwalk s RMR rate, as well as its eligibility for the RMR agreement determined based upon the facility s projected market revenues and costs, are subject to further proceedings. Norwalk filed for the RMR agreement in response to FERC s order eliminating the Peaking Unit Safe Harbor bidding mechanism which took effect on June 19, 2007. In the recently-concluded FCM auction for delivery year 2010/2011, the Company sought to de-list Norwalk s units 1 and 2. ISO-NE declined to accept that de-list bid on the grounds these units were needed for reliability. Norwalk will likely operate pursuant to an RMR agreement after June 1, 2010.

On December 28, 2006, the Attorneys General of the State of Connecticut and Commonwealth of Massachusetts filed in the U.S. Court of Appeals for the D.C. Circuit an appeal of the FERC orders accepting the settlement of the New England capacity market design. 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. The first FCM auction for the 2010/2011 delivery year was concluded on February 6, 2008, and bidding reached the minimum floor price of $4.50 per kW-month. A successful appeal by the Attorneys General could disturb the settlement and create a refund obligation of interim capacity transition payments. Oral arguments were held on February 14, 2008.

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

The state-wide Installed Reserve Margin, or IRM, is set annually by the New York State Reliability Council, or NYSRC, and affects the overall demand for capacity in the New York market. On December 14, 2007, the NYSRC approved a 2008 IRM of 15%, which is a reduction of 1.5% from last year s requirement and effectively offsets any increased demand for capacity that would have occurred due to load growth. Additionally, on January 29, 2008, FERC accepted the NYISO s installed capacity demand curves for 2008/2009, 2009/2010, and 2010/2011. The demand curves serve as a critical determinant of capacity market prices, and if approved, would potentially increase prices slightly in the rest-of-state market while reducing prices below their current levels in the New York City market for the next two years, all other factors remaining constant.

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 establishing a new capacity market mechanism, 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 has conducted the RPM auctions for the 2007/2008, 2008/2009, 2009/2010, and 2010/2011 delivery years, and has been operating under the RPM since June 1, 2007. Several parties, however, have appealed the FERC s order accepting the settlement. A successful appeal could potentially disrupt RPM implementation and create a refund obligation. On January 31, 2008, PJM submitted to FERC a proposal to increase its Cost of New Entry, which is a critical component of the demand curve in the RPM market, for the 2011/2012 delivery year. PJM s proposed increase is opposed by consumer interests.

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 the region s existing operations by revising the manner in which transmission service is obtained. Compounding the uncertainty caused by the transition to the ICT, FERC has promulgated new regulations with respect to its pro-forma open access transmission tariff, referred to as Order No. 890, that may affect South Central s ability to transmit, and thus buy and sell, power.

West Region

California has transitioned to a market structure where load-serving entities, or LSEs, have an obligation to procure a portion of their Resource Adequacy, or RA, capacity requirements in transmission-constrained areas. All of NRG s California assets operate in one or more of these constrained areas. This local procurement obligation is leading to a phase-out of RMR agreements with the CAISO, although CAISO retains the option of renewing RMR agreements as necessary to maintain local reliability. During 2008, only Cabrillo Power II LLC will be operating under an RMR agreement, and only for ten of its twelve peaking units. Cabrillo Power I LLC s Encina facility terminated its RMR agreement with CAISO effective December 31, 2007. Please see the *Regional Business Description* for a discussion of the contracting activities that have occurred on the units pursuant to the state s RA program.

There is no organized capacity market in California. As noted above, the CPUC has imposed local capacity requirements on load-serving entities but the application of this Resource Adequacy Capacity Product obligation is uneven. On December 20, 2007, FERC ordered the CAISO to extend its Reliability Capacity Services Tariff, which was set to expire on December 31, 2007, until the implementation of the CAISO s Market Redesign and Technology Upgrade, or MRTU, or an alternate backstop capacity procurement mechanism, and initiated an investigation into the justness and reasonableness of the existing capacity procurement process. It is unclear what compensation will be provided to generators needed for reliability purposes. In addition, several generators, including El Segundo Power, LLC, filed a complaint at FERC on November 30, 2007, similarly seeking just and reasonable compensation for the value of capacity-related reliability services.

On September 21, 2006, FERC conditionally accepted the MRTU proposal which is currently scheduled to go into effect during 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 appealed FERC s orders accepting the MRTU proposal, seeking to materially modify the proposal and/or delay its implementation.

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 emission controls 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 U.S 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. The rule was challenged by New Jersey and ten other states. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated USEPA s rule delisting coal- and oil-fired electric generating units from regulation under CAA §112 (the Delisting Rule) and CAMR. More specifically, cap and trade, allowing power plants to meet emission targets by buying credits, was struck. The three-judge panel agreed with the states that challenged the rule that the USEPA did not have the authority to exempt power plants. Certain states in which NRG operates coal plants, such as Delaware, Massachusetts and New York adopted state implementation plans which did not permit trading in lieu of the CAMR federal implementation plan. Texas and Louisiana adopted the federal CAMR through the state implementation plan, or SIP process. USEPA has already approved the Louisiana SIP, but Texas has not yet been approved. At this time, it is unclear how programs in these states will be affected by the Court s actions.

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, or D.C., and caps both 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. Furthermore: (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 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 were required to 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 by the Company beyond those required by CAIR.

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, and Prevention of Significant Deterioration, or PSD, requirements. The USEPA 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 the USEPA about resolving the claims. See the South Central region below for a further discussion.

There is a growing consensus in the U.S. and globally that GHG emissions are a major cause of global warming. At the national level and at various regional and state levels, policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentives to reduce them. In addition, earlier this year, the U.S. Supreme Court found that CO_2, the most common GHG, could be regulated as a pollutant and that the USEPA should regulate CO_2 emissions from mobile sources. Since power plants, particularly coal-fired plants, are a significant source of GHG emissions both in the United States and globally, it is almost certain that GHG regulatory actions will encompass power plants as well as other GHG emitting stationary sources. In 2007, in the course of producing approximately 80 million MWh of electricity,

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NRG s power plants emitted 68 million tonnes of CO_2 of which 61 million tonnes were emitted in the United States, 3 million tonnes in Australia and 4 million tonnes in Germany.

Federal, state or regional regulation of GHG emissions could have a material impact on the Company s financial performance. The actual impact on the Company s financial performance will depend on a number of factors, including the overall level of GHG reductions required under any such regulations, the price and availability of offsets, and the extent to which NRG would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market. For example, the U.S. Senate is currently considering climate change legislation sponsored by Senators Lieberman and Warner. If legislation with the same level of allocations to existing generation resources and emissions reductions as those contained in the current version of the Lieberman-Warner legislation were enacted, NRG expects that the legislation will have minimal impact on the Company s financial performance through the next decade. Thereafter, under such legislation as currently drafted, the impact on NRG would depend on the Company s level of success in developing and deploying low and no carbon technologies being pursued as part of our *Repowering*NRG and econrg initiatives.

Water In July 2004, the USEPA published rules governing cooling water intake structures at existing power facilities commonly referred to as the Phase II 316(b) rules. These 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. USEPA* 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 the USEPA for reconsideration and restricted their ability to allow generators to substitute mitigation for aquatic specie losses through habitat restoration or other measures. In July 2007, the USEPA suspended the rule, except for the requirement that permitting agencies develop best professional judgment controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The Phase II 316(b) rule affects a number of NRG s plants, specifically those with once-through cooling systems. While NRG has included the capital costs associated with the rule within the Company s estimated environmental capital expenditures based on good faith estimates, until consultations on the plans have occurred with USEPA or its delegated state or regional agencies, and the USEPA has concluded its reconsideration of the Phase II 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. Consistent with the Act, owners of nuclear plants, including the 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 to be 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, the 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.

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Regional U.S. Environmental Initiatives

Northeast Region

NRG s facilities in the eastern U.S. are subject to a cap-and-trade program governing NO_x emissions during the ozone season, which typically begins May 1 and lasts 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 have been allocated NO_x emission allowances. NRG currently estimates that its total NO_x emission allowances is 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 the Company s NO_x 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 emission allowances could have a material adverse effect on the Company s results of operations, financial position and cash flows.

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 are implemented on a state by state basis. 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, several northeastern states entered into a Memorandum of Understanding, or MOU, to create a RGGI to establish a cap-and-trade GHG program for electric generators. The RGGI states are now in the process of promulgating state regulations needed for implementation. To date, all declared states have selected, with the exception of specific set asides, to auction all of the allowances. With state legislation and regulation in place, the first regional auction of RGGI allowances needed by power generators could be held as early as the summer of 2008. Approximately 12 million tonnes of CO_2 were emitted from the Company s generating units in Connecticut, Delaware, Maryland, Massachusetts and New York that will likely be subject to RGGI in 2009. The impact of RGGI on power prices (and thus on the Company s financial performance), indirectly through generators seeking to pass through the cost of their CO_2 emissions, cannot be predicted. However, NRG believes that due to the absence of allowance allocations under RGGI, the direct financial impact on NRG is likely to be negative as the Company will incur costs in the course of securing the necessary allowances and offsets at auction and in the market.

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 its 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 approved by the MADEP in 2007.

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 rate requirement will apply in 2008. It is expected that Somerset will purchase offsets to comply.

New York NRG s 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 compliance will be achieved with the installation of baghouses to further control particulates at

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the Huntley and Dunkirk facilities in 2008 and 2009, respectively. In 2007, NRG accrued amounts payable to NYSDEC of $0.3 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 plan to install controls at the Company s Indian River facility, while on an accelerated basis, was unable to meet certain deadlines, taking into account the time required, as a practical matter, to design, install and commission the necessary equipment. NRG filed a challenge to Reg 1146 with the Environmental Appeals Board, or EAB, on December 6, 2006. In addition, NRG also filed a protective appeal with the Delaware Superior Court on December 29, 2006. This challenge was settled when DNREC and NRG signed a Consent Order on September 25, 2007, and filed that document with the Delaware Superior Court thereby ending the case. Under this agreement, continued operations at the Company s Indian River Generating Station are conditioned upon installation of controls on Units 1 and 2 by May 1, 2008, to reduce NO_x; installation of controls on Units 1-4 by January 1, 2009 to meet mercury requirements; mothball of Units 1 and 2 by May 1, 2011, and May 1, 2010, respectively; and installation of advanced controls on Units 3 and 4 in 2011 to further reduce NO_x and SO_2. If the plant emits NO_x in excess of 1,700 tons in any given ozone season, it will be subject to a graduated scale of stipulated penalties, up to a maximum $2,500/ton. The capital costs associated with this settlement are included in the Company s estimated environmental capital expenditures. In the absence of the appropriate control technology installed at this facility, Units 3 and 4 totaling approximately 565 MW, could not operate beyond December 31, 2011, per terms of the consent order.

West Region

On September 27, 2006, Governor Arnold Schwarzenegger signed Assembly Bill 32, or AB32, California Global Warming Solutions Act of 2006. AB 32 requires the California Air Resources Board, or CARB, to develop a GHG reduction program to reduce emissions to 1990 levels by 2020, a reduction of approximately 25%. The reductions are to be phased in beginning 2012 pursuant to regulations to be adopted by 2011. NRG does not expect that implementation of AB32 in California will have a significant adverse financial impact on the Company for a variety of reasons, including the fact that NRG s California portfolio consists of natural gas-fired peaking facilities and will likely be able to pass through any costs of purchasing allowances in power prices.

South Central Region

On January 27, 2004, NRG s Louisiana Generating, LLC and the Company s Big Cajun II plant received a request under Section 114 of the Clean Air Act from the United States Environmental Protection Agency, or USEPA, seeking information primarily related to physical changes made at the Big Cajun II plant, and subsequently received a notice of violation, or NOV, on February 15, 2005, alleging that NRG s predecessors had undertaken projects that triggered requirements under the Prevention of Significant Deterioration program, including the installation of emission controls. NRG submitted multiple responses commencing February 27, 2004 and ending on October 20, 2004. On May 9, 2006, these entities received from the Department of Justice, or DOJ, a Notice of Deficiency related to their responses, to which NRG responded on May 22, 2006. A document review was conducted at NRG s Louisiana Generating, LLC offices by the DOJ during the week of August 14, 2006. On December 8, 2006, the USEPA issued a supplemental NOV updating the original February 15, 2005 NOV. Discussions with the USEPA are ongoing and the Company cannot predict with certainty the outcome of this matter.

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 reviews 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 D.C. 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 s 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. On October 1, 2007, NRG filed a Facility Evaluation with DNREC, through the Voluntary Clean-up Program to investigate the site. DNREC responded to the Facility Evaluation on February 4, 2008 finding no further action is required in relation to surface water and that a previously planned shoreline stabilization project would adequately address shore line erosion. The landfill itself will require a further Remedial Investigation and Feasibility Study to determine the type and scope of any additional work required. Until the Remedial Investigation and Feasibility Study is completed, the Company is unable to predict the impact of any required remediation.

Further details regarding the Company s Domestic Site Remediation obligations can be found in 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, an international treaty related to greenhouse gas emissions enacted on February 16, 2005, as well as 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 affect the Company s international operations.

MIBRAG/Schkopau, Germany On June 22, 2007, Germany enacted the German National CO_2 Allocation Plan 2008 2012, in which MIBRAG was granted CO_2 allocations that are less than the needs of its three generating plants. The financial impact of this regulation on MIBRAG s results is not yet clear and management of MIBRAG is implementing a number of options to minimize any adverse impact. MIBRAG has also submitted an application under the hardship clause of the law to receive a higher allocation of the CO_2 allowances. The cost of compliance with the CO_2 regulation for NRG s Schkopau plant is expected to be passed through to its off-taker of energy under its existing PPA.

Gladstone, Australia On December 3, 2007, Australia ratified the Kyoto Protocol that commits to targets for GHG reductions. Australia also set a target to reduce greenhouse gas emissions to 60% of 2000 levels by 2050. The government is establishing a single national system for reporting of GHG, abatement actions, and energy consumption and generation starting July 1, 2008. This will underpin the Australian Emissions Trading Scheme, currently in the early stages of design that will be operational no later than 2010.

Available Information

NRG s annual reports on Form 10-K, quarterly reports on Form 10-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 it 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 material 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

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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 2013, 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 the 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.

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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.

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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, *Accounting for Derivative Instruments and Hedging Activities,* as amended, or SFAS 133, 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.

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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 may incur additional costs or delays in the construction and operation of new plants, improvements to existing plants, or the implementation of environmental control equipment at existing plants and may not be able to recover their investment or complete the project.

The Company is in the process of constructing new generation facilities, improving its existing facilities and adding environmental controls to its existing facilities. 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;
- exchange rate risks; 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. Insurance is maintained to protect against these risks, warranties are generally obtained for limited periods relating to the construction of each project and its equipment in varying degrees, and contractors and equipment suppliers are obligated to meet certain performance levels. The insurance, warranties or performance guarantees, however, may not be adequate to cover increased expenses. As a result, a project may cost more than projected and may be unable to fund principal and interest payments under its construction financing obligations, if any. A default under such a financing obligation could result in losing the Company s interest in a power generation facility.

If the Company is unable to complete the development or construction of a facility or environmental control, or decides to delay or cancel such project, it may not be able to recover its investment in that facility or environmental control. Furthermore, if construction projects are not completed according to specification, the Company may incur liabilities and suffer reduced plant efficiency, higher operating costs and reduced net income.

The Company s RepoweringNRG program is subject to financing 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 EPC contracts, construction costs, PPAs 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 project 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.

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.

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

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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 owns 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 1,175 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 the Company s plants. Should NRG fail 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.

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Environmental laws and regulations have generally become more stringent over time, and the Company expects this trend to continue. Future federally imposed changes in the National Ambient Air Quality Standard for ozone could result in additional reduction of NO_x limits or reduced compliance flexibility for power generating units. Challenges to CAMR, if successful, could result in a unit by unit command and control approach to mercury resulting in additional controls to NRG coal facilities in Louisiana and Texas.

Furthermore, 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 its 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.

Policies at the national, regional and state levels to regulate GHG emissions could adversely impact NRG s result of operations, financial condition and cash flows.

There is a growing consensus in the U.S. and globally that GHG emissions are a major cause of global warming. At the national level and at various regional and state levels, policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentive to reduce them. Earlier this year, the U.S. Supreme Court found that CO_2, the most common GHG, could be regulated as a pollutant and that the USEPA should regulate CO_2 emissions from mobile sources. Since power plants, particularly coal-fired plants, are a significant source of GHG emissions both in the United States and globally, it is almost certain that GHG regulatory actions will encompass power plants as well as other GHG emitting stationary sources. In 2007, in the course of producing approximately 80 million MWh of electricity, NRG s power plants emitted 68 million tonnes of CO_2 of which 61 million tonnes were emitted in the United States, 3 million tonnes in Australia and 4 million tonnes in Germany.

Federal, state or regional regulation of GHG emissions could have a material impact on the Company s financial performance. The actual impact on the Company s financial performance will depend on a number of factors, including the overall level of GHG reductions required under any such regulations, the price and availability of offsets, and the extent to which NRG would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market.

State and regional initiatives such as the RGGI, in the Northeast, and the Western Climate Initiative, or WCI, are developing market based programs to counteract climate change. The RGGI states are in the process of promulgating state regulations needed for implementation with six of the ten states issuing drafts for comment. With state legislation and regulation in place, the first regional auction of RGGI allowances needed by power generators could be held as early as the summer of 2008.

However, of the approximately 61 million tonnes of CO_2 emitted by NRG in the United States in 2007, approximately 12 million tonnes were emitted from the Company s generating units in Connecticut, Delaware, Maryland, Massachusetts and New York that will likely be subject to RGGI in 2009. The impact of RGGI on power prices (and thus on the Company s financial performance), indirectly through generators seeking to pass through the cost of their CO_2 emissions, cannot be predicted. However, NRG believes that due to the absence of allowance allocations under RGGI, the direct financial impact on NRG is likely to be negative as the Company will incur costs in the course of securing the necessary allowances and offsets at auction and in the market.

NRG s business, financial condition and results of operations could be adversely impacted by strikes or work stoppages by its unionized employees or inability to replace employees as they retire.

As of December 31, 2007, approximately 66% of NRG s employees at its U.S. generation plants were 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. In addition, a number of our employees at our plants are close to retirement. Our inability to replace those workers could create potential knowledge and expertise gaps as those workers retire.

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. The likelihood of such occurances and their overall effect upon NRG may vary greatly from country to country and are not predictable. 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, or return capital to stockholders. It could also 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 return capital to stockholders or otherwise 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.

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.

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.

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 , 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

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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 2007 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 and increased regulation of carbon dioxide and other greenhouse gas emissions;

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

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

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

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

NRG s ability to implement its econrg strategy of finding ways to meet the challenges of climate change, clean air and protecting our natural resources while taking advantage of business opportunities; and

NRG s ability to achieve its strategy of regularly returning capital to shareholders.

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.

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Item 2 *Properties*

Listed below are descriptions of NRG s interests in facilities, operations and/or projects owned as of December 31, 2007. 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, 2007. The following table summarizes NRG s power production and cogeneration facilities by region:

Name and Location of Facility	Power Market	% Owned	Net Generation Capacity(MW)	Primary Fuel-type
Texas Region:				
W. A. Parish, Thompsons, Texas	ERCOT	100.0	2,460	Coal
Limestone, Jewett, Texas	ERCOT	100.0	1,690	Lignite/Coal
South Texas Project, Bay City, Texas[(a)]	ERCOT	44.0	1,175	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	740	Coal
Astoria Gas Turbines, Queens, New York	NYISO	100.0	550	Natural Gas
Dunkirk, New York	NYISO	100.0	530	Coal
Huntley, Tonawanda, New York	NYISO	100.0	380	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

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Name and Location of Facility	Power Market	% Owned	Net Generation Capacity(MW)	Primary Fuel-type
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	65	Coal
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
Saguaro Power Co., Henderson, Nevada	WECC	50.0	45	Natural Gas
Long Beach, California	CAISO	100.0	260	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(c)	Schkopau & Lippendorf/ ENVIA	50.0	75	Lignite
ITISA, Brazil(d)	COPEL	99.2	155	Hydro

(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) Primarily a coal mining facility

(d) On December 18, 2007, NRG entered into a sale and purchase agreement to sell its interest in ITISA to Brookfield Power, a wholly-owned subsidiary of Brookfield Asset Management Inc., for a purchase price of approximately $288 million, plus the assumption of approximately $60 million in debt, subject to regulatory approvals and other closing conditions. NRG anticipates completion of the sale transactions during the first half

2008 as discussed in Item 15 Note 3, *Discontinued Operations, Business Acquisitions and Dispositions.*

The following table summarizes NRG s thermal facilities as of December 31, 2007:

Name and Location of Facility	Thermal Energy Purchaser	% Ownership Interest	Generating Capacity
NRG Energy Center Minneapolis, Minnesota	Approx. 100 steam customers and 50 chilled water customers	100.0	Steam: 1,203 MMBtu/hr. (353 MWt) Chilled Water: 42,630 tons (150 MWt)
NRG Energy Center San Francisco, California	Approx. 170 steam customers	100.0	Steam: 454 MMBtu/Hr. (133 MWt)
NRG Energy Center Harrisburg, Pennsylvania	Approx. 230 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, Pennsylvania	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, California	Approx. 20 chilled water customers	100.0	Chilled water: 7,425 tons (26 MWt)
Camas Power Boiler Camas, Washington	Georgia-Pacific Corp.	100.0	Steam: 200 MMBtu/hr. (59 MWt)
NRG Energy Center Dover, Delaware	Kraft Foods Inc.	100.0	Steam: 190 MMBtu/hr. (56 MWt)
Paxton Creek Cogeneration, Harrisburg, Pennsylvania	PJM	100.0	12 MW Natural Gas
Dover Cogeneration, Delaware	PJM	100.0	104 MW Natural Gas/Coal

Other Properties

In addition, NRG owns several real property and facilities relating to its generation assets, other vacant real property unrelated to the Company s 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 space.

Item 3 ***Legal Proceedings***

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)*; ***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)*; ***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)*; ***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. Defendants motion to dismiss was denied by the Court on June 22, 2005, and the cases are in discovery. Dynegy is defending WCP pursuant to an indemnification agreement. In October 2007 Dynegy reached a tentative agreement with plaintiffs to settle these cases. Such settlement requires court approval and proceedings seeking court approval are ongoing. If such settlement was approved, WCP would pay no funds towards that settlement as Dynegy is defending and indemnifying WCP.

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. There are no further cases relating to electricity, but should any such new cases arise, Dynegy s counsel would represent 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.

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. On May 3, 2007, WCP and the other defendants filed separate petitions for certiorari seeking review by the U.S. Supreme Court and on September 25, 2007, the Court agreed to hear two of the filed petitions. Although WCP s petition was not selected for review, the Court s ultimate decision with respect to the other defendants petitions will apply equally to WCP. Briefs on behalf of the petitioners, the United States, and friends of the Court were filed in November 2007. Oral argument took place on February 19, 2008, with a decision expected by the end of the year. 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 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. On September 11, 2007, the parties argued the dispute before a three judge arbitration panel. On February 19, 2008, the parties executed a settlement agreement ending the arbitration. A component of the settlement requires approval from ISO-NE.

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., **Federal Energy Regulatory Commission Docket No. EL 03-27-000** *(filed November 26, 2002)* 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 April 30, 2007, the U.S. Supreme Court denied NiMo s request for review of the D.C. Circuit decision thus ending further avenues to appeal FERC s ruling in this matter. NRG believes it is adequately reserved.

Spring Creek Coal Company v. NRG Texas LP, NRG South Texas Power LP, NRG Texas Power LLC, NRG Texas LLC,, and NRG Energy, Inc. **Case No. 2:07-cv-00168-CAB, U.S. District Court for the District of Wyoming-Cheyenne Division** *(filed July 30, 2007, amended compliant filed December 3, 2007)* The complaint alleges multiple breaches in 2007 of a 1978 coal supply agreement as amended by a later 1987 agreement, which plaintiff alleges is a take or pay contract. Plaintiff is seeking damages of approximately $18 million. Certain of the defendants filed a motion to dismiss for lack of personal jurisdiction and certain other defendants filed a motion to dismiss for lack of a case in controversy. The court will hear oral argument on these and other motions on July 11, 2008. The trial has been scheduled to begin on September 8, 2008.

***Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et. al*, U.S. District Court for the Northern District of California** *(filed February 26, 2008)* Numerous electric generating companies and oil and gas companies have been named as defendants in this complaint, which has been filed but not yet served on NRG. Damages of up to $400 million have been asserted. The complaint alleges that the carbon dioxide emissions of defendants contribute to global climate change which has harmed the plaintiffs. The complaint is filed on behalf of an Alaskan town made up of native tribes and seeks damages associated with those tribes having to relocate from the northern coast of Alaska, purportedly because of the effects of global warming.

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 are 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 Company s balance sheets. Similarly, NRG removed the obligations relevant to the claims from the balance sheets when the common stock was issued and cash contributed.

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company s Chapter 11 bankruptcy plan totaling $25 million in cash and 5,082,000 shares of common stock. As of February 7, 2008, the reserve held approximately $10 million in cash and approximately 1,317,138 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 16,000,000 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% Redeemable Perpetual Preferred Stock, (ii) 3.625% Convertible Perpetual Preferred Stock, and (iii) 5.75% Mandatory Convertible Preferred Stock.

On April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. All share and per share amounts within this Form 10-K retroactively reflect the effect of the stock split.

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 2007 and 2006 are set forth below:

Common Stock Price	Fourth Quarter 2007	Third Quarter 2007	Second Quarter 2007	First Quarter 2007	Fourth Quarter 2006	Third Quarter 2006	Second Quarter 2006	First Quarter 2006
High	$ 47.19	$ 45.08	$ 45.93	$ 37.10	$ 29.74	$ 25.58	$ 26.31	$ 24.73
Low	38.79	34.76	35.98	$ 27.22	22.14	22.13	21.22	20.90
Closing	$ 43.34	$ 42.29	$ 41.57	$ 36.02	$ 28.00	$ 22.65	$ 24.09	$ 22.61

NRG had 236,734,929 shares outstanding as of December 31, 2007, and as of February 25, 2008, there were 236,442,274 shares outstanding. As of February 25, 2008, there were approximately 58,900 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 for the year ended December 31, 2007, were as follows:

For the Year Ended December 31, 2007	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	3,000,000	$ 34.38	3,000,000	$ 165,160,714
Second quarter	2,669,200	42.16	2,669,200	52,613,935
Third quarter	1,337,500	39.38	1,337,500	
Fourth quarter	2,037,700	41.82		
Total for 2007	9,044,400	$ 39.09	7,006,700	

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On November 3, 2006, as part of Phase II of the Company s Capital Allocation Program discussed in Item 15 Note 13, *Capital Structure*, NRG announced an increase to the share repurchase program to a $500 million stock buyback. As originally announced on August 1, 2006, Phase II was only to be a $250 million stock buyback. NRG completed Phase II during the third quarter 2007.

As part of the Company s ongoing Capital Allocation Program, the Company initiated its 2008 program in December 2007. The Company repurchased 2,037,700 shares of NRG common stock during that month in the open market for approximately $85 million. In January 2008, the Company repurchased an additional 344,000 shares of NRG common stock on the open market for approximately $15 million.

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	7,180,589	$ 19.98	7,941,758(a)
Equity compensation plans not approved by security holders		N/A	
Total	7,180,589	$ 19.98	7,941,758(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 16,000,000, on a post-split basis, 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 7,941,758 and 8,602,978 shares of common stock remaining available for grants of awards under NRG s LTIP as of December 31, 2007 and 2006, respectively.

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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, 2007 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

	Jan-2004	Dec-2004	Dec-2005	Dec-2006	Dec-2007
NRG Energy, Inc.	$ 100.00	$ 160.58	$ 209.89	$ 249.49	$ 386.10
S&P 500	100.00	111.22	116.68	135.11	142.53
UTY	$ 100.00	$ 126.23	$ 149.50	$ 179.67	$ 213.76

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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 3, *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.

In addition, on April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. All share and per share amounts within this Form 10-K retroactively reflect the effect of the stock split.

	Reorganized NRG					Predecessor Company
	Year Ended December 31,				December 6 December 31,	January 1 December 5,
	2007	2006	2005	2004	2003	2003
	(In millions except ratio and per share data)					
Statement of income data:						
Total operating revenues	$ 5,989	$ 5,585	$ 2,400	$ 2,080	$ 120	$ 1,570
Total operating costs and expenses	5,060	4,720	2,290	1,848	109	(1,671)
Income from continuing operations, net	569	543	68	157	12	3,180
Income/(loss) from discontinued operations, net	17	78	16	29	(1)	(414)
Net income	586	621	84	186	11	2,766
Common share data:						
Basic shares outstanding average	240	258	169	199	200	
Diluted shares outstanding average	288	301	171	201	200	
Shares outstanding end of year	237	245	161	174	200	
Per share data:						
Income from continuing operations basic	2.14	1.90	0.28	0.78	0.06	
	1.95	1.78	0.28	0.78	0.06	

Income from continuing operations diluted						
Net income basic	2.21	2.21	0.38	0.93	0.06	
Net income diluted	2.01	2.04	0.38	0.93	0.06	
Book value	19.48	19.48	11.31	13.14	12.19	
Business metrics:						
Cash flow from operations	1,517	408	68	645	(589)	238
Liquidity position	$ 2,715	$ 2,227	$ 758	$ 1,600	$ 1,545	N/A
Ratio of earnings to fixed charges	2.28	2.38	1.48	1.93	1.76	11.92
Ratio of earnings to fixed charges and preference dividends	2.03	2.09	1.30	1.92	1.76	11.92
Return on equity	10.65	10.98	3.77	6.91	N/A	N/A
Ratio of debt to total capitalization	55.70	57.38	44.91	44.57	56.14	N/A
Balance sheet data:						
Current assets	$ 3,562	$ 3,083	$ 2,197	$ 2,119	$ 2,183	N/A
Current liabilities	2,277	2,032	1,357	1,090	2,096	N/A
Property, plant and equipment, net	11,320	11,546	2,559	2,639	3,271	N/A
Total assets	19,274	19,436	7,467	7,906	9,336	N/A
Long-term debt, including current maturities and capital leases	8,361	8,726	2,456	3,220	3,648	N/A
Total stockholders equity	$ 5,504	$ 5,658	$ 2,231	$ 2,692	$ 2,437	N/A

N/A not applicable

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

	Reorganized NRG					Predecessor Company
					December 6	January 1
	Year Ended December 31,				December 31,	December 5,
	2007	2006	2005	2004	2003	2003
	(In millions except ratio and per share data)					
Energy	$ 4,265	$ 3,155	$ 1,840	$ 1,181	$ 52	$ 769
Capacity	1,196	1,516	563	612	37	566
Risk management activities	4	124	(292)	61		19
Contract amortization	242	628	9	(6)	13	
Thermal	125	124	124	112	9	24
Hedge Reset		(129)				
Other	157	167	156	120	9	192
Total operating revenues	$ 5,989	$ 5,585	$ 2,400	$ 2,080	$ 120	$ 1,570

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. Also see Item 15 Note 5, *Accounting for Derivatives and Hedging Activities*, to the Consolidated Financial Statements for a further discussion.

Other revenue primarily consists of operations and maintenance fees, or 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.

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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 for the year ended December 31, 2007, 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 new and ongoing initiatives 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, 2007, 2006 and 2005. 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; 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., or NRG or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets. As of December 31, 2007, NRG had a total global portfolio of 191 active operating generation units at 49 power generation plants, with an aggregate generation capacity of approximately 24,115 MW and approximately 740 MW under construction which includes partnership interests. Within the United States, NRG has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,880 MW of generation capacity in 175 active generating units at 43 plants. These power generation facilities are primarily located in Texas (approximately 10,805 MW), the Northeast (approximately 6,980 MW), South Central (approximately 2,850 MW), and West (approximately 2,130 MW) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets. NRG s principal domestic power plants consist of a mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 46%, 33%, 16% and 5% of the Company s total domestic generation capacity, respectively. In addition, 15% of NRG s domestic generating facilities have dual or multiple fuel capacity, which allows plants to

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dispatch with the lowest cost fuel option. NRG s domestic generation facilities consist of baseload, intermediate and peaking power generation facilities, the ranking of which is referred to as Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s 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.

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 principles:

Increase value from existing assets NRG has a highly diversified portfolio of power generation assets in terms of region, fuel-type and dispatch levels. Through the *FOR*NRG initiative, 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 improving the Company s return on invested capital, or ROIC.

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 (i) leveraging its expertise in marketing power and ancillary services, (ii) its knowledge of markets, (iii) its balanced financial structure and (iv) its diverse portfolio of power generation assets.

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. Through the *Repowering*NRG initiative, NRG will continue 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 GHG, emissions or can be equipped to capture and sequester GHG emissions.

Reduce carbon intensity of portfolio while taking advantage of carbon-driven business opportunities NRG continues to actively pursue investments in new generating facilities and technologies that will be highly efficient and will employ no and low carbon technologies to limit CO_2 emissions and other air emission. Through the *Repowering*NRG and econrg initiatives, NRG is focused on the development of low or no GHG emitting energy generating sources, such as nuclear, wind, clean coal and gas, and the employment of post-combustion capture technologies, which represents significant commercial opportunities.

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, the Company s ongoing capital allocation objective includes scheduled repayment of debt based on the amount of cash flow by the Company each year, as well as an annual return of capital to shareholders, targeted at an average rate of 3% of market capitalization, of approximately $250 million to $300 million per year.

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 markets. 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 Emerging trends impacting the power industry include (a) increased regulatory and political scrutiny, (b) financial credit market disruptions triggered by sub-prime investment losses which may have, in part, contributed to current recessionary pressures, and (c) the development of power capacity markets intended to induce new investment in order to address tightening reserve margins. The industry dynamics and external influences that will affect the Company and the power generation industry in 2008 and for the medium term include:

Carbon At the national level and at various regional and state levels, policies are under development to regulate GHG emissions, including CO_2, the most common pollutant, thereby effectively putting a cost on such emissions in order to create financial incentive to reduce them. It is almost certain that GHG regulatory schemes will encompass power plants, with the impact on the Company s financial performance depending on a number of factors, including the overall level of GHG reductions required under any such regulation, the price and availability of offsets, and the extent to which NRG would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market. While the passing and timing of legislation remains uncertain, the Company expects that the impact of such legislation on the Company s financial performance, as such legislation is currently proposed, to have a minimal impact through the next decade. Thereafter, the impact would depend on the level of success of the Company s multifold strategy, which includes (a) shaping public policy with the objective being constructive and effective federal GHG regulatory policy, and (b) pursuing its *Repowering*NRG and econrg programs. The Company s multifold strategy is discussed in greater detail in Item 1, *Business* under Carbon Update.

Financial Credit Market Availability and Domestic Recessionary Pressures. Triggered largely by the decay in sub-prime credit markets, the cost of credit has sharply increased while credit availability has declined. Capital intensive generators rely on the credit markets for liquidity and for the financing of power generation investments. Concurrently, economic indicators are pointing towards a potential slowdown in the United States economy. A sharp downturn in U.S. housing, the tighter credit conditions, and disappointing employment numbers, amongst other data have highlighted the risk of economic recession. Historically, an economic recession results in lower power demand and power prices. If an economic recession does occur in the near term it is unlikely to have a material impact on the Company due to the hedged position of its portfolio.

Consolidation Over the long-term, industry consolidation is expected to occur, with mergers and acquisitions activity in the power generation sector likely to involve utility-merchant or merchant-merchant combinations. There may also be interest by foreign power companies, particularly European utilities, in the American power generation sector. However, for the near-term, and particularly in the coming year, given the current financial market environment along with the uncertainty surrounding domestic carbon legislation, consolidation is less likely.

Infrastructure Development In response to record peak power demand, tightening reserve margins, and volatile natural gas prices, the power generation industry has announced significant expansion plans for both transmission and generation. In addition to traditional gas-fired capacity, much of the new generation announced would be from non-gas fuel sources, including nuclear and renewable sources. During 2007, 18 gigawatts of previously announced pulverized coal generation projects were canceled due to increasing public and political concern regarding carbon emissions. The Energy Policy Act of 2005 created financial incentives for non-traditional baseload generation, such as advance nuclear and clean coal technologies in order to reduce reliance on the more traditional pulverized coal technologies. Depending on the timing and location of this new construction, as well as the construction activity in the oil and petrochemical sectors, access to experienced engineers, skilled operators, and maintenance workers could impact the timing and costs of these projects.

Market Developments A number of the markets NRG serves are currently undergoing changes. NE-ISO held its first auction in February 2008 for 2010 capacity commitments as part of its FCM, while in California, MRTU is scheduled to go into effect on April 1, 2008. PJM completed its first RPM auctions during 2007. The primary objective of these market re-designs are 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. In addition to these capacity market developments, in December 2008, ERCOT is expected to fully implement the Texas Nodal Protocols, which will revise the wholesale market design to incorporate locational marginal pricing, replacing the existing zonal wholesale market design. The ERCOT market design is expected to reduce local transmission congestion costs, with impacts on pricing uncertain at this time.

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.

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.

Stock Split

On April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. All share and per share amounts within this Form 10-K retroactively reflect the effect of the stock split.

Environmental Matters, Regulatory Matters and Legal Proceedings

NRG discusses details of its other 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 regulatory matters in Item 15 Note 22, *Regulatory 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, 2007, 2006 and 2005, 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 are 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, including the Company s targeted net debt to total capital ratio range of 45% to 60% and certain cash flow and interest coverage ratios. 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 to shareholders through opportunistic share repurchases, while exploring other prospects to increase its flexibility under restrictive debt covenants.

Repowering, econrg and new build opportunities   The Company intends to pursue repowering initiatives that enhance and diversify its portfolio and provide a targeted economic return to the Company.

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Significant events during the year ended December 31, 2007

Results of Operations

Impact of Hedge Reset in November 2006, the Company reset legacy Texas hedges which resulted in an increase in energy revenue of $449 million as the period s average contract prices increased by approximately $13 per MWh as compared to the 2006 average contract prices.

Development costs NRG incurred $101 million in net development costs primarily due to required engineering studies to obtain the Combined Construction and Operating License Application, or COLA, as well as development costs for other *Repowering*NRG projects. On September 24, 2007, NRG filed a COLA with the NRC to build and operate two new nuclear units at the STP site. Effective October 29, 2007, the City of San Antonio agreed to partner with NRG in the development and ownership of these new units, to reimburse NRG for a pro rata share of certain project costs NRG had incurred, and to pay a pro rata share of future development costs. NRG was reimbursed $42 million for costs incurred to develop STP 3 and 4 through October 31, 2007; $39 million of the total $42 million was recorded as a reduction to development costs.

Acquisition of Texas and WCP the inclusion of a full year of activity for the Texas region and WCP in 2007, contributed to an increase in operating income of approximately $76 million, compared to 2006.

New capacity markets the introduction of the Locational Forward Reserve Market, or LFRM, the Reliability Pricing Model market, or RPM, and transition capacity payment markets, increased capacity revenues in the Northeast region by $78 million.

Refinancing expense the Company recognized a $35 million write-off of previously deferred financing cost due to the refinancing of the Company s Senior Credit Facility.

Interest expense the increase in debt due to the acquisition of Texas Genco LLC, Hedge Reset transaction and the Capital Allocation Program increased interest expense by approximately $99 million.

Sale of ITISA on December 18, 2007, NRG entered into a sale and purchase agreement to sell its 100% interest in Tosli, which holds all of NRG s interest in ITISA, to Brookfield Asset Management Inc. for the purchase price of $288 million, plus the assumption of approximately $60 million in debt. NRG anticipates the completion of the sale transaction during the first half of 2008. As discussed in Note 3 *Discontinued Operations, Business Acquisitions and Dispositions* the activities of Tosli and ITISA have been classified in discontinued operations.

Other

STP Repowerings The NRC docketed the Company s COLA on November 30, 2007, signaling the beginning of their comprehensive and detailed review process. The Company expects to achieve commercial operation for Unit 3 approximately 48 months after issuance of the COLA, and commercial operation for Unit 4 approximately 12 months thereafter.

Cedar Bayou Generating Station on August 1, 2007, NRG and a partner entered into definitive agreements pursuant to which the two parties will jointly develop, construct, operate and own, on a 50/50 undivided interest basis, a new 550 MW combined cycle natural gas turbine generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas. In exchange for a 50% undivided interest in certain tangible and intangible assets and rights to use facilities owned by NRG, the partner agreed to pay NRG $45 million during a 24-month period.

Long Beach on August 1, 2007, the Company successfully completed and commissioned the repowering of 260 MW of new gas-fired generating capacity at its Long Beach Generating Station. This project is supported by a 10-year PPA.

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Consolidated Results of Operations

2007 compared to 2006

The following table provides selected financial information for NRG Energy, Inc., for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Change
	2007	2006	%
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 4,265	$ 3,155	35%
Capacity revenue	1,196	1,516	(21)
Risk management activities	4	124	N/A
Contract amortization	242	628	(61)
Thermal revenue	125	124	1
Hedge Reset		(129)	N/A
Other revenues	157	167	(6)
Total operating revenues	5,989	5,585	7
Operating Costs and Expenses			
Cost of operations	3,378	3,265	3
Depreciation and amortization	658	590	12
General and administrative	309	276	12
Development costs	101	36	181
Total operating costs and expenses	4,446	4,167	7
Gain on sale of assets	17		N/A
Operating Income	1,560	1,418	10
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	54	60	(10)
Gains on sales of equity method investments	1	8	(88)
Other income, net	55	156	(65)
Refinancing expenses	(35)	(187)	(81)
Interest expense	(689)	(590)	17
Total other expenses	(614)	(553)	11
Income from Continuing Operations before income tax expense	946	865	9
Income tax expense	377	322	17
Income from Continuing Operations	569	543	5
Income from discontinued operations, net of income tax expense	17	78	(78)

Net Income		$ 586	$ 621	(6)
Business Metrics				
Average natural gas price	Henry Hub ($/MMbtu)	7.12	6.99	2%

N/A-Not applicable

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Operating Revenues

Operating revenues increased by $404 million for the year ended December 31, 2007, compared to 2006. This was due to:

Energy revenues energy revenues increased by $1.1 billion for the year ended December 31, 2007, compared to 2006:

Texas energy revenues increased by $972 million of which $217 million was due to the inclusion of twelve months activity in 2007 compared to eleven months in 2006. Of the remaining $755 million increase, $449 million was due to the Hedge Reset transaction which resulted in higher 2007 average contracted prices of approximately $13 per MWh. In addition, revenues from 8.8 million MWh of generation moved from capacity revenue to energy revenue. Prior to the Acquisition, PUCT regulations required that Texas sell 15% of its capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG s request to no longer participate in these auctions and that capacity is now being sold in the merchant market. These favorable results were partially offset by lower sales from the region s natural gas-fired units due to a cooler summer which resulted in lower generation of approximately 2.7 million MWh.

Northeast energy revenues increased by approximately $138 million, of which $61 million was due to a 6% increase in generation, primarily driven by increases at the region s Arthur Kill, Oswego and Indian River plants. The Arthur Kill plant increased generation by 448 thousand MWh due to transmission constraints around New York City, the Oswego plants generation increased by 127 thousand MWh due to a colder winter during 2007 compared to 2006, and the Indian River plants generation increased by 418 thousand MWh due to stronger pricing and fewer outages in the second half of 2007 compared to the second half of 2006.

South Central energy revenues increased by approximately $70 million, due to a new contract which increased contract sales volume by approximately 1.3 million MWh and energy revenues by $69 million. Following a contractual fuel adjustment charge, energy revenues increased by $11 million from the region s cooperative customers. This was offset by a $12 million decrease in merchant energy revenue.

West energy revenues decreased by approximately $72 million, excluding the first quarter 2007, due to the tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment in return for the right to schedule and dispatch from the plant. The Encina tolling agreement replaced an RMR agreement under which the plant was called upon to generate and earn energy revenues for such dispatch.

Capacity revenues capacity revenues decreased by $320 million for the year ended December 31, 2007, compared to 2006, due to a decrease in Texas capacity revenues that were partially offset by increases in capacity revenues in the Northeast, South Central and West regions:

Texas capacity revenues decreased by $486 million due to a reduction of capacity auction sales mandated by the PUCT in prior years as previously discussed.

Northeast capacity revenues increased by $81 million of which $39 million of the increase was from the region s NEPOOL assets and $36 million was from the region s PJM assets. The NEPOOL assets benefited from the new LFRM market and transition capacity market, both introduced in the fourth quarter 2006. Capacity revenues increased by $24 million from the LFRM market and $18 million from transition capacity payments, which was offset by a $3 million reduction in capacity payments due to the expiration of the Devon plant s RMR agreement on December 31, 2006. On June 1, 2007, the new RPM capacity market became effective in PJM increasing capacity revenues by $36 million as compared to 2006.

South Central capacity revenues increased by approximately $22 million. Of this increase, $15 million was due to higher billing rates as a result of the region s market setting new summer peaks hit in 2006 and 2007, $6 million was due to higher contractual transmission pass-though costs to the region s cooperative customers and $3 million was due to improved market conditions at the region s Rockford plants. In

August 2007, the region set a new system peak of 2,123 MW which will continue to impact capacity revenue in the first half of 2008.

West capacity revenues increased by approximately $54 million, of which $26 million was related to the inclusion of the first quarter 2007 compared to 2006. New tolling agreements at the region s Encina and Long Beach plants accounted for the remaining difference, with the Encina facility contributing approximately $15 million and the newly-repowered Long Beach facility contributing approximately $13 million.

Contract amortization revenues from contract amortization decreased by $386 million for the year ended December 31, 2007, compared to 2006, as a result of the November 2006 Hedge Reset transaction, which resulted in a write-off of a large portion of the Company s out-of-market power contracts during the fourth quarter 2006.

Other revenues other revenues decreased by $10 million for the year ended December 31, 2007, compared to 2006 due to:

Sale of emission allowances net sales of SO_2 emission allowances decreased by approximately $33 million. In 2006, we sold emissions in lieu of generation due to an unseasonably warm first quarter. Since that time the average market price for SO_2 allowances decreased by 28%.

Physical gas sales decreased by $7 million due to the lower sales of excess natural gas.

Ancillary revenues ancillary services revenue increased by approximately $27 million due to a change in strategy to actively provide ancillary services in the Texas region which increased revenues by $33 million. This was partially offset by a $4 million reduction in ancillary services in the Northeast region due to higher transmission costs following transmission constraints in the New York City area.

Risk management activities gains/losses from risk management activities include all derivative activity that do not qualify for hedge accounting as well as the ineffective portion associated with hedged transactions. Such gains were $4 million for the year ended December 31, 2007. The breakdown of changes by region are as follows:

	Year Ended December 31, 2007			
	Texas	Northeast	South Central	Total
	(In millions)			
Net gains on settled positions, or financial revenues	$ 33	$ 43	$ 5	$ 81
Mark-to-market results				
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	(83)	(45)		(128)
Reversal of previously recognized unrealized gains on settled positions related to trading activity	(1)	(12)	(19)	(32)
Net unrealized gains on open positions related to economic hedges	19	15		34
Net unrealized gains/(losses) on open positions related to trading activity	(1)	26	24	49

Subtotal mark-to-market results	(66)	(16)	5	(77)
Total derivative gains/(losses)	$ (33)	$ 27	$ 10	$ 4

Risk management activities that did not qualify for hedge accounting treatment resulted in a total derivative gain of approximately $4 million for the year ended December 31, 2007 compared to a $124 million gain for the year ended December 31, 2006. NRG s 2007 derivative gain was comprised of $77 million mark-to-market losses and $81 million in settled gains, or financial revenue. Of the $77 million of mark-to-market losses, $128 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $32 million from the reversal of mark-to-market gains previously recognized on trading activity. Both of these losses ultimately settled as financial revenues during 2007. The $34 million gain from economic hedge positions was comprised of a

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$20 million increase in the value of forward sales of electricity and fuel due to favorable power and gas prices and a $14 million gain from hedge accounting ineffectiveness. This ineffectiveness was primarily related to gas swaps and collars in the Texas region due to a change in the correlation between natural gas and power prices. NRG also recognized a $49 million unrealized gain associated with the Company s trading activity.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues. In late 2006 and during the course of 2007, NRG hedged a portion of the Company s 2007 and 2008 generation. Since that time, the settled and forward prices of electricity and natural gas have decreased, resulting in the recognition of unrealized mark-to-market forward gains and the settlement of realized positions at a gain. In 2006, NRG recognized forward mark-to-market gains as forward prices of electricity decreased relative to its positions forward; settled loss positions were driven by the out-of-market gas swaps acquired with the Texas Genco purchase.

Cost of Operations

Cost of operations for the year ended December 31, 2007, increased by $113 million compared to 2006, but as a percentage of revenues it was 56% for 2007 compared to 58% for 2006.

Cost of energy cost of energy decreased by approximately $24 million, to $2,428 million, for the year ended December 31, 2007, compared to 2006, and as a percentage of revenue it decreased from 44% for the year ended December 31, 2006, to 41% for the year ended December 31, 2007. This decrease was due to:

Texas decreased by $95 million for the year ended December 31, 2007, compared to 2006. This included an additional month s expense of $96 million in 2007, without which cost of energy would have decreased by $191 million. This decrease was due to a reduction in natural gas expense and fuel contract amortization, partially offset by increased ancillary service expense.

Fuel expense and purchased power expense Natural gas expense decreased by $170 million, which excludes January 2007 natural gas expense of $27 million. This was due to a decrease of 2.7 million MWh in gas-fired generation as a result of cooler summer weather, coupled with greater economic purchases from ERCOT and increased baseload generation. Despite higher coal-fired generation at the region s W.A. Parish and Limestone plants, the region s coal expenses, excluding January 2007, decreased by $13 million due to a 9% reduction in average contracted coal prices.

Fuel contract amortization decreased by approximately $43 million, excluding January 2007, due to declining forward fuel price curves below the contracted prices used at Acquisition.

Purchased ancillary service expense increased by approximately $34 million due to favorable market prices in purchasing this service in the market compared to providing the service from internal resources.

Northeast cost of energy increased by $26 million primarily due to $30 million in higher natural gas costs related to increased generation at the region s Arthur Kill plant due to its locational advantage to New York City following transmission constraints during the last three quarters of 2007.

South Central Cost of energy increased by $104 million due to increases in purchased energy, coal costs and transmission costs.

Purchased energy increased by approximately $69 million due to increased market purchases following increased cooperative load requirements and planned maintenance at the region s Big Cajun II facility.

Coal costs increased by approximately $17 million, of which $11 million was related to a 9% increase in coal prices and $7 million due to higher coal transportation costs.

Transmission costs increased by approximately $16 million of which $6 million was due to contractual increases related to network transmission service. Point-to-point transmission costs also increased by $10 million reflecting more off-system sales.

West Cost of energy decreased by approximately $76 million, excluding the first quarter 2007, due to new tolling agreement entered into at the Encina plant in 2007, which requires the counterparty to supply their own fuel. Under the previous arrangement in 2006, the plant supplied the fuel.

Other operating costs Other operating costs which includes operations and maintenance expenses, or O&M, increased by $137 million, to $950 million, for the year ended December 31, 2007, compared to 2006. This increase was due to:

Texas other operating costs increased by $75 million, after excluding January 2007 expense of $39 million, other operating costs increased by $36 million. This $36 million increase was due to $25 million in higher O&M expense as a result of increased maintenance associated with planned outages and fuel handling at the W.A. Parish facility and $10 million in higher property tax expenses following an increased valuation after the Acquisition.

Northeast other operating costs increased by $18 million due to increased staffing costs and higher maintenance costs.

South Central other operating costs increased by approximately $28 million, $19 million of which was due to increased maintenance expense primarily related to planned outages. Additionally, the region disposed of $4 million in assets in conjunction with the outage.

Acquisition of WCP these results include $15 million of WCP expenses that were not included in the Company s results in 2006.

Depreciation and Amortization

NRG s depreciation and amortization expense for the year ended December 31, 2007, increased by $68 million compared to 2006. This increase was due to:

Texas acquisition the inclusion of Texas results for twelve months in 2007 compared to eleven months in 2006 resulted in an increase of approximately $38 million.

Impact of new environmental legislation due to new and more restrictive environmental legislation, the useful life of certain pollution control equipment has been reduced. The Company accelerated depreciation on certain equipment in its Northeast region to reflect the remaining useful life, resulting in increased depreciation of approximately $13 million.

General and Administrative

NRG s G&A costs for the year ended December 31, 2007, increased by $33 million compared to 2006, and as a percentage of revenues was 5% in both 2007 and 2006. This increase was due to:

Texas and WCP acquisitions the inclusion of Texas results for twelve months in 2007 compared to eleven months in 2006 and the consolidation of WCP for the last three quarters of 2006 resulted in an increase of approximately $9 million.

Wage and benefit costs due to the expansion of the Company, including *Repowering*NRG initiatives, wages and related benefits costs resulted in a $28 million increase in G&A. Additionally, information technology and other office services to support this expansion increased by $8 million.

Franchise tax the Company s Louisiana state franchise tax increased by approximately $6 million. This was because the state s franchise tax is assessed based on the Company s total debt and equity that increased significantly following the acquisition of Texas Genco LLC.

Non-recurring expenses during 2006 for the year ended December 31, 2006, G&A included non-recurring fees of $20 million of which $6 million were related to the unsolicited takeover attempt by Mirant Corporation and $14 million associated with the Texas integration efforts.

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Development Costs

NRG s development costs for the year ended December 31, 2007, increased by $65 million. These costs were due to the Company s *Repowering*NRG projects:

Texas on September 24, 2007, NRG filed a COLA with the NRC to build and operate two new nuclear units at the STP site. During the period, NRG incurred $91 million in development costs related to STP units 3 and 4 project in 2007. These development costs were reduced by a $39 million reimbursement related to a partnership agreement signed during the fourth quarter 2007.

Wind projects approximately $13 million in development costs related to wind projects primarily in Texas.

Other project approximately $4 million in development costs related to other *Repowering*NRG projects in the West region.

Gain on Sale of Assets

NRG s net gain on sale of assets for the year ended December 31, 2007, was approximately $17 million. On January 3, 2007, NRG completed the sale of the Company s Red Bluff and Chowchilla II power plants resulting in a pre-tax gain of approximately $18 million.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates for the year ended December 31, 2007, decreased by $6 million compared to 2006. This decrease was due to the sale of multiple equity investments from which the Company earned $8 million for the year ended December 31, 2006.

Other Income, Net

NRG s other income for the year ended December 31, 2007, decreased by $101 million compared to 2006. This decrease was due to the non-cash settlement during the first quarter 2006 where NRG recorded $67 million of other income associated with a settlement with an equipment manufacturer related to turbine purchase agreements entered into in 1999 and 2001. The settlement resulted in the reversal of accounts payable totaling $35 million resulting from the discharge of the previously recorded liability, and an adjustment to write up the value of the equipment received to its fair value, resulting in income of approximately $32 million. Additionally, in 2006, other income was favorably impacted by a $13 million non-cash gain associated with the discharge of liabilities upon dissolution of an inactive legal entity and a $5 million non-cash gain due to a favorable settlement with respect to post closing adjustments on the acquisition of the Company s western New York plants.

During 2007, the Company recorded an $11 million impairment charge in the fourth quarter related to an investment in commercial paper reducing its carrying value to approximately $32 million. The Company earned $10 million less in interest income in 2007 compared to 2006, due to lower average cash balances.

Interest Expense

NRG s interest expense for the year ended December 31, 2007, increased by $99 million compared to 2006. This increase was due to:

Refinancing for the acquisition of Texas Genco LLC in February 2006 the Company significantly increased its corporate debt facilities from approximately $2 billion as of December 31, 2005, to approximately $7 billion as of February 2, 2006. This increased interest expense by approximately $12 million compared to 2006.

Increase of $1.1 billion in debt for Hedge Reset the Company issued $1.1 billion in Senior Notes due 2017 in November 2006 related to the Hedge Reset, which increased interest expense by approximately $72 million.

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

In the first quarter 2006, NRG entered into interest rate swaps with the objective of fixing the interest rate on a portion of NRG s Senior Credit Facility. These swaps were designated as cash flow hedges under SFAS 133, and the impact associated with ineffectiveness was immaterial to NRG financial results. For the year ended December 31, 2007, NRG had a deferred loss of $31 million in other comprehensive income compared to deferred gains of $16 million in 2006.

Refinancing Expense

Refinancing expense decreased by $152 million for the year ended December 31, 2007, compared to 2006, due to higher expense for the refinancing of the Company s corporate debt for the acquisition of Texas Genco LLC on February 2, 2006, compared to the refinancing of the Company s Senior Credit Facility during 2007.

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

Income Tax Expense

Income tax expense increased by $55 million for the year ended December 31, 2007, compared to 2006. The effective tax rate was 39.9% and 37.2% for the year ended December 31, 2007 and 2006, respectively.

	Year Ended December 31,	
	2007	**2006**
	(In millions except otherwise stated)	
Income from continuing operations before income taxes	$ 946	$ 865
Tax at 35%	331	303
State taxes, net of federal benefit	46	34
Foreign operations	(13)	(21)
Subpart F taxable income		11
Valuation allowance, including change in state effective rate	6	(10)
Change in state effective tax rate		21
Claimant reserve settlements		(28)
Change in local German effective tax rates	(29)	
Foreign dividends	26	1
Non-deductible interest	10	3

Permanent differences, reserves, other		8
Income tax expense	$ 377	$ 322
Effective income tax rate	39.9%	37.2%

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The increase in income tax expense was primarily due to:

Increase in profits income before tax increased by $81 million, with a corresponding increase of approximately $32 million in income tax expense.

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

Change in German tax rate due to a reduction in the German statutory and resulting effective tax rate, income tax expense benefited by $29 million for the year-ended 2007.

Taxable dividends from foreign subsidiaries in January 2007, the Company transferred the proceeds from the sale of its Flinders assets to the U.S. creating additional income tax expense of approximately $25 million.

Lower tax rates in foreign jurisdictions lower income tax rates at the Company s foreign locations resulted in additional income tax expense during 2007 compared to 2006 of $8 million.

Non-deductible interest interest expense from the stock buybacks from Phase I of the Company s Capital Allocation Program were non-deductible for income tax purposes, thus increasing income tax expense by approximately $7 million.

Change in state effective tax rate the state effective tax rate remains unchanged for 2007. This resulted in a net decrease in income tax expense of approximately $5 million as compared to 2006, after taking into account the movement in valuation allowance as a result of the change in rate from 2005 to 2006.

Subpart F taxable income a dividend was declared and paid in 2007 by NRGenerating International B.V. As result of this dividend, there was no Subpart F income compared to 2006. This resulted in a decrease to income tax expense of approximately $11 million.

Disputed claims reserve During 2007 as compared to 2006, the Company made no distribution from its disputed claims reserve, this increased income tax expense by approximately $28 million.

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

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, 2007 and 2006, NRG recorded income from discontinued operations, net of income tax expense of $17 million and $78 million, respectively. Discontinued operations for the year ended December 31, 2007 were comprised of the results of ITISA. Discontinued operations for the year ended December 31, 2006 were comprised of the results of ITISA, Flinders, Audrain and Resource Recovery. 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.

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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	2005	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 3,155	$ 1,840	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	5,585	2,400	133
Operating Costs and Expenses			
Cost of operations	3,265	1,829	79
Depreciation and amortization	590	158	273
General and administrative	276	176	57
Development costs	36		NA
Other charges		12	NA
Total operating costs and expenses	4,167	2,175	92
Operating Income	1,418	225	530
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	156	54	189
Refinancing expenses	(187)	(65)	188
Interest expense	(590)	(177)	233
Total other expenses	(553)	(115)	381
Income from Continuing Operations before income tax expense	865	110	686
Income tax expense	322	42	667
Income from Continuing Operations	543	68	699
Income from discontinued operations, net of income tax expense	78	16	388

Net Income		$ 621	$ 84	639
Business Metrics				
Average natural gas price	Henry Hub ($/MMbtu)	6.99	8.89	(21)%

N/A Not applicable

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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	$ 3,155	$ 1,726	$ 72	$ 1,357	$ 1,840
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	5,585	3,088	141	2,356	2,400
Cost of operations	3,265	1,669	112	1,484	1,829
Depreciation and amortization	590	413	2	175	158
General and administrative	276	111	6	159	176
Development costs	36	14	4	18	
Other charges					12
Total operating costs and expenses	4,167	2,207	124	1,836	2,175
Operating Income	$ 1,418	$ 881	$ 17	$ 520	$ 225

Operating revenues increased by $3,185 million for the year ended December 31, 2006, compared to 2005. However, excluding the Company s Texas region, the Hedge Reset transaction and WCP, total operating revenues decreased by approximately $44 million.

Energy revenues energy revenues increased by $1,315 million for the year ended December 31, 2006, compared to 2005 with 50% contracted in 2006 compared to 13% in 2005. Excluding the Texas region and WCP, energy revenues decreased by approximately $483 million or 26%.

Texas The acquisitions of Texas Genco LLC now referred to as the Company s Texas region, contributed $3,088 million to operating revenues including $1,726 million of energy revenues.

West The acquisition of Dynegy s 50% interest in WCP contributed $72 million to total energy revenues.

Northeast 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.

Capacity revenues capacity revenues were $1,516 million for the year ended December 31, 2006 compared to $563 million for the year ended December 31, 2005, an increase of $953 million. This was due to:

Texas the acquisitions of Texas Genco LLC now referred to as the Company s Texas region, contributed $3,088 million to operating revenues including $849 million of capacity revenues.

West The acquisition of Dynegy s 50% interest in WCP contributed $64 million to total capacity revenues.

Northeast Higher capacity prices for the New York Rest of State market, led to a $30 million increase in the Northeast region s 2006 capacity revenues.

South Central The region s capacity revenues also grew by $9 million as pricing increased due to increased peak demand.

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.

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)		
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 related to economic hedges		115	1		116
Reversal of previously recognized unrealized gains on settled positions related to trading activity		(25)	(1)		(26)
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 gains/(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. 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 unrealized 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). In late 2005 and during the course of 2006, NRG hedged a portion of the Company s 2007 generation. After entering into those transactions the forward prices of electricity decreased, mainly due to mild weather for much of the year in the Northeast region and the downward trend in natural gas prices in 2006. While settled prices also decreased, the Company s 2007 settled loss position was driven by the out-of-market gas swaps acquired with the Texas Genco purchase. In 2005, forward mark-to-market losses and the settlement of positions at losses was related to the run-up in natural gas prices which occurred in the wake of hurricane Katrina and Rita resulting in the recognition of mark-to-market forward sales as gains.

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 $3,265 million or 58% of total operating revenues compared to $1,829 million, or 76%, of total operating revenues for 2005, an increase of $1,436 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 $1,427 million for 2005 to $2,452 million in 2006. The increase of $1,025 million was primarily due to:

> *Texas* The acquisitions of Texas Genco LLC now referred to as the Company s Texas region, increased cost of energy by approximately $1,276 million.

> *West* The acquisition of Dynegy s 50% interest in WCP increased cost of energy by approximately $79 million.

This was partially offset by lower cost of energy in the:

> *Northeast* cost of energy decreased by $254 million, due to $143 million lower oil costs and $101 million in lower gas fuel costs as a result of lower generation from oil- and gas-fired assets of approximately 70% and 45%, respectively.

> *South Central* cost of energy decreased by $66 million 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 $411 million to $813 million, $393 million related to the acquisition of the Company s Texas region and $33 million for WCP. Excluding the impact of NRG Texas and WCP, other operating costs were $15 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 $590 million and $158 million, respectively. The Texas region s depreciation and amortization comprised $413 million of the $432 million year-over-year increase.

General and Administrative

> NRG s G&A costs for 2006 were $276 million compared to $176 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. Excluding WCP and the Company s Texas region G&A was lower by $17 million, despite having been 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.

Development Costs

NRG incurred approximately $36 million in development expenses in 2006 to support its *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:

Purchase of remaining 50% interest in 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.

Sale of Non-Core Assets 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.

This was partially offset by a $4 million improvement in equity income from the Company s MIBRAG investment which 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 $156 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. 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, this was due to:

Refinancing for the acquisition of Texas Genco LLC 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.

Redemption of Second Priority Notes 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

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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 $590 million compared to $177 million for the year ended December 31, 2005. The increase in interest expense was primarily due to:

Financing for the acquisition of Texas Genco LLC interest on new debt issued to finance the acquisition of Texas Genco LLC. See Item 15 Note 3, *Discontinued Operations*, *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. See also 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 increased by $280 million for the year ended December 31, 2006, compared to 2005. The effective tax rate was 37.2% and 38.2% for the year ended December 31, 2006 and 2005, respectively.

	Year Ended December 31,	
	2006	**2005**
	(In millions except otherwise stated)	
Income from continuing operations before income taxes	$ 865	$ 110
Tax at 35%	303	39
State taxes, net of federal benefit	34	(1)
Foreign operations	(21)	(18)
2005 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)	
Foreign dividends	1	
Non-deductible interest	3	
Permanent differences, reserves, other	8	(2)

Income tax expense	$ 322	$ 42
Effective income tax rate	37.2%	38.2%

The increase in income tax expense was primarily due to an increase in income.

Increase in profits income before tax increased by $755 million, with a corresponding increase of approximately $299 million in tax expense.

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

Change in state effective tax rate the state effective tax rate was changed which resulted in a net increase to income tax expense of approximately $11 million, as compared to 2005, inclusive of the movement in valuation allowance resulting from the change in state effective tax rate.

Disputed claims reserve during 2006, the Company made distributions from its disputed claims reserve decreasing 2006 income tax expense by approximately $28 million.

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

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 $78 million and $16 million, respectively. Discontinued operations for the year ended December 31, 2006 were comprised of the results of ITISA, Flinders, Audrain and Resource Recovery. Discontinued operations for 2005 consisted of the results of ITISA, 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.

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Results of Operations Regional Discussions

Texas Region

The following table provides selected financial information for the Texas region for the year ended December 31, 2007, and the period ended December 31, 2006.

	Year Ended December 31, 2007	2006[b]	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 2,698	$ 1,726	56%
Capacity revenue	363	849	(57)
Risk management activities	(33)	(30)	10
Contract amortization	219	609	(64)
Hedge Reset		(129)	N/A
Other revenues	40	63	(37)
Total operating revenues	3,287	3,088	6
Operating Costs and Expenses			
Cost of energy	1,181	1,276	(7)
Depreciation and amortization	469	413	14
Other operating expenses	668	518	29
Operating Income	$ 969	$ 881	10
MWh sold (in thousands)	49,220	46,361	6
MWh generated (in thousands)	47,779	44,910	6
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 62.00	$ 63.07	(2)
Cooling Degree Days, or CDDs[a]	2,707	3,108	(13)
CDD s 30 year rolling average	2,647	2,647	
Heating Degree Days, or HDDs[a]	1,949	1,533	27%
HDD s 30 year rolling average	1,997	1,997	

(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, 2007, operating income increased by $88 million compared to 2006, however excluding January 2007 results, operating income increased by $21 million. The primary drivers were:

Energy Revenues for eleven months of 2007 compared to the same period in 2006 were up by $755 million, $449 million of which was due to the Hedge Reset transaction, as the average price of the underlying power contracts increased by $13 per MWh compared to average contract prices prior to the hedge reset. The balance of the increase in energy revenues was due to the sale of additional output as energy rather than under PUCT mandated capacity auctions.

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This favorable result was offset by:

Capacity Revenues reduction in capacity auction sales reduced capacity revenues by approximately $517 million, excluding January 2007.

Contract Amortization the Hedge Reset transaction decreased contract amortization by approximately $498 million, excluding January 2007.

Gas-fired Generation lower natural gas-fired generation of approximately 2.7 million MWh, for the comparable eleven month period in 2007, was a result of cooler summer weather coupled with increased economic purchases of energy and ancillary services from ERCOT. Lower sales revenue for the eleven months was offset by natural lower natural gas fuel costs of $170 million and cash flow economic hedge improvements.

Development Costs increased by $44 million in 2007 compared to 2006 largely due to the development of STP nuclear units 3 and 4 project, including $2 million of expenses in January 2007. The $44 million increase also includes $39 million in reimbursements from a partnership agreement signed in the fourth quarter 2007.

Operating Revenues

Total operating revenues from the Texas region increased by $199 million during the year ended December 31, 2007, compared to 2006. Excluding January 2007, operating revenues decreased by $56 million. This decrease was due to:

Energy revenues energy revenues increased by $972 million of which $217 million was due to the inclusion of twelve months activity in 2007 compared to eleven months in 2006. Of the remaining $755 million increase, $449 million was due to the Hedge Reset transaction which resulted in higher 2007 average contracted prices of approximately $13 per MWh. In addition, revenues from 8.8 million MWh of generation moved from capacity revenue to energy revenue. Prior to the Acquisition, PUCT regulations required that NRG Texas sell 15% of its capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG s request to no longer participate in these auctions and that capacity is now being sold in the merchant market. These favorable results were partially offset by lower sales from natural gas-fired units due to a cooler summer which resulted in lower natural gas-fired generation of approximately 2.7 million MWh.

Other revenues the region s other revenues decreased by $27 million for the eleven months of 2007 compared to 2006. This was due to a decrease in intercompany emission allowance sales of $40 million and a $19 million decrease in physical gas sales. This $59 million decrease was offset by a $33 million increase in ancillary services revenue due to a change in strategy to more actively provide ancillary services in the Texas region.

Capacity revenues capacity revenues decreased by $517 million, excluding $31 million incurred in January 2007. This decrease was due to the reduction of capacity auction sales mandated by the PUCT in prior years as described above.

Contract amortization revenues from contract amortization excluding January 2007 decreased by $405 million primarily due to the write-off of out-of-market power contracts during the fourth quarter 2006 related to the Hedge Reset transaction.

Risk management activities The Texas region recorded a total of $33 million in derivative losses for the year ended December 31, 2007, compared to a $30 million loss for the year ended December 31, 2006. The Texas region s 2007 derivative loss was comprised of $66 million of mark-to-market losses and $33 million in settled gains, or financial revenue. Of the $66 million of mark-to-market losses, $83 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $1 million from the reversal of mark-to-market gains previously recognized on trading activity. Both of these losses ultimately settled as financial revenues during 2007. The $19 million gain from economic hedge positions was comprised of an $8 million increase in the value of forward sales of electricity and fuel due to favorable power and natural gas prices and a $11 million gain

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from hedge accounting ineffectiveness. This ineffectiveness was primarily related to gas swaps and collars due to a change in the correlation between natural gas and power prices.

Cost of Energy

Cost of energy for the Texas region decreased by $95 million for the year ended December 31, 2007, compared to 2006. This included an additional month s expense for January 2007 of $96 million, without which cost of energy would have decreased by $191 million. This was due to:

Fuel expense natural gas expense decreased by $170 million, excluding the January 2007 expense of $27 million, due to a decrease of 2.7 million MWh in natural gas-fired generation as a result of cooler summer weather, coupled with greater economic purchases of energy and ancillary services from ERCOT and increased baseload generation. Coal expenses, excluding January 2007, decreased by $13 million due to an 9% reduction in average contracted coal prices in 2007, despite a 1.1 million MWh increase in coal-fired generation at the region s W.A. Parish and Limestone plants.

Purchased ancillary service increased by approximately $34 million due to the favorable market prices in purchasing this service in the market compared to providing the service from internal resources causing an associated decrease in natural gas expense.

Fuel contract Amortization decreased by approximately $43 million, excluding January 2007, due to declining forward fuel price curves below the contracted prices used at acquisition in February 2006.

Other Operating Expenses

Other operating expenses for the Texas region increased by $150 million for the year ended December 31, 2007 compared to 2006. This included an additional month s expense for January 2007, of $53 million, without which other operating expenses would have increased by $97 million. This was due to:

Development costs on September 24, 2007, NRG filed a COLA with the NRC. The Company incurred $91 million in development costs related to STP nuclear unit 3 and 4 project in 2007, including $2 million in January 2007, compared to development costs of $14 million in 2006. Of the $91 million incurred this year, $39 million was reimbursed through a partnership agreement in the fourth quarter 2007. Fossil development costs was $6 million in 2007.

Plant O&M expense increased by $25 million, excluding January 2007, due to increased maintenance associated with planned outages and fuel handling at W.A. Parish, increased maintenance related to higher utilization in 2006 of the region s natural gas fleet, and retirement of older assets.

Corporate allocations were higher by approximately $16 million.

Property tax expense increased by approximately $10 million related to the Texas acquisition.

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Northeast Region

2007 compared to 2006

The following table provides selected financial information for the Northeast region for the years ended December 31, 2007 and 2006:

	Year Ended December 31, 2007	2006	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 1,104	$ 966	14%
Capacity revenue	402	321	25
Risk management activities	27	144	(81)
Other revenues	72	112	(36)
Total operating revenues	1,605	1,543	4
Operating Costs and Expenses			
Cost of energy	641	615	4
Depreciation and amortization	102	89	15
Other operating expenses	404	378	7
Operating Income	$ 458	$ 461	(1)
MWh sold (in thousands)	14,163	13,309	6
MWh generated (in thousands)	14,163	13,309	6
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 76.37	$ 67.73	13
Cooling Degree Days, or CDDs[(a)]	702	653	8
CDD s 30 year rolling average	537	537	
Heating Degree Days, or HDDs[(a)]	6,074	5,417	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

Operating income decreased by $3 million for the year ended December 31, 2007, compared to 2006, due to:

Cost of energy increased by approximately $26 million due to a 6% increase in generation at the region s coal and natural gas-fired plants.

Other operating expenses increased by $26 million primarily due to increased maintenance and staffing costs combined with higher property tax.

Depreciation increased by $13 million reflecting the additional depreciation expense following the reduction in estimated useful lives of certain components of the region s power plants as a result of new environmental regulation.

Offset by higher operating revenues of approximately $62 million due to increased generation, favorable pricing and the favorable impact from new capacity markets. This was partially offset by lower gains in the region s risk management activities and lower sales of emission allowances due to a 28% reduction in market prices.

Operating Revenues

Operating revenues increased by $62 million for the year ended December 31, 2007, compared to 2006, due to:

Energy revenues increased by approximately $138 million, of which $61 million was due to increased generation, and $88 million due to a 9% increase in average realized market prices partially offset by an $11 million reduction in contracted bilateral energy revenues.

Generation increased by 6%, primarily driven by increases at the region s Arthur Kill, Oswego and Indian River plants. The Arthur Kill plant increased generation by 448 thousand MWh due to transmission constraints around New York City, the Oswego plants generation increased by 127 thousand MWh due to a colder winter during 2007 compared to 2006, and Indian River plants generation increased by 418 thousand MWh due to stronger pricing and fewer outages.

Price on average, realized prices in the Northeast increased by 9% due to a mix of higher priced New York City generation coupled with improved economic energy hedge trading resulting in a $37 million increase in energy revenues.

Capacity revenues increased by $81 million, of which $39 million was from the region s NEPOOL assets, $36 million from the region s PJM assets and $6 million from the region s New York Rest of State assets.

NEPOOL The region s NEPOOL assets benefited from the new LFRM market and transition capacity market, both of which were introduced in the fourth quarter 2006. Capacity revenues increased by $24 million from the LFRM market and $18 million from transition capacity payments, which were partially offset by a $3 million reduction due to the expiration of an RMR agreement for the region s Devon plant on December 31, 2006 and by RMR payments from the region s Norwalk plant which began in the third quarter 2007.

PJM On June 1, 2007, the new RPM capacity market became effective in PJM increasing capacity revenues by approximately $36 million.

NYISO New York Rest of State capacity prices increased by 75% as load requirement growth increased demand for capacity. This was coupled with the impact from the new capacity markets in NEPOOL which reduced exported supply into the New York market that further improved the supply/demand dynamics.

These were partially offset by:

Risk management activities The Northeast region recorded $27 million in derivative gain for the year ended December 31, 2007 compared to a $144 million gain for the year ended December 31, 2006. The region s 2007 derivative gain was comprised of $16 million of mark-to-market losses and $43 million in settled gains, or financial revenue. Of the $16 million of mark-to-market losses, $45 million represents the reversal of mark-to-market gains previously recognized on economic hedges and $12 million from the reversal of mark-to-market gains previously recognized on trading activity. Both of these losses ultimately settled as financial revenues during 2007. The region also recognized a $15 million unrealized gain from economic hedge positions which was comprised primarily of a $13 million increase in the value of forward sales of electricity and fuel due to favorable power and gas prices. The region also recognized a $26 million unrealized gain associated with the Company s trading activity. The $144 million derivative gain for the year ended December 31, 2006 was comprised of a $154 million unrealized mark-to-market gain and $10 million in settled losses. Most of these unrealized gains reversed out in 2007.

Other revenues decreased by $40 million, of which approximately $48 million was due to reduced activity in the trading of emission allowances following both an increase in generation and a 28% decrease in market prices. This decrease was partially offset by an $11 million increase in physical gas sales to third parties due to favorable trading opportunities in the market.

Cost of Energy

Cost of energy increased by $26 million for the year ended December 31, 2007, compared to 2006, primarily due to $30 million in higher natural gas costs related to increased generation at the region s Arthur Kill plant due to its locational advantage to New York City following transmission constraints during the last three quarters of 2007.

Other Operating Expenses

Other operating expenses increased by $26 million for the year ended December 31, 2007, compared to 2006, due to:

Plant O&M spending of $15 million due to increased plant staffing costs of $7 million, increased maintenance costs of $6 million and increased environmental remediation costs of $2 million.

Property tax increased by approximately $3 million due to a favorable tax decision in 2006 related to NYC assets of $10 million partially offset by a tax law change the same year that resulted in a reduction of property tax receivable of $5 million in 2006 and a $2 million reduction in property taxes at the New England plants in 2007.

Regional G&A expenditures Regional staffing and benefits increased by $3 million primarily related to the region s *Repowering*NRG development efforts while corporate allocations increased by $5 million.

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	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	(1)
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)	$ 67.73	$ 91.98	(26)
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

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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 was due to:

Risk management activities of $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. In 2005, forward mark-to-market losses and settlement of positions at losses was related to the run-up in natural gas prices which occurred in the wake of hurricanes Katrina and Rita.

Natural gas costs 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.

This was partially offset by:

Generation 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. 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.

Energy revenues decreased by $478 million to $966 million due to lower generation from the region s Oswego plant and lower realized price from generation from the region s baseload coal plants which reduced energy revenues by $318 million. 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 increased to $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,

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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.

Cost of Energy

Cost of energy decreased by $254 million to $615 million for the year ended December 31, 2006 due to 18% lower generation from the region s generation assets which resulted in a $143 million decrease in oil fuel costs, as lower 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. This was due to:

Plant utilities decreased 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.

Insurance costs decreased by $8 million due to favorable renewals.

Corporate allocations decreased by $14 million due to the inclusion of the Texas region in our allocation methodology.

Offsetting these decreases were:

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 reduce forced outage hours, additional turbine maintenance and oil tank repair costs at the region s Oswego facility.

Development costs increased by $8 million to advance the region s *Repowering*NRG efforts.

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South Central Region

2007 compared to 2006

The following table provides selected financial information for the South Central region for the years ended December 31, 2007 and 2006:

	Year Ended December 31, 2007	2006	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 404	$ 334	21%
Capacity revenue	221	199	11
Risk management activities	10	13	(23)
Contract amortization	23	19	21
Other revenues		5	N/A
Total operating revenues	658	570	15
Operating Costs and Expenses			
Cost of energy	412	308	34
Depreciation and amortization	68	68	
Other operating expenses	121	89	36
Operating Income	$ 57	$ 105	(46)
MWh sold (in thousands)	12,452	11,845	5
MWh generated (in thousands)	10,930	11,036	(1)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 59.62	$ 56.18	6
Cooling Degree Days, or CDDs[a]	1,963	1,797	9
CDD s 30 year rolling average	1,547	1,547	
Heating Degree Days, or HDDs[a]	3,236	3,169	2%
HDD s 30 year rolling average	3,604	3,604	

(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

Operating income for the region declined by $48 million for the year ended December 31, 2007, compared to 2006, due to higher operating expenses, despite a 1% decrease in generation at the region s Big Cajun II plant.

Operating Revenues

Operating revenues increased by $88 million for the year ended December 31, 2007, compared to 2006, due to:

Energy revenues increased by approximately $70 million due to a new contract which contributed $69 million in contract energy revenues, increasing contract sales volume by approximately 1.3 million MWh. A contractual change in the fuel adjustment charge for the region s cooperative customers increased energy revenues by an additional $11 million. This was offset by a $12 million decrease in merchant energy revenue as a result of satisfying increasing load requirement from the new contract.

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Capacity revenues increased by approximately $22 million, of which $15 million was due to higher rates as a result of the region setting new summer peaks in 2006 and 2007; the new system peak of 2,123 MW set in August 2007 will continue to impact capacity revenue in the first half of 2008. Higher network transmission costs, which are passed through to the region s cooperative customers, also increased capacity revenues by $6 million. Improved market conditions in PJM resulted in an increase of $3 million in merchant capacity revenue from the Rockford plants.

Cost of Energy

Cost of energy increased by $104 million for the year ended December 31, 2007, compared to 2006, due to:

Purchased energy increased by approximately $69 million as planned and maintenance outage hours at the region s Big Cajun II facility increased by 1,209 hours, primarily due to the planned turbine/generator outage at the Big Cajun II Unit 3 facility in the fourth quarter 2007. These increases were offset by a drop of $2.53/MWh in realized purchased power prices.

Coal costs increased by approximately $17 million, of which approximately $11 million was due to a 9% increase in coal prices and $7 million due to higher coal transportation costs.

Transmission costs increased by approximately $16 million. Network transmission costs, which are passed-through to the region s cooperative customers, increased by $6 million due to load growth and increased utilization of the Entergy transmission system. Point-to-point transmission costs to support off-system sales increased by $10 million.

Other Operating Expenses

Other operating expenses increased by approximately $32 million for the year ended December 31, 2007, compared to 2006, due to:

Maintenance expense increased by approximately $19 million as the scope of work on planned outages were more extensive in 2007. The Big Cajun II Unit 3 facility incurred a major planned outage in the fourth quarter 2007, during which the generator was rewound, turbine controls were replaced with a modern digital control system, and the turbine steam path was replaced with a high-efficiency design. Asset disposals in conjunction with the outage added $4 million.

Franchise tax Louisiana state franchise tax increased by approximately $6 million due to an increased assessment based on the Company s total debt and equity. The Company s total debt and equity increased significantly following the acquisition of Texas Genco LLC.

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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	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)	$ 56.18	$ 69.96	(20)
Cooling Degree Days, or CDDs[a]	1,797	1,811	(1)
CDD s 30 year rolling average	1,547	1,547	
Heating Degree Days, or HDDs[a]	3,169	3,366	(6)%
HDD s 30 year rolling average	3,604	3,604	

(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. This was due to:

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.

Lower outages 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 allowed for resale of power received from the region s tolling agreements, providing additional margins.

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Total Operating Revenues

Operating revenues increased by $10 million in 2006 compared to 2005. This was due to:

Energy revenues 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.

Risk management activities The region 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 decreased 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. This was due to:

Lower purchased power 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. As a result of improved plant availability, energy purchased by the South Central region to support load contracts dropped 16%. 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.

This was partially offset by:

Transmission costs increased by $7 million due to a combination of contractual increases in network transmission rates and higher peaks in 2006.

Coal costs increased by $25 million, reflecting contractual increases in coal commodity costs and higher plant availability 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.

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West Region

2007 compared to 2006

The following table provides selected financial information for the West region for the years ended December 31, 2007, and 2006:

	Year Ended December 31, 2007	2006	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 4	$ 75	(95)%
Capacity revenue	122	68	79
Risk management activities		(3)	N/A
Other revenues	1	6	(83)
Total operating revenues	127	146	(13)
Operating Costs and Expenses			
Cost of energy	5	80	(94)
Depreciation and amortization	3	3	
Other operating expenses	80	55	45
Operating Income	$ 39	$ 8	388
MWh sold (in thousands)	1,246	1,901	(34)
MWh generated (in thousands)	1,246	1,901	(34)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 66.52	$ 61.54	8
Cooling Degree Days, or CDDs[(a)]	785	926	(15)
CDD s 30 year rolling average	704	704	
Heating Degree Days, or HDDs[(a)]	3,048	3,001	2%
HDD s 30 year rolling average	3,228	3,228	

(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

Operating income increased by $31 million for the year ended December 31, 2007, compared to 2006. Excluding the consolidation of WCP s results following the acquisition of Dynegy s 50% interest on March 31, 2006, operating income increased by $24 million, due to:

Capacity revenues increased by approximately $28 million, excluding the first quarter 2007, due to new tolling agreements at the region s Encina and Long Beach plants:

Encina In January 2007, NRG signed a new tolling agreement for the region s Encina plant which contributed $15 million in capacity revenues for the year ended December 31, 2007.

Long Beach On August 1, 2007, NRG successfully completed the repowering of a 260 MW natural gas-fueled generating plant at its Long Beach generating facility, which contributed approximately $13 million in capacity revenues for the year ended December 31, 2007.

Cost of energy decreased by $76 million, excluding the first quarter 2007, due to the new tolling agreement entered into at the Encina plant in 2007, which required the counterparty to supply their own fuel. Under the previous arrangement in 2006, the plant supplied the fuel.

This increase was offset by:

Energy revenues decreased by approximately $72 million, excluding the first quarter 2007, primarily due to the tolling agreement at the Encina plant that has resulted in the receipt of fixed monthly capacity payment in return for the right to schedule and dispatch from the plant. The Encina tolling agreement replaced the RMR agreement under which the plant was called upon to generate revenues for such dispatch.

O&M expense increased by approximately $6 million, excluding the first quarter 2007, primarily due to increases in labor costs, major maintenance and auxiliary power.

Development expenses increased by $4 million, reflecting *Repowering*NRG initiatives at the region s El Segundo and Encina sites.

Other revenues decreased ancillary service revenue of $3 million at the Encina plant due to the new tolling agreement that consigns ancillary service revenue to the counterparty in exchange for a fixed monthly capacity payment.

2006 compared to 2005

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

	Year Ended December 31, 2006	2005	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 75	$ 1	N/A
Capacity revenue	68		N/A
Risk management activities	(3)		N/A
Other revenues	6	3	100
Total operating revenues	146	4	N/A
Operating Costs and Expenses			
Cost of energy	80	1	N/A
Depreciation and amortization	3	1	200
Other operating expenses	55	8	588
Operating Income/(loss)	$ 8	$ (6)	N/A
MWh sold (in thousands)	1,901	6	N/A

MWh generated (in thousands)	1,901	6	N/A
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 61.54	$ 71.06	(13)
Cooling Degree Days, or CDDs(a)	926	775	19
CDD s 30 year rolling average	704	704	
Heating Degree Days, or HDDs(a)	3,001	2,842	6%
HDD s 30 year rolling average	3,228	3,228	

(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.

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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. 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.

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.

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 for the year ended December 31, 2005.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2007 and 2006, NRG s liquidity was approximately $2.7 billion and $2.2 billion, respectively, comprised of the following:

As of December 31,	**2007**	**2006**
	(In millions)	
Cash and cash equivalents	$ 1,132	$ 795
Restricted cash	29	44
Total cash	1,161	839
Synthetic letter of credit availability	557	533
Revolver credit facility availability	997	855

Total liquidity	$ 2,715	$ 2,227

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

Credit Ratings

Credit-rating agencies rate a firm 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 the Company 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, 2007:

	S&P	Moody s	Fitch
NRG Energy, Inc.	B+	Ba3	B
7.375% Senior Notes, due 2016, 2017	B	B1	B+
7.25% Senior Notes due 2014	B	B1	B+
Term Loan	BB	Ba1	BB

SOURCES OF FUNDS

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

Financing Arrangements

Senior Credit Facility Amendment

On June 8, 2007, NRG completed a $4.4 billion refinancing of the Company s then existing Senior Credit Facility which comprised a 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 senior first priority secured synthetic letter of credit facility, or the Letter of Credit Facility. The refinancing resulted in a 0.25% reduction on the spread that the Company pays on its Term B loan and Synthetic Letter of Credit Facility, a $200 million reduction in the Synthetic Letter of Credit Facility to $1.3 billion, and various amendments to provide improved flexibility, efficiency for returning capital to shareholders, asset repowering and investment opportunities. The pricing on the Company s Term B loan and Synthetic Letters of Credit Facility was also subject to further reductions upon the achievement of certain financial ratios. The refinancing resulted in a charge of approximately $35 million to the Company s results of operations for the year ended December 31, 2007, which was primarily related to the write-off of previously deferred financing costs.

On August 6, 2007, NRG entered into an agreement with BNP Paribas, or BNP, whereby BNP has agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. BNP has agreed to issue up to $350 million in letters of credit under the revolver. In addition, on January 30, 2008, NRG entered into an agreement with Bank of America, whereby Bank of America has also agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. Bank of America has agreed to issue up to $250 million of letter of credit under the revolver. This increases the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility to $900 million. In addition, NRG is permitted to issue additional letters of credit of up to $100 million under the Senior Credit Facility through other financial institutions.

On December 31, 2007, the Company used cash on hand to prepay, without penalty, $300 million of its Term B loan under the Senior Credit Facility. With this prepayment, the Company has achieved a 3.5:1 threshold for its corporate leverage ratio as defined by its credit agreement, which would result in a 0.25% reduction in the interest rate on both its Term loan B and Synthetic Letter of Credit Facility which is expected to result in approximately $8 million in pre-tax interest savings during 2008. The prepayment will be credited against the Company s mandatory annual prepayment which is required in March 2008 under the Senior Credit Facility. Beginning 2008, NRG must offer a portion of its excess cash flow (as defined in the Senior Credit Facility) to its first lien lenders under the Term B loan. The percentage of excess cash flow offered to these lenders is dependent upon the Company s consolidated leverage ratio (as defined in the Senior Credit Facility) at the end of the preceding year. Of the amount the Company is required to offer, the first lien lenders must accept 50% while the remaining 50% may either be accepted or rejected at the lenders option.

Based on current credit market conditions the Company expects that its lenders will accept in full the mandatory offer required in March 2008, and, as such, the Company has reclassified approximately $146 million of Term Loan B maturity from a non-current to a current liability as of December 31, 2007.

Holdco Credit Facility

During 2007, the Company initiated a capital allocation strategy that contemplated NRG becoming a wholly owned operating subsidiary of a newly created holding company, NRG Holdings, Inc. or Holdco, with the stockholders of NRG becoming stockholders of Holdco. On June 8, 2007, NRG executed a Holdco Credit Facility, a delayed-draw credit facility that expired December 28, 2007, that provided for the funding of $1 billion in term loan financing to Holdco which was intended for Holdco to make a capital contribution to NRG in the amount of $1 billion, to be used to prepay a portion of NRG s existing Term B loan. As part of the commitment, NRG agreed to pay a fee equal to 0.5% of the facility for the first 180 days and 0.75% thereafter.

In November 2007, NRG exercised its right to provide its Senior Note holders with a conditional change of control notice, and related offer to purchase the Company s Senior Notes at 101% of par, prior to the actual formation of the Holdco structure. Concurrently, NRG also sought consent from its Senior Note holders to either waive the change of control or permit additional restricted payments under the indentures. In December 2007, the conditional tender offers and concurrent consent solicitations expired with no tendered Senior Notes accepted for payment and without receipt of the requisite consents to amend the indentures for the Senior Notes. Consequently, the Company decided not to move forward and form the Holdco structure.

First and Second Lien Structure

NRG has granted first and second priority liens to certain counterparties on substantially all of the Company s assets in the United States in order to secure certain obligations, which are primarily long-term in nature under certain power sale agreements and related contracts. NRG uses the first or second lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under these agreements. Within the first and second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties.

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

On October 30, 2007, NRG successfully moved certain second lien holders to a pari passu basis with the Company s first lien lenders effectively releasing $557 million of letters of credit. With the movement to the first lien structure, the Company has significantly reduced its outstanding letter of credit exposure and thereby increased its liquidity. As of December 31, 2007, and February 1, 2008, the net discounted exposure on the agreements and hedges that were subject to the first and second lien structure were approximately $425 million and $340 million, respectively.

In addition, on February 7, 2008, the Company moved an additional counterparty to the first lien position that resulted in an additional return of approximately $65 million in letters of credit.

The following table summarizes the amount of MWs hedged against the Company s baseload assets and as a percentage relative to the Company s forecasted baseload capacity under the first and second lien structure as of February 1, 2008:

Equivalent Net Sales Secured by First and Second Lien Structure[(a)]	**2008**	**2009**	**2010**	**2011**	**2012**
In MW[(b)]	3,283	3,811	3,050	3,264	572
As a percentage of total forecasted baseload capacity	57%	55%	45%	48%	9%

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

(b) 2008 MW value consists of March through December positions only.

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Common Stock Finance I Debt Extension

On February 27, 2008, the Company entered into an arrangement with Credit Suisse that allows the Company, at the Company s option and subject to customary closing conditions, to extend the $220 million notes and preferred interest maturities of CSF I from October 2008 to June 2010. In addition, the previous settlement date for any share price appreciation beyond a 20% compound annual growth rate since the original date of purchase by CSF I, may be extended 30 days to early December 2008. As part of this extension arrangement, the Company intends to contribute to CSF I additional collateral in the form of treasury shares to maintain a blended interest rate of CSF I facility of approximately 7.5%. The Company expects to implement this extension arrangement by March 17, 2008.

Asset Sales

ITISA

On December 18, 2007, NRG entered into a sale and purchase agreement to sell its 100% interest in Tosli, which holds all NRG s interest in ITISA, to Brookfield Power Inc., a wholly-owned subsidiary of Brookfield Asset Management Inc., a Canadian asset management company, focused on property, power and infrastructure assets, for a purchase price of approximately $288 million, plus the assumption of approximately $60 million in debt, subject to purchase price adjustments, the receipt of regulatory approval and other customary closing conditions. NRG anticipates completion of the sale transaction during first half of 2008. As discussed in Note 3, *Discontinued Operations, Business Acquisitions and Dispositions*, the activities of Tosli and ITISA have been classified as discontinued operations.

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) commercial operations activities; (2) capital expenditures including *Repowering*NRG project deposits; (3) corporate financial transactions; and (4) debt service obligations.

Commercial Operations

NRG s commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by (i) margin and collateral posted with counterparties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of December 31, 2007, commercial operations had total cash collateral outstanding of $85 million, and $556 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.

Capital Expenditures

The Company s capital expenditures for the year ended December 31, 2007, increased by approximately $260 million, to $481 million, primarily due to expenditures on *Repowering*NRG projects. The following table

summarizes the Company s capital expenditures for the year ended December 31, 2007, and estimated capital expenditures for 2008:

	Maintenance	Environmental	Repowering	Total
		(In millions)		
Northeast	$ 28	$ 71	$ 7	$ 106
Texas	143	2	45	190
South Central	29	1		30
West	4		76	80
Wind			69	69
Other	6			6
Total	$ 210	$ 74	$ 197	$ 481
Estimated capital expenditures for 2008	$ 234	$ 359	$ 603	$ 1,196

Repowering capital expenditures *Repowering*NRG project capital expenditures consisted of approximately $76 million for the repowered Long Beach generating station and $67 million in deposits for wind turbines related to certain wind farms under development. In addition, the Company s *Repowering*NRG capital expenditures included $7 million for the Cos Cob facility and $45 million for Cedar Bayou Unit 4.

Major maintenance and environmental capital expenditures In 2007, the Company initiated a baghouse project at the Huntley and Dunkirk plants which increased capital expenditures by approximately $71 million. Other capital expenditures included $60 million for STP fuel and maintenance, rotor work of $18 million for the W.A. Parish facility and $7 million related to the Limestone unit 2 facility, $5 million for Indian River unit 4 reheater, Oswego and Arthur Kill spare transformers of $4 million, LaGen Creole Station line rebuild of $4 million and Huntley Unit 67 Boiler replacement of $3 million.

The Company s estimated repowering capital expenditures for 2008 primarily consists of approximately $327 million related to wind farm projects and approximately $172 million related to STP nuclear units 3 and 4. In addition, the Company expects to contribute approximately $83 million in equity towards its joint partnership with BP Alternative Energy North America for the construction of the Sherbino Wind Farm project in Texas.

NRG anticipates funding these maintenance capital projects primarily with funds generated from operating activities. The Company is also pursuing funding for certain environmental expenditures in the Northeast through Solid Waste Disposal Bonds utilizing tax exempt financing, and expects to draw upon such funds during 2008 and 2009.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2008 through 2012 to meet NRG s environmental commitments will be between $1.0 billion and $1.4 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with Clean Air Interstate Rule, or CAIR, the Clean Air Mercury Rule, or CAMR, and related state requirements as well as installation of Best Technology Available under the Phase II 316(b) rule. NRG continues to explore cost effective alternatives that can achieve desired results. The range reflects alternative strategies available with respect to the Company s Indian River plant.

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The following table summarizes the upper end of the estimated range for major environmental capital expenditures for the referenced periods by region:

	Texas	Northeast	South Central	Total
		(In millions)		
2008	$ 3	$ 223	$ 133	$ 359
2009	5	192	211	408
2010	24	178	117	319
2011	28	112	53	193
2012	11	66	15	92
Total	$ 71	$ 771	$ 529	$ 1,371

NRG plans to reduce the impact of a portion of the above environmental capital expenditures. NRG has the ability to monetize a portion of the Company s excess allowances over the 2008 through 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 capital 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.

Share Repurchases

For the year ended December 31, 2007, NRG repurchased 9,044,400 shares of the Company s common stock for approximately $353 million. Of these shares repurchased, 7,006,700 shares of NRG common stock for approximately $268 million were associated with Phase II of the Company s previously announced Capital Allocation Program, which was completed during the third quarter 2007.

In December 2007, the Company initiated its 2008 Capital Allocation Program with the repurchase of 2,037,700 shares of NRG common stock for approximately $85 million. This was followed in January 2008 with the repurchase of 344,000 shares of NRG common stock for approximately $15 million. In February 2008, the Company s Board of Directors authorized an additional $200 million in common share repurchases that would raise the 2008 Capital Allocation Program to approximately $300 million.

RepoweringNRG Project Deposits

NRG has made non-refundable deposits relating to *Repowering*NRG initiatives totaling approximately $71 million primarily towards the procurement of wind turbines. The Company believes that these deposits are necessary for the timely and successful execution of these projects. The deposits are in support of expected deliveries of wind turbines and other equipment totaling approximately $409 million through 2009. Although NRG is committed to their successful implementation, the Company may decide not to take delivery of the equipment and thus terminate the projects. This would result in the Company expensing the deposits it already has made.

On February 4, 2008, NRG through its wholly owned subsidiary, Padoma Wind Power LLC, had entered into a 50-50 joint venture with BP Alternative Energy North America Inc. to build the first phase of the Sherbino Wind Farm. The Sherbino I Wind Farm will be a 150-megawatt (MW) wind project, consisting of 50 Vestas 3 MW wind turbine generators, located approximately 40 miles east of Fort Stockton in Pecos County, Texas. NRG expects to contribute approximately $83 million in equity to the joint venture in 2008 and has posted a letter of credit in that amount.

Preferred Stock Dividend Payments

For the year ended December 31, 2007, NRG paid approximately $28.8 million, $16.8 million and $9.0 million in dividend payments to holders of the Company s 5.75%, 4% and 3.625% Preferred Stock.

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Debt Service Obligations

On December 31, 2007, the Company used cash on hand to prepay, without penalty, $300 million of its Term B loan under the Senior Credit Facility. With this prepayment, the Company has met a financial ratio by the end of 2007 that would result in a 0.25% reduction in the interest rate on both its Term B loan and Synthetic Letter of Credit Facility which is expected to result in approximately $8 million in pre-tax interest savings during 2008. This prepayment will be credited against the Company s mandatory annual prepayment which is required in March 2008 under the Senior Credit Facility.

As of December 31, 2007, NRG had approximately $4.7 billion in aggregate principal amount of unsecured high yield notes or Senior Notes and approximately $2.8 billion in principal amount outstanding under a Term B loan and had issued $743 million of letters of credit under the Company s $1.3 billion Letter of Credit Facility, leaving $557 million available for future issuances. Under the Company s $1.0 billion Revolving Facility, as of December 31, 2007, NRG had issued $3 million in letters of credit, leaving $997 million available for borrowings, of which approximately $647 million could be used to issue additional letters of credit. As of February 15, 2008, $518 million of undrawn letters of credit remain available under the funded letter of credit facility, $897 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.

In November 2007 NRG made a payment of $11 million on a revolving note after Merrill Lynch put the note back to the Company.

Principal payments on debt and capital leases as of December 31, 2007 are due in the following periods:

Subsidiary/Description	**2008**	**2009**	**2010**	**2011**	**2012**	**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	184	31	32	31	31	2,506	2,815
CSF Non-Recourse Obligations	190	143					333
NRG Energy Center Minneapolis, due 2013 and 2017	10	11	11	12	13	37	94
NRG Peaker Finance Co LLC	13	15	20	21	22	188	279
Subtotal Debt, Bonds and Notes	397	200	63	64	66	7,431	8,221
Capital Lease:							
Saale Energie GmbH, Schkopau	75	26	12	6	5	57	181
Total Payments and Capital Leases	$ 472	$ 226	$ 75	$ 70	$ 71	$ 7,488	$ 8,402

Cash Flow Discussion

NRG obtains cash from operations, proceeds from the sale of assets as well as 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.

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2007 compared to 2006

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,	**2007**	**2006**	**Change**
		(In millions)	
Net cash provided by operating activities	$ 1,517	$ 408	$ 1,109
Net cash provided/(used) by investing activities	(327)	(4,176)	3,849
Net cash provided/(used) by financing activities	(814)	4,053	(4,867)

Net Cash Provided By Operating Activities

For the year ended December 31, 2007, net cash provided by operating activities increased by $1.1 billion compared to the same period in 2006. This was due to:

Hedge Reset and derivative activity this increase was primarily due to the write off of power contracts of $1.1 billion in the fourth quarter of 2006 and a corresponding $339 million reduction in contract amortization during 2007 compared to 2006 as a result of the Hedge Reset transaction. In addition, net income increased $226 million as a result of adjustments for derivative activity.

Collateral deposits following an upward shift of the forward price curves, NRG s net collateral deposits in support of derivative contracts increased by $125 million for the year ended December 31, 2007, compared to a decrease of $454 million during the same period in 2006, a difference of $579 million. As of December 31, 2007, NRG had net cash collateral deposit of $85 million.

Net Cash Used in Investing Activities

For the year ended December 31, 2007, net cash used in investing activities was approximately $3.9 billion less than the same period in 2006. This reduction in investing activities was due to:

Texas acquisition that occurred during the first quarter 2006. NRG acquired Texas Genco LLC for approximately $6.2 billion that included the issuance of common stock at a value of $1.7 billion and a net cash payment of approximately $4.3 billion;

Capital expenditures NRG s capital expenditures increased by $260 million due to expenditures of approximately $197 million for *Repowering*NRG projects, primarily related to $76 million for the Long Beach plant and $67 million in deposits for wind turbines. In addition, the Company initiated a baghouse project at the Huntley and Dunkirk plants which also increased capital expenditures by approximately $71 million.

Discontinued Operations and Asset Sales In 2006 NRG received proceeds of $261 million from the sale of Flinders, Audrain, and Resource Recovery. The sale of the Company s Red Bluff and Chowchilla plants and equipment resulted in increased proceeds from asset sales by approximately $57 million for 2007.

Net Cash Provided/(Used) in Financing Activities

For the year ended December 31, 2007, net cash used in financing activities decreased by approximately $4.9 billion compared to 2006, due to:

During the first quarter 2006, NRG acquired Texas Genco LLC. As part of the acquisition, NRG refinanced the Company s outstanding debt as well as Texas Genco LLC s outstanding debt, and also issued new debt, preferred stock and common stock to fund the acquisition:

Total debt repayments were $4.6 billion $1.9 billion of NRG debt and $2.7 billion of Texas Genco LLC debt.

Total proceeds from debt issued were $7.2 billion $3.6 billion from unsecured notes and $3.6 billion from a senior secured facility, including a $1.0 billion Revolving Credit Facility, and a $1.5 billion Synthetic Letter of Credit Facility.

Total proceeds from stock issued of approximately $1.5 billion - net proceeds of $986 million from issuing approximately 21 million shares of common stock and net proceeds of $486 million from issuing 2 million shares of the Company s 5.75% Preferred Stock.

For the year ended December 31, 2007, NRG repurchased 9,049,400 shares of the Company s common stock for approximately $353 million. For the year ended December 31, 2006, NRG repurchased 29,601,162 shares for $732 million. The Company also used cash on hand to repay, without penalty, $300 million of its Term B loan under the Senior Credit Facility.

NOL s, Deferred Tax Assets and FIN 48 Implications

As of December 31, 2007, the Company had generated total domestic pretax book income of $860 million which fully utilized domestic NOL in the amount of $245 million. In addition, NRG has cumulative foreign NOL carryforwards of $288 million, of which $72 million will expire starting in 2011 through 2016 and of which $216 million do not have an expiration date.

In addition to these amounts, the Company has $683 million of tax effected unrecognized tax benefits which relate primarily to net operating losses for tax return purposes but have been classified as capital loss carryforwards for financial statements purposes and for which a full valuation allowance has been established. As a result of the Company s tax position, and based on current forecasts, future U.S. domestic income tax payments will be minimal through mid-year 2009 as these unrecognized tax benefits will be utilized for tax return purposes.

However, as the position remains uncertain, of the $683 million of tax effected unrecognized tax benefits, the Company has recorded a non-current tax liability of $7 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority.

On July 6, 2007, the German government passed the Tax Reform Act of 2008, which reduces the German statutory and resulting effective tax rates on earnings from approximately 36% to approximately 27% effective January 1, 2008. Due to this reduction in the statutory and resulting effective tax rate in 2007, NRG recognized a $29 million tax benefit and as of December 31, 2007, NRG had a German net deferred tax liability of approximately $84 million which includes the impact of this tax rate change.

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.

Retained or Contingent Interests

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

Derivative Instrument obligations

On August 11, 2005, NRG issued 3.625% Preferred Stock that includes a feature which is considered an embedded derivative per SFAS 133. Although it is considered an embedded derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of SFAS 133. As of December 31, 2007, based on the Company s stock price, the redemption value of this embedded derivative was approximately $151 million.

On October 13, 2006, NRG through its unrestricted wholly-owned subsidiaries NRG Common Stock Fund I and NRG Common Stock Fund II, issued notes and preferred interests for the repurchase of NRG s common stock. Included in the agreement is a feature which is considered an embedded derivative per SFAS 133. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of SFAS 133. As of December 31, 2007, based on the Company s stock price, the redemption value of this embedded derivative was approximately $87 million.

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Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments As of December 31, 2007, NRG had not entered into any financing structure that was designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to the Company. However, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy-related entities that are accounted for under the equity method of accounting. NRG s pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $122 million as of December 31, 2007. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG.

Synthetic Letter of Credit Facility and Revolver Facility Under NRG s amended Senior Credit Facility which the company entered in to on June 8, 2007, the Company has a $1.3 billion synthetic Letter of Credit Facility which is secured by a $1.3 billion cash deposit at Deutsche Bank AG, New York Branch, the Issuing Bank. This deposit was funded using proceeds from the Term B loan investors who participated in the facility syndication. Under the Synthetic Letter of Credit Facility, NRG is allowed to issue letters of credit for general corporate purposes including posting collateral to support the Company s commercial operations activities. On August 6, 2007, NRG entered into an agreement with BNP Paribas, or BNP, whereby BNP has agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. BNP has agreed to issue up to $350 million of letters of credit. In addition, on January 30, 2008, NRG entered into an agreement with Bank of America, whereby Bank of America has also agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. Bank of America has agreed to issue up to $250 million of letters of credit under the revolver. This increases the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility to $900 million for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the Senior Credit Facility. In addition, NRG is permitted to issue additional letters of credit of up $100 million under the Senior Credit facility through other financial institutions.

As of December 31, 2007, the Company had issued $743 million in letters of credit under the Synthetic Letter of Credit Facility. In addition, as of December 31, 2007, the Company had issued $3 million in letters of credit under the Revolving Credit Facility. A portion of these letters of credit supports non-commercial letter of credit obligations.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company s capital expenditure programs. 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.

	By Remaining Maturity at December 31, 2007					
Contractual Cash Obligations	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total**	**2006 Total**
	(In millions)					
Long-term debt (including estimated interest)	$ 1,010	$ 1,407	$ 1,263	$ 8,621	$ 12,301	$ 13,348
Capital lease obligations (including estimated interest)	93	66	28	203	390	403
Operating leases	40	73	64	243	420	427
	1,614	1,059	299	231	3,203	3,646

Fuel purchase and transportation obligations[(a)]												
Total contractual cash obligations	$	2,757	$	2,605	$	1,654	$	9,298	$	16,314	$	17,824

(a) Includes only those coal transportation commitments for 2008 as no other nominations were made as of December 31, 2007.

Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2006 Total
	By Remaining Maturity at December 31, 2007 (In millions)					
Synthetic letters of credit	$ 475	$ 268	$	$	$ 743	$ 967
Unfunded standby letters of credit and surety bonds	8				8	153
Asset sales guarantee obligations	13		113	22	148	144
Commodity sales guarantee obligations	93	134		564	791	604
Other guarantees				32	32	29
Total guarantees	$ 589	$ 402	$ 113	$ 618	$ 1,722	$ 1,897

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 2007.

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, 2007, based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2007.

Derivative Activity Gains/(Losses)

Derivative Activity Gains/(Losses)	(In millions)
Fair value of contracts as of December 31, 2006	$ 354
Contracts realized or otherwise settled during the period	(292)
Changes in fair value	(554)

Fair value of contracts as of December 31, 2007	$ (492)

	Fair Value of Contracts as of December 31, 2007				
Sources of Fair Value Gains/(Losses)	**Maturity Less Than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in Excess 4-5 Years**	**Total Fair Value**
			(In millions)		
Prices actively quoted	$ 4	$ 2	$	$	$ 6
Prices provided by other external sources	89	(198)	(394)	(22)	(525)
Prices provided by models and other valuation methods	23	2	2		27
Total	$ 116	$ (194)	$ (392)	$ (22)	$ (492)

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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	**Judgments/Uncertainties Affecting Application**
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

Accounting Policy	Judgments/Uncertainties Affecting Application
	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, 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, 2007, NRG had a valuation allowance of approximately $539 million. This amount is comprised of U.S. domestic capital loss carryforwards and non-depreciable property of approximately $458 million, foreign net operating loss carryforwards of approximately $80 million and foreign capital loss carryforwards of approximately $1 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, 2007, NRG had fully utilized $245 million of cumulative U.S. federal and state net operating loss 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. NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including major operations located in Germany, Australia, and Brazil. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2002. With few exceptions, state and local income tax examinations are no longer open for years before 2003. The Company s significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2000.

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 certain 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

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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 holds 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, 2007, there was a reduction of $11 million in income from continuing operation due to an impairment of an investment in commercial paper which has been subsequently reclassified from cash equivalents to non-current assets. The Company recorded this impairment as a reduction to interest income. For the year ended 2006, there was no reduction in income from continuing operation due to any impairment. For the year ended December 31, 2005, income from continuing operations was reduced by $6 million due to an impairment.

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 impairments 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 with indefinite lives 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 net negative fair values at the closing date of the acquisition and were reflected as assumed contracts in the consolidated balance sheets. 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 Policies,* 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 uses various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets to:

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

Commodity Price Risk

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

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

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

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

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

NRG uses a diversified VAR model to calculate an estimate of the potential loss in the fair value of the Company s energy assets and liabilities, which includes generation assets, load obligations, and bilateral physical and financial transactions. The key assumptions for the Company s diversified model include: (1) a lognormal distribution of prices, (2) one-day holding period, (3) a 95% confidence interval, (4) a rolling 36-month forward looking period, and (5) market implied volatilities and historical price correlations.

As of December 31, 2007, the VAR for NRG s commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VAR model was $64 million.

The following table summarizes average, maximum and minimum VAR for NRG for the year ended December 31, 2007 and 2006:

VAR	In millions	
As of December 31, 2007[b]	$	64
Average		28
Maximum		64
Minimum		14
As of December 31, 2006	$	18
Average[a]		39
Maximum[a]		67
Minimum[a]		17

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

(b) Prior to December 4, 2007, NRG s VAR measurement was based on a rolling 24-month forward looking period

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

In order to provide additional information for comparative purposes to NRG s peers, the Company also uses VAR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VAR for the derivative financial instruments calculated using the diversified VAR model as of December 31, 2007, for the entire term of these instruments entered into for both asset management and trading was approximately $17 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, 2007 was $2.03 billion.

The notional amounts and maturities of each tranche of these swaps are as follows:

Period of Swap	**Notional Value**	**Maturity**
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, 2007, the Company had various interest rate swap agreements, including those listed above, with notional amounts totaling approximately $2.7 billion. If the swaps had been discontinued on December 31, 2007, the Company would have owed the counter-parties approximately $69 million. Based on

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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, 2007, a 100 basis point change in interest rates would result in a $16 million change in interest expense on a rolling twelve month basis.

As of December 31, 2007, the Company s long-term debt fair value was $8.1 billion and the carrying amount was $8.4 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 $471 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 $15 million as of December 31, 2007. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2007.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages the credit risk of NRG and its subsidiaries through credit policies 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, 2007, NRG held net collateral of approximately $147 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 the balance sheet settlement exposures related to these activities as of December 31, 2007:

Exposure

Credit Exposure	**Before Collateral**	**Collateral**	**Net Exposure**
	(In millions, except ratios)		
Investment grade	$ 1,446	$ 464	$ 982
Non-investment grade	39	9	30
Not rated	171	11	160
Total	$ 1,656	$ 484	$ 1,172
Investment grade	87%	96%	84%
Non-investment grade	2%	2%	3%
Not rated	10%	2%	14%

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

NRG s exposure to significant counterparties greater than 10% of the net exposure of approximately $1.2 billion, was $923 million as of December 31, 2007. NRG does not anticipate any material adverse effect on the Company s financial position or results of operations as a result of nonperformance by any of NRG s counterparties.

Currency Exchange Risk

NRG may be subject to foreign currency risk as a result of the Company entering into purchase commitments with foreign vendors for the purchase of major equipment associated with *Repowering*NRG initiatives. To reduce the risks to such foreign currency exposure, the Company may enter into transactions to hedge its foreign currency exposure using currency options and forward contracts. At December 31, 2007, no foreign currency options and forward contracts were outstanding. As a result of the Company s limited foreign currency exposure to date, the effect of foreign currency fluctuations has not been material to the Company s results of operations, financial position and cash flows.

The effects of a hypothetical simultaneous 10% appreciation in the U.S. dollar from year-end 2007 levels against all other currencies of countries in which the Company has continuing operations 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 $55 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. Management s report on the Company s internal control over financial reporting and the report of the Company s independent registered public accounting firm are incorporated under the caption Management s Report on Internal Control over Financial Reporting and under the caption Report of Independent Registered Public Accounting Firm, of the Company s 2007 Annual Report to Shareholders.

Changes in Internal Control Over Financial Reporting

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, 2007 that have materially affected, or are reasonably likely to materially affect the Company s internal control over financial reporting.

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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*

Management Restructuring Having experienced significant financial, organizational and operational growth since emerging from bankruptcy in 2003, NRG will implement several enhancements to the Company s management structure in order to better position the Company to capitalize on gains made already through initiatives such as *Repowering*NRG and *FOR*NRG and to support the future growth of the Company. These developments, effective as of March 1, are as follows:

Robert Flexon has been promoted to the newly created position of Chief Operating Officer. Mr. Flexon will now oversee NRG s Plant Operations, Commercial Operations, Environmental Compliance and Risk teams, as well as the Engineering, Procurement and Construction division. Since March 2004, he has served as the Company s Chief Financial Officer. Prior to joining NRG, from June 2000 to March 2004, Mr. Flexon was Vice President, Corporate Development & Work Process and Vice President, Business Analysis and Controller of Hercules, Inc.

Clint Freeland, NRG s Treasurer since April 2006, has been promoted to Chief Financial Officer. Mr. Freeland will now manage the Company s corporate financial and control functions including Treasury, Accounting, Tax and Insurance programs. Mr. Freeland joined NRG in July, 2004 as Director, Finance, following over 10 years in key financial roles within the energy sector for such Houston-based companies as Enron, Coral Energy and ABN AMRO Bank, N.V.

In addition, Kevin Howell has been promoted to NRG s Chief Administrative Officer. In this position, Mr. Howell will oversee several critical corporate functions including Communications, Investor Relations, Human Resources and Information Technology. Previously, Mr. Howell led NRG s Commercial Operations group, a position he held since August 2005. Prior to joining NRG, he served as President of Dominion Energy Clearinghouse since 2001.

Mauricio Gutierrez will be promoted and will succeed Mr. Howell as Senior Vice President, Commercial Operations. Mr. Gutierrez currently serves as Vice President, Commercial Operations Trading where he is responsible for the trading operations and will now expand his responsibilities to include the real time operations, origination and structuring for the Company. Mr. Gutierrez joined NRG in August 2004.

In addition, Carolyn Burke, Vice President and Controller, will be resigning from the Company effective March 14, 2008. James Ingoldsby, currently serving as Vice President, Financial Planning and Analysis, will assume Ms. Burke s responsibilities in his new position as Vice President and Chief Accounting Officer effective March 1, 2008. In this role, Mr. Ingoldsby is responsible for directing NRG s financial accounting and reporting activities, as well as the financial planning and analysis function. Since August 2006, Mr. Ingoldsby served as Vice President, Financial Planning and Analysis. From May 2004 to July 2006, Mr. Ingoldsby served as NRG s Vice President and Controller. Mr. Ingoldsby, who led the Sarbanes-Oxley implementation at chemical company Hercules, Inc., previously held various executive positions at GE Betz, formerly BetzDearborn from 1993 to 2003, including serving as Controller, and Director of Business Analysis and Director of Financial Reporting. He also held various staff and managerial accounting and auditing positions at Mack Trucks, Inc. from 1982 to 1993. Mr. Ingoldsby began his career with Deloitte and Touche.

The compensation arrangements for the Company s named executive officers, as well as Mr. Freeland, are filed as Exhibit 10.33 to this Form 10-K and incorporated herein by reference.

Amendment to Bylaws On February 26, 2008, the Board of Directors of the Company unanimously approved an amendment to Article VI, Sections 1 and 2, of NRG s Amended and Restated Bylaws effective immediately. The amended provision allows the Board, by resolution, to provide for uncertificated shares of common stock to be evidenced by a book-entry system, as well as other conforming changes. The Board also approved amendments to Article V to clarify that employees of NRG who serve as officers or directors of joint ventures are entitled to the same indemnification rights as officers or directors of wholly-owned NRG subsidiaries. A complete copy of the Amended and Restated Bylaws is filed as Exhibit 3.2 to this Form 10-K and incorporated herein by reference.

CSF I Extension On February 27, 2008, NRG Common Stock Finance I LLC, or CSF I, a wholly owned subsidiary of the Company, entered into an amendment to the Note Purchase Agreement by and among CSF I, Credit Suisse International and Credit Suisse Securities (USA) LLC, as agent, dated August 4, 2006 and an amendment to the Preferred Interest Agreement by and among CSF I, Credit Suisse International and Credit Suisse Securities (USA) LLC, as agent, dated August 4, 2006. The arrangement with Credit Suisse allows the Company, at the Company s option and subject to customary closing conditions, to extend the $220 million notes and preferred interest maturities of CSF I from October 2008 to June 2010. In addition, the previous settlement date for any share price appreciation beyond a 20% compound annual growth rate since the original date of purchase by CSF I, may be extended 30 days to early December 2008. As part of this extension arrangement, the Company intends to contribute to CSF I additional collateral in the form of treasury shares to maintain a blended interest rate of CSF I facility of approximately 7.5%. The Company expects to implement this extension arrangement by March 17, 2008.

PART III

Item 10 *Directors, Executive Officers and Corporate Governance*

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 2008 Annual Meeting of Stockholders to be held May 14, 2008.

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 2008 Annual Meeting of Stockholders to be held May 14, 2008.

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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 2008 Annual Meeting of Stockholders to be held May 14, 2008.

Item 13 ***Certain Relationships and Related Transactions, and Director Independence***

Other information required by this Item will be incorporated by reference to the similarly named section of NRG s definitive Proxy Statement for its 2008 Annual Meeting of Stockholders to be held May 14, 2008.

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 2008 Annual Meeting of Stockholders to be held May 14, 2008.

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, 2007, 2006 and 2005

Consolidated Balance Sheet December 31, 2007 and 2006

Consolidated Statement of Cash Flows Years ended December 31, 2007, 2006 and 2005

Consolidated Statement of Stockholders Equity and Comprehensive Income/(Loss) Years ended December 31, 2007, 2006 and 2005

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.

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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, 2007.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2007 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.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited NRG Energy Inc. s internal control over financial reporting as of December 31, 2007, 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, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, NRG Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2007 and 2006, 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, 2007, and our report dated February 28, 2008, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2008

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, 2007 and 2006, 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, 2007. In connection with our audits of the consolidated financial statements, we also have audited 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, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, 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 Issue 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 2 to the consolidated financial statements, the Company also adopted SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of SFAS No. 87, 88, 106, and 132(R)*, effective December 31, 2006. As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of SFAS No. 109*, on January 1, 2007.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), NRG Energy, Inc. s internal control over financial reporting as of December 31, 2007, 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, 2008 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2008

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006	For the Year Ended December 31, 2005
	(In millions except per share amounts)		
Operating Revenues			
Total operating revenues	$ 5,989	$ 5,585	$ 2,400
Operating Costs and Expenses			
Cost of operations	3,378	3,265	1,829
Depreciation and amortization	658	590	158
General and administrative	309	276	176
Development costs	101	36	
Other charges			12
Total operating costs and expenses	4,446	4,167	2,175
Gain on sale of assets	17		
Operating Income	1,560	1,418	225
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	54	60	104
Write downs and gains/(losses) on sales of equity method investments	1	8	(31)
Other income, net	55	156	54
Refinancing expenses	(35)	(187)	(65)
Interest expense	(689)	(590)	(177)
Total other expenses	(614)	(553)	(115)
Income From Continuing Operations Before Income Taxes	946	865	110
Income tax expense	377	322	42
Income From Continuing Operations	569	543	68
Income from discontinued operations, net of income taxes	17	78	16
Net Income	586	621	84
Preference stock dividends	55	50	20
Income Available for Common Stockholders	$ 531	$ 571	$ 64

Weighted average number of common shares outstanding basic		240		258		169
Income from continuing operations per weighted average common share basic	$	2.14	$	1.90	$	0.28
Income from discontinued operations per weighted average common share basic		0.07		0.31		0.10
Net Income per Weighted Average Common Share Basic	$	2.21	$	2.21	$	0.38
Weighted average number of common shares outstanding diluted		288		301		171
Income from continuing operations per weighted average common share diluted	$	1.95	$	1.78	$	0.28
Income from discontinued operations per weighted average common share diluted		0.06		0.26		0.10
Net Income per Weighted Average Common Share Diluted	$	2.01	$	2.04	$	0.38

See notes to Consolidated Financial Statements

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,132	$ 777
Restricted cash	29	41
Accounts receivable trade, less allowance for doubtful accounts of $1 and $1	482	369
Current portion of capital lease	30	27
Taxes receivable	58	63
Inventory	451	420
Derivative instruments valuation	1,034	1,230
Deferred income taxes	124	
Collateral on deposits in support of energy risk management activities	85	27
Prepayments and other current assets	86	105
Current assets discontinued operations	51	24
Total current assets	3,562	3,083
Property, Plant and Equipment		
In service	12,678	12,433
Under construction	337	87
Total property, plant and equipment	13,015	12,520
Less accumulated depreciation	(1,695)	(974)
Net property, plant and equipment	11,320	11,546
Other Assets		
Equity investments in affiliates	425	344
Note receivable affiliates	126	114
Capital lease, less current portion	365	365
Goodwill	1,786	1,789
Intangible assets, net of accumulated amortization of $372 and $259	873	981
Nuclear decommissioning trust fund	384	352
Derivative instruments valuation	150	439
Other non-current assets	176	262
Intangible assets held-for-sale	14	79
Non-current assets discontinued operations	93	82
Total other assets	4,392	4,807

Total Assets	$	19,274	$	19,436

See notes to Consolidated Financial Statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	As of December 31, 2007	As of December 31, 2006
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 466	$ 123
Accounts payable trade	381	327
Accounts payable affiliates	3	2
Derivative instruments valuation	917	964
Deferred income taxes		164
Accrued interest expense	185	131
Other accrued expenses	189	130
Other current liabilities	99	163
Current liabilities discontinued operations	37	28
Total current liabilities	2,277	2,032
Other Liabilities		
Long-term debt and capital leases	7,895	8,603
Nuclear decommissioning reserve	307	289
Nuclear decommissioning trust liability	326	324
Postretirement and other benefit obligations	263	301
Deferred income taxes	843	554
Derivative instruments valuation	759	351
Out-of-market contracts	628	897
Other non-current liabilities	149	116
Non-current liabilities discontinued operations	76	64
Total non-current liabilities	11,246	11,499
Total Liabilities	13,523	13,531
3.625% convertible perpetual preferred stock; $0.01 par value; 250,000 shares issued and outstanding (at liquidation value of $250, net of issuance costs)	247	247
Commitments and Contingencies		
Stockholders Equity		
4% convertible perpetual preferred stock; $0.01 par value; 420,000 shares issued and outstanding (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 liquidation value of $500, net of issuance costs)		486		486
Common Stock; $0.01 par value; 500,000,000 shares authorized; 261,285,529 and 274,248,264 shares issued and 236,734,929 and 244,647,102 outstanding at December 31, 2007 and 2006		3		3
Additional paid-in-capital		4,092		4,474
Retained earnings		1,270		739
Less treasury stock, at cost 24,550,600 and 29,601,162 shares at December 31, 2007 and 2006		(638)		(732)
Accumulated other comprehensive (loss)/income		(115)		282
Total Stockholders Equity		5,504		5,658
Total Liabilities and Stockholders Equity	$	19,274	$	19,436

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 Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockhold Equity
					(In millions)				
ances at December 31, 4	$ 406	0.4	$ 3	174	$ 2,415	$ 197	$ (405)	$ 76	$ 2,6
income						84			
eign currency translation stments								(72)	(
ealized loss on vatives								(203)	(2
imum pension liability, of $3 tax								(6)	
nprehensive loss for 5									(1
ity-based compensation					14				
erred stock dividends						(20)			(
chase of treasury stock				(13)			(258)		(2
ances at December 31, 5	$ 406	0.4	$ 3	161	$ 2,429	$ 261	$ (663)	$ (205)	$ 2,2
income						621			6
eign currency translation stments								60	
ealized gain on vatives, net of $135 tax								405	4
imum pension liability, of $3 tax								7	
nprehensive income for 6									1,0
act upon adoption of S 158, net of $10 tax								15	
uction to tax valuation wance					17				
act upon adoption of F 04-6						(93)			(
ity-based compensation					14				
				42	986				9

ance of common stock e public									
ance of preferred stock	486	2.0							4
ance of common and sury stock to the eholders of Texas co LLC				71	1,028		663		1,6
erred stock dividends						(50)			(
chase of treasury stock				(29)			(732)		(7
ances at December 31, 6	$ 892	2.4	$ 3	245	$ 4,474	$ 739	$ (732)	$ 282	$ 5,6
income						586			5
eign currency translation stments								73	
ealized loss on vatives, net of $310 tax efit								(474)	(4
ilable-for-sale rities, net of $1 tax								2	
ned benefit plan prior ice cost of $4 and net of $(2), net of $2 tax								2	
nprehensive income for 7									1
ity-based compensation				1	9				
uction to tax valuation wance					56				
erred stock dividends						(55)			(
chase of treasury stock				(9)			(353)		(3
rement of treasury stock					(447)		447		
ances at December 31, 7	$ 892	2.4	$ 3	237	$ 4,092	$ 1,270	$ (638)	$ (115)	$ 5,5

See notes to Consolidated Financial Statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In millions)	
Cash Flows from Operating Activities			
Net income	$ 586	$ 621	$ 84
Adjustments to reconcile net income to net cash provided by operating activities			
Distributions less than equity in earnings of unconsolidated affiliates	(33)	(33)	(8)
Depreciation and amortization of nuclear fuel	719	654	195
Amortization and write-off of deferred financing costs and debt discount/premiums	66	79	14
Amortization of intangibles and out-of-market contracts	(156)	(490)	17
Amortization of equity-based compensation	19	14	12
Write down and (gains)/losses on sale of equity method investments	(1)	(8)	31
(Gain)/loss on sale and disposal of equipment	(17)	10	4
Impairment charges and asset write downs	20		6
Changes in derivatives	77	(149)	143
Changes in deferred income taxes	352	327	2
Gain on legal settlement		(67)	(14)
Gain on sale of discontinued operations		(76)	(6)
Gain on sale of emission allowances	(31)	(64)	
Change in nuclear decommissioning trust liability	32	12	
Changes in collateral deposits supporting energy risk management activities	(125)	454	(405)
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	(102)	87	(8)
Inventory	(38)	(50)	(14)
Prepayments and other current assets	22	43	(35)
Accounts payable	49	(73)	57
Accrued expenses and other current liabilities	106	133	(16)
Other assets and liabilities	(28)	57	9
Net Cash Provided by Operating Activities	1,517	408	68
Cash Flows from Investing Activities			
		(4,333)	(5)

Acquisition of Texas Genco LLC, WCP and Padoma , net of cash acquired			
Capital expenditures	(481)	(221)	(106)
Decrease in restricted cash, net	12	6	45
Decrease in notes receivable	34	27	107
Decrease in trust fund balances	19		
Purchases of emission allowances	(161)	(135)	
Proceeds from sale of emission allowances	272	146	
Investments in nuclear decommissioning trust fund securities	(265)	(227)	
Proceeds from sales of nuclear decommissioning trust fund securities	233	214	
Proceeds from sale of investments and equipment	2	86	79
Purchases of securities	(49)		
Proceeds from sale of discontinued operations and assets	57	260	36
Return of capital from equity method investments		1	2
Net Cash Provided/(Used) by Investing Activities	(327)	(4,176)	158
Cash Flows from Financing Activities			
Payment of dividends to preferred stockholders	(55)	(50)	(20)
Payment of financing element of acquired derivatives		(296)	
Payment for treasury stock	(353)	(732)	(250)
Payment of minority interest obligations			(4)
Funded letter of credit		350	
Proceeds from issuance of common stock, net of issuance costs	7	986	
Proceeds from issuance of preferred shares, net of issuance costs		486	246
Proceeds from issuance of long-term debt	1,411	8,619	249
Payment of deferred debt issuance costs	(5)	(199)	(46)
Payments for short and long-term debt	(1,819)	(5,111)	(1,005)
Net Cash Provided/(Used) by Financing Activities	(814)	4,053	(830)
Change in cash from discontinued operations	(25)	2	37
Effect of exchange rate changes on cash and cash equivalents	4	4	(2)
Net Increase/(Decrease) in Cash and Cash Equivalents	355	291	(569)
Cash and Cash Equivalents at Beginning of Period	777	486	1,055
Cash and Cash Equivalents at End of Period	$ 1,132	$ 777	$ 486

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 engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets.

As of December 31, 2007, NRG had a total portfolio of 191 active operating generation units at 49 power generation plants, with an aggregate generation capacity of approximately 24,115 MW. Within the United States, NRG has a power generation portfolio of approximately 22,880 MW of generation capacity in 175 active generating units at 43 plants, primarily located in the Texas or ERCOT region (approximately 10,805 MW), the Northeast (approximately 6,980 MW), South Central (approximately 2,850 MW), and West (approximately 2,130 MW) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets.

NRG 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 VIE s, 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.

As discussed in Note 14, *Investments Accounted for by the Equity Method*, NRG also has investments in partnerships, joint ventures and projects.

Accounting policies for all of NRG s operations are in accordance with accounting principles generally accepted in the United States of America. Upon its emergence from bankruptcy on December 5, 2003, the Company qualified for and adopted fresh start reporting, or Fresh Start, under Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments 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 is 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 as incurred, 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.

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 or disposal groups 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 or disposal group, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. In addition, upon completion of the transaction, the operations and cash flows of the disposal group must be eliminated from ongoing operations of the Company, and the disposal group must not

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

have any significant continuing involvement with the Company. 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, 2007.

Goodwill

In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*, or SFAS 142, 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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes

NRG accounts for income taxes using the liability method in accordance with SFAS No. 109, *Accounting for Income Taxes*, or SFAS 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.

In January 2007, the Company adopted 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. The Company recognizes interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense.

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 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, or EITF 02-3.*

Capacity Capacity revenues are recognized when contractually earned, and consist 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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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.

Effective July, 1, 2007, the Company adopted the Emerging Issues Task Force, or EITF, Topic D-109, *Determining the Nature of a Host Contract Related to a Hybrid Financial Instrument Issued in the Form of a Share under FASB Statement No. 133.* This Topic conveys the SEC staff s views on determining whether the characteristics of a host contract in a hybrid financial instruments issued in the form of a share is more like debt or equity. The SEC staff believes that in evaluating an embedded derivative feature for separation under FASB Statement 133, the consideration of the economic characteristics and risks of the host contract should not ignore the stated or implied substantive terms and features of the hybrid financial instrument. The adoption of Topic D-109 did not have an impact on the Company s, results of operations, financial position or cash flows.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, 2006 and 2005, 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 and cash equivalents are held at financial institutions with high credit ratings. Trust funds are held in accounts managed by experienced investment advisors. 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 4, *Financial Instruments.* The fair value of long-term debt is based on quoted market prices for those instruments that are publicly traded, or estimated based on the income approach valuation technique for non-publicly traded debt. During the fourth quarter 2007, the Company recorded an $11 million impairment charge related to an investment in commercial paper reducing its carrying value to approximately $32 million.

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 FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, or 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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

storage facilities. See Note 6, *Nuclear Decommissioning Trust Fund,* 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, 2007 and 2006, along with the additions, reductions and accretion related to the Company s asset retirement obligation for the year ended December 31, 2007:

	Total (In millions)
Balance as of December 31, 2006	$ 381
Additions	4
Reduction	(1)
Accretion Expense	7
Accretion Other	18
Balance as of December 31, 2007	$ 409

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. Forfeiture rates are estimated based on an analysis of NRG s historical forfeitures, employment turnover, and expected future behavior. 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.

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. MIBRA GmbH, or MIBRAG, in which NRG holds a 50% equity investment, has mining operations which were 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. 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.

Stock Split

On April 25, 2007, NRG s Board of Directors approved a two-for-one stock split of the Company s outstanding shares of common stock which was effected through a stock dividend. The stock split entitled each

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stockholder of record at the close of business on May 22, 2007 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed by the Company s transfer agent on May 31, 2007. All share and per share amounts within this document retroactively reflect the effect of the stock split.

Recent Accounting Developments

In September 2006, the Financial Accounting Standards Board, or 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. In February 2008, the FASB issued FASB Staff Position, or FSP, No. FAS 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*, which amends SFAS 157 to exclude FASB Statement No. 13, *Accounting for Leases*, or SFAS 13, and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB also issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which permitted delayed application of this statement for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. NRG partially adopted SFAS 157 on January 1, 2008, delaying application for nonfinancial assets and nonfinancial liabilities as permitted. This partial adoption of SFAS 157 did not have a material impact on the Company s consolidated financial position, statement of operations, and cash flows. The Company is currently evaluating the impact of the deferred portion of SFAS 157 on the Company s consolidated financial position, statement of operations, and 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. As of the January 1, 2008 effective date, the Company elected not to apply this standard to any of its existing eligible assets or liabilities; therefore there was no impact on NRG s consolidated financial position, results of operations, or cash flows.

In April 2007, FASB issued its Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39*, or FSP FIN 39-1, which amends FIN 39, *Offsetting of Amounts Related to Certain Contracts*. FSP FIN 39-1 impacts entities that enter into master netting arrangements as part of their derivative transactions. Under the guidance in this new FSP, entities may choose to offset derivative positions in the financial statements against the fair value of amounts recognized as cash collateral paid or received under those arrangements. As of the January 1, 2008 effective date, the Company elected not to apply this FSP to any of its existing eligible derivative positions; therefore there was no impact on NRG s consolidated financial position, results of operations, or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*, or SFAS 141(R). This statement applies prospectively to all business combinations for which the acquisition date is on or after the beginning of an entity s first annual reporting period beginning on or after December 15, 2008. The statement establishes principles and requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any minority interest in the acquiree at fair value. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity s financial statements to evaluate the nature and financial effects of the business combination. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, Consolidated Financial Statements*, or SFAS 160. This Statement amends ARB No. 51 to establish accounting and reporting standards for the minority interest in a subsidiary and for the deconsolidation of a subsidiary. It also amends certain of ARB No. 51 s consolidation procedures for consistency with the requirements of SFAS 141(R). This Statement shall be effective and applied prospectively for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008, except for the presentation and disclosure requirements, which shall be applied retrospectively. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

NRG has non-qualified stock options for which it estimates the expected term using the simplified method allowed under Staff Accounting Bulletin (SAB) No. 107, *Share Based Payment*, or SAB 107. In December 2007, the SEC issued SAB No. 110, *Certain Assumptions Used in Valuation Methods*, which eliminates the December 31, 2007 expiration of SAB 107 s permission to use this simplified method. NRG will therefore continue to use this simplified method after December 31, 2007, for as long as the Company deems it to be the most appropriate method.

Note 3 Discontinued Operations, Business Acquisitions and Dispositions

Discontinued Operations

NRG has classified material business operations, and gains/(losses) recognized on sales, 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.

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 considers cash flow analyses, bids, and offers related to those assets and businesses. In accordance with the provisions of SFAS 144, discontinued operations are not 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.

The following table summarizes NRG s discontinued operations for all periods presented in the Company s consolidated financial statements:

Project	Segment	Initial Discontinued Operations Treatment Date	Disposal Date
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
ITISA	International	Fourth Quarter 2007	First Half 2008[a]

(a) Estimated sale date.

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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, 2007 and 2006.

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Cash and cash equivalents	$ 43	$ 18
Restricted cash	4	3
Receivables, net	4	3
Current assets discontinued operations	51	24
Property, plant and equipment, net	61	54
Other non-current assets	32	28
Non-current assets discontinued operations	93	82
Current portion of long-term debt	10	8
Accounts payable trade	4	3
Other current liabilities	23	17
Current liabilities discontinued operations	37	28
Long-term debt	51	44
Minority interest	1	1
Other non-current liabilities	24	19
Non-current liabilities discontinued operations	$ 76	$ 64

Summarized results of discontinued operations for the years ended December 31, 2007, 2006, and 2005 were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In millions)	
Operating revenues	$ 50	$ 227	$ 323

Operating costs and other expenses		27		224		311
Pre-tax income from operations of discontinued components		23		3		12
Income tax expense		6		1		2
Income from operations of discontinued components		17		2		10
Disposal of discontinued components pre-tax gain				80		13
Income tax expense				4		7
Gain on disposal of discontinued components, net of income taxes				76		6
Income from discontinued operations, net of income taxes	$	17	$	78	$	16

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

There were no pre-tax gains or losses on disposals of the Company s discontinued operations for the year ended December 31, 2007. The pre-tax gain on disposal of the Company s discontinued operations for the years ended December 31, 2006 and 2005 were as follows:

	Year Ended December 31, 2006	Year Ended December 31, 2005 (In millions)	Segment
Resource Recovery	$ 5	$	Corporate
Flinders	60		International
Audrain	15		Corporate
Northbrook New York and Northbrook Energy		12	Corporate
Other		1	Corporate
Total pre-tax gain on disposal of discontinued operations	$ 80	$ 13	

ITISA On December 18, 2007, NRG entered into a sale and purchase agreement to sell 100% interest in Tosli, which holds all NRG s interest in ITISA, to Brookfield Power Inc., a wholly-owned subsidiary of Brookfield Asset Management Inc., for a purchase price of approximately $288 million, plus the assumption of approximately $60 million in debt. The transaction, which is subject to the receipt of regulatory approval and other customary closing conditions, is expected to close during the first half of 2008.

Resource Recovery In 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.

Flinders In 2006, NRG completed 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. 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.

Audrain In 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. 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 In 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.

Acquisition of Texas Genco LLC

On February 2, 2006, NRG acquired Texas Genco LLC, which subsequently is being managed and accounted for as a separate business segment referred to as NRG s Texas region. 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 71 million shares of NRG s common stock valued at approximately $1.7 billion, and acquisition costs of approximately

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$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.

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 approximately 42 million shares of NRG s common stock at a price of $24.38 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.

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 becomes available through December 31, 2008 pursuant to SFAS 141(R).

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 in cash and the assumption of a $1 million liability, with NRG becoming the sole owner of WCP s 1,825 MW of generation capacity in Southern California. In addition, NRG sold to Dynegy the Company s 50%

ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. NRG sold Rocky Road for a fair value sale price of $45 million, paying Dynegy a net purchase price of $160 million at closing. Prior to the purchase, NRG had an existing investment in WCP accounted for as an equity method investment, or Original Investment.

The acquisition of the remaining 50% interest in WCP, or New Investment, was accounted for as a step acquisition since the Original Investment was transacted in a prior period. As a result, the value of the Original Investment and the purchase price of the New Investment were determined and allocated separately. The value of the Original Investment was based on the book value of approximately $159 million as of the date of the acquisition of the New Investment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $48 million. The negative goodwill was subsequently allocated as a reduction to the fair value of WCP s fixed assets. The following table summarizes the purchase price and allocation impact of the WCP acquisition as of March 31, 2006:

			New Investment		
	Original Investment	Fair Value Before Negative Goodwill Allocation	Allocation of Negative Goodwill	Fair Value after Negative Goodwill Allocation	Purchase Price Allocation
			(In millions)		
Current assets	$ 149	$ 153	$	$ 153	$ 302
Property, plant and equipment	24	103	(38)	65	89
Intangible assets	2	26	(10)	16	18
Other non-current assets		9		9	9
Current liabilities	(13)	(18)		(18)	(31)
Non-current liabilities	(3)	(19)		(19)	(22)
Negative goodwill		(48)	48		
Total Equity	$ 159	$ 206	$	$ 206	$ 365

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	2005
	(In millions)	
Operating revenues	$ 5,884	$ 5,891
Net income	399	296
Earnings per share Basic	1.30	0.87

Earnings per share	Diluted	1.27	0.86
Weighted average number of shares outstanding	Basic	267.8	281.6
Weighted average number of shares outstanding	Diluted	288	304

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Note 4 Financial Instruments

The estimated carrying values and fair values of NRG s recorded financial instruments related to continuing operations are as follows:

	Carrying Amount		Fair Value	
	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In millions)			
Cash and cash equivalents	$ 1,132	$ 777	$ 1,132	$ 777
Restricted cash	29	41	29	41
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	32		32	
Marketable equity securities	7		7	
Trust fund investments	390	377	390	377
Notes receivable	126	114	138	126
Long-term debt, including current portion	8,180	8,525	8,164	8,628

For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments. The fair value of marketable securities is based on quoted market prices for those instruments. Trust fund investments are comprised of various U.S. debt and equity securities carried at fair market value.

The fair value of notes receivable, debt securities and certain long-term debt are based on expected future cash flows discounted at market interest rates. The fair value of NRG s traded 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 5 Accounting for Derivative Instruments and Hedging Activities

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 recognized 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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, the majority of trades in support of NRG s baseload units normally qualify for NPNS or cash flow hedge accounting treatment, and 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. 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 purchase 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 or obligation 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, 2007, 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, 2007, 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 2014.

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, 2007, 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 2025.

Coal purchase contracts extending through 2012 designated as normal purchases and disclosed as part of NRG s contractual cash obligations. See Note 21, *Commitments and Contingencies*, for further discussion.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Also, as of December 31, 2007, 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.

Power Tolling contracts through 2017.

Lignite purchase contract through 2018.

Power transmission contracts through 2009.

Natural gas transportation contracts and storage agreements through 2018.

Coal transportation contracts through 2015.

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, 2007, all of NRG s interest rate swap arrangements had been designated as either cash flow or fair value hedges. As of December 31, 2007, NRG had interest rate derivative instruments extending through June 2019.

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.

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The following table summarizes the effects of SFAS 133, on NRG s accumulated other comprehensive income balance attributable to hedged derivatives for the years ended December 31, 2007, 2006 and 2005, net of tax:

	Energy-Related Commodities	Interest Rate	Total
	(In millions)		
Accumulated OCI balance at December 31, 2004	$ 5	$ 2	$ 7
Realized 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)
Realized 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
Realized from OCI during period due to unwinding of previously deferred amounts	(50)	(2)	(52)
Changes in fair value of hedge contracts losses	(377)	(45)	(422)
Accumulated OCI balance at December 31, 2007	$ (234)	$ (31)	$ (265)
Gains expected to unwind from OCI during next 12 months, net of $26 tax	$ 41	$	$ 41

As of December 31, 2007, the net balance in OCI relating to SFAS 133 was an unrecognized loss of approximately $265 million, which is net of $175 million in income taxes. NRG expects $41 million of net deferred gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Statement of Operations

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

The following table summarizes the pre-tax effects of non-hedge derivatives, derivatives that do not qualify as hedges, and ineffectiveness of hedge derivatives on NRG s statement of operations for the years ended December 31, 2007, 2006 and 2005:

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006 (In millions)	For the Year Ended December 31, 2005
Revenue from operations energy commodities	$ (77)	$ 295	$ (154)
Cost of operations			2
Equity in earnings of unconsolidated subsidiaries			12
Interest expense interest rate swaps		(3)	
Total impact to statement of operations	$ (77)	$ 292	$ (140)

For the year ended December 31, 2007, the unrealized loss associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $77 million is comprised of $34 million of fair value increases in forward sales of electricity and fuel, $160 million loss from the reversal of mark-to-market gains,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

which ultimately settled as financial revenues, and $49 million of gains associated with our trading activity. The $34 million of fair value increases in forward sales of electricity and fuel includes approximately $14 million due to the ineffectiveness associated with financial forward contracted electric and gas sales.

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.

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.

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.

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 6 Nuclear Decommissioning Trust Fund

NRG s nuclear decommissioning trust fund assets which are for the decommissioning of South Texas Project, or STP, are primarily comprised of securities recorded at fair value based on actively quoted market prices. NRG accounts for these trust fund assets per SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, because the Company s nuclear decommissioning activities are regulated by the Public Utility Commission of Texas, or PUCT. Although the owners of STP are responsible for the management of decommissioning STP, the cost of decommissioning is the responsibility of the Texas ratepayers. As such, NRG does not bear the cost for these decommissioning responsibilities, except to the extent that NRG has a prudence obligation with respect to the management of the trust funds or the future decommissioning of STP. Third party appraisals are periodically conducted to estimate the future decommissioning liability related to STP. These appraisals are then used to determine the adequacy of the existing decommissioning trust investments to cover that estimated future liability.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Should there be a shortfall in the value of the assets in the trust relative to the estimated liability, NRG has the ability to file a rate case with the PUCT to increase decommissioning reimbursements over time from retail customers. As of December 31, 2007, NRG believes the trust funds are adequately funded.

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

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Cash and cash equivalents	$ 4	$ 7
U.S. government and federal agency obligations	21	29
Federal agency mortgage-backed securities	59	41
Commercial mortgage-backed securities	22	16
Corporate debt securities	44	43
Marketable equity securities	234	216
Total	$ 384	$ 352

Note 7 Inventory

Inventory, which is stated at the lower of weighted average cost or market, consists of:

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Fuel oil	$ 140	$ 162
Coal/Lignite	174	118
Natural gas	16	12
Spare parts	121	128
Total Inventory	$ 451	$ 420

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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, 2007 and 2006 were as follows:

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Capital Lease Receivable non-affiliate		
VEAG Vereinigte Energiewerke AG, due August 31, 2021, 11.00%[(a)]	$ 395	$ 392
Capital Lease non-affiliates	395	392
Less current maturities	30	27
Total	365	365
Note Receivable affiliates		
Kraftwerke Schkopau GBR, indefinite maturity date, 5.89%-7.00%[(b)]	126	114
Notes receivable affiliates	$ 126	$ 114

(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, 2007 and 2006 were as follows:

	As of December 31, 2007	As of December 31, 2006	Depreciable Lives

	(In millions)		
Facilities and equipment	$ 11,829	$ 11,636	5-40 Years
Land and improvements	584	559	
Nuclear fuel	181	159	5 Years
Office furnishings and equipment	84	79	3-10 Years
Construction in progress	337	87	
Total property, plant and equipment	13,015	12,520	
Accumulated depreciation	(1,695)	(974)	
Net property, plant and equipment	$ 11,320	$ 11,546	

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, there was no impairment to goodwill. As of December 31, 2007, NRG had approximately $851 million of goodwill that is deductible for U.S. income tax purposes in future periods.

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 power contracts are amortized based on contracted volumes over the life of each contract and the fuel contracts are amortized over expected 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 2007 and 2006:

As of December 31, 2007	Emission Allowances	Contracts Power	Fuel (In millions)	Water	Other	Total
January 1, 2007	$ 913	$ 92	$ 171	$ 64	$	$ 1,240
Acquisitions	5				2	7
Sales	(1)					(1)
Transfer to held for sale	(1)					(1)
Adjusted gross amount	916	92	171	64	2	1,245
Less accumulated amortization	(114)	(92)	(102)	(64)		(372)
Net carrying amount	$ 802	$	$ 69	$	$ 2	$ 873

As of December 31, 2006	Emission Allowances	Contracts Power	Fuel (In millions)	Water	Total
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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$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.

The following table presents NRG s amortization of intangible assets for the years ended December 31, 2007, 2006 and 2005:

Amortization	**2007**	**2006** (In millions)	**2005**
Emission allowances	$ 40	$ 44	$ 12
Fuel contracts	37	65	
Water contracts	36	28	
Total amortization in cost of operations	$ 113	$ 137	$ 12
Power contract amortization recorded as a reduction to operating revenues	$	$ 43	$ 12

The following table presents estimated amortization related to NRG s emission allowances and in-market contracts:

Year Ended December 31,	**Emission Allowances**	**Fuel** (In millions)	**Total**
2008	$ 41	$ 21	$ 62
2009	41	26	67
2010	55	6	61
2011	54	2	56
2012	45	2	47

The weighted average remaining amortization period is 3.3 years for fuel 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, 2007, the value of emission allowances held-for-sale is $14 million and is managed within 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 operations.

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
2008	$ 33	$ 11	$ 279	$ 323
2009	19	34	82	135
2010	6	28	32	66
2011			22	22
2012			22	22

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Note 11 Debt and Capital Leases

Long-term debt and capital leases consist of the following:

As of December 31,	2007	2006	Interest Rate
	(In millions except rates)		
NRG Recourse Debt:			
Senior notes due 2017	$ 1,100	$ 1,100	7.375
Senior notes due 2016	2,400	2,400	7.375
Senior notes due 2014[(a)]	1,199	1,183	7.25
ML note payable		11	L+1.9[(e)]
Term loan B due 2013	2,816	3,148	L+1.75/L+2.0[(e)]
NRG Non-Recourse Debt:			
CSF non-recourse obligations due 2008 and 2009	333	333	5.45-13.23
NRG Peaker Finance Co. LLC, due June 2019[(b)]	235	240	L+1.07[(e)]
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013 and 2017[(c)]	97	107	7.12-7.31
Camas Power Boiler LP, unsecured term loan, due June 2007		1	L+0.69[(e)]
Camas Power Boiler LP, revenue bonds, due August 2007		2	3.38
Subtotal long term debt	8,180	8,525	
Capital leases:			
Saale Energie GmbH, Schkopau capital lease, due 2021	181	199	
Other		2	
Subtotal	8,361	8,726	
Less current maturities[(d)]	466	123	
Total	$ 7,895	$ 8,603	

(a) Includes fair value adjustment as of December 31 2007 and 2006, reflects $(1) million and $(17) million, respectively, 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 $(43) million and $(50) million as of December 31, 2007 and 2006, respectively.

(c) Includes premium of $3 million and $4 million as of December 31, 2007 and 2006, respectively.

(d) Includes premium of $7 million on the NRG Peaker Finance debt and a discount of $1 million on NRG Energy Center Minneapolis debt as of December 31, 2007 and 2006.

(e) L+ equals LIBOR plus x%

NRG Recourse Debt

Senior Notes

NRG has three outstanding issuances of senior notes, or Senior Notes, under an Indenture, dated February 2, 2006, or the Indenture, between NRG and Law Debenture Trust Company of New York, as trustee:

(i) 7.25% senior notes, issued February 2, 2006 and due February 1, 2014, or the 2014 Senior Notes;

(ii) 7.375% senior notes issued February 2, 2006 and due February 1, 2016, or the 2016 Senior Notes;

(iii) 7.375% Senior Notes issued November 21, 2006 and due January 15, 2017, or the 2017 Senior Notes.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental indentures to the series of notes have been issued to add newly formed or acquired subsidiaries as guarantors.

The Indentures and the form of notes provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG. The Indentures also 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 capital to shareholders;
- grant liens on assets to lenders; and
- incur additional debt.

Interest is payable semi-annually on the Senior Notes until their maturity dates.

At any time prior to February 1, 2009, NRG may redeem up to 35% of the aggregate principal amount of the 2014 Senior Notes and the 2016 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 2014 Senior Notes, and 107.375% of the principal amount, in the case of the 2016 Senior Notes. In addition, NRG may redeem the 2014 Senior Notes and 2016 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 2014 Senior Notes, or the First Applicable 7.25% Redemption Date, NRG may redeem all or a portion of the 2014 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 2014 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 2016 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

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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 2016 Senior Notes:

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%

Prior to January 15, 2012, NRG may redeem up to 35% of the 2017 Senior Notes 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 remain 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 2017 Senior Notes:

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%

In November 2007, NRG made a repayment of $11 million on a revolving note after Merrill Lynch put the note back to the Company.

Senior Credit Facility

2007 Activity On June 8, 2007, NRG completed a $4.4 billion refinancing of the Company s then existing senior credit facility which was comprised of a 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 senior first priority secured synthetic letter of credit facility, or the Letter of Credit Facility. The refinancing resulted in a 0.25% reduction on the spread that the Company pays on its Term B loan and Synthetic Letter of Credit Facility, a $200 million reduction in the Synthetic Letter of Credit Facility from $1.5 billion to $1.3 billion, and various amendments to provide improved flexibility, efficiency for returning capital to shareholders, asset repowering and investment opportunities. The pricing on the Company s Term B loan and Synthetic Letter of Credit Facility is also subject to further reductions upon the achievement of certain financial ratios. The refinancing resulted in a charge of approximately $35 million to the Company s results of operations for the year ended December 31, 2007, which was primarily related to the write-off of previously deferred financing costs.

On August 6, 2007, NRG entered into an agreement with BNP Paribas, or BNP, whereby BNP has agreed to be an issuing bank under the revolver portion of the Company s Senior Credit Facility. BNP has agreed to issue up to $350 million of letters of credit under the revolver. This increased the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility to $650 million. As of December 31, 2007, NRG was permitted to issue additional letters of credit of up to $350 million under the Senior Credit Facility through other financial institutions.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 31, 2007, the Company used cash on hand to prepay, without penalty, $300 million of its Term B loan under the Senior Credit Facility. With this prepayment, the Company has met a financial ratio by the end of 2007 that would result in a 0.25% reduction in the interest rate on both its Term B loan and Synthetic Letter of Credit Facility. The prepayment will be credited against the Company s mandatory annual prepayment which is required in March 2008 under the Senior Credit Facility.

Significant terms The Term Loan Facility matures on February 1, 2013, and amortizes in 27 consecutive equal quarterly installments of 0.25% term loan commitments, beginning June 30, 2006, with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011. The Synthetic Letter of Credit Facility will mature on February 1, 2013, and no amortization will be required in respect thereof. As of December 31, 2007, NRG had issued $743 million under the Company s Synthetic Letter of Credit Facility and $3 million in letters of credit under the Company s Revolving Credit Facility. NRG has the option to prepay the Senior Credit Facility in whole or in part at any time.

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. Based on current credit market conditions the Company expects that its lenders will accept in full the mandatory offer required in March 2008, and, as such, the Company has reclassified approximately $146 million of Term Loan B maturity from a non-current to a current liability as of December 31, 2007.

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.

Interest Rate Swaps In connection with the Senior Credit Facility, NRG entered into a series of forward-setting interest rate swaps in 2006 which 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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The notional amounts and maturities of each tranche of these swaps as of December 31, 2007 are as follows:

Maturity	Notional Value
March 31, 2008	$ 140 million
March 31, 2009	$ 150 million
March 31, 2010	$ 190 million
March 31, 2011	$ 1.55 billion

Holdco Credit Facility

During 2007, the Company initiated a capital allocation strategy that contemplated NRG becoming a wholly-owned operating subsidiary of a newly created holding company, NRG Holdings, Inc. or Holdco, with the stockholders of NRG becoming stockholders of Holdco. On June 8, 2007, NRG executed a Holdco Credit Facility, a delayed-draw credit facility that expired December 28, 2007 that provided for the funding of $1 billion in term loan financing to Holdco which was intended for Holdco to make a capital contribution to NRG in the amount of $1 billion, to be used to prepay a portion of NRG s existing Term B loan. As part of the commitment NRG agreed to pay a fee equal to 0.5% of the facility for the first 180 days and 0.75% thereafter.

In November 2007, NRG exercised its right to provide its Senior Note holders with a conditional change of control notice, and related offer to purchase the Company s Senior Notes at 101% of par, prior to the actual formation of the Holdco structure. Concurrently, NRG also sought consent from its Senior Note holders to either waive the change of control or permit additional restricted payments under the indentures. In December 2007, the conditional tender offers and concurrent consent solicitations expired with no tendered Senior Notes accepted for payment and without receipt of the requisite consents to amend the indentures for the Senior Notes. Consequently, the Company decided not to move forward and form the Holdco structure.

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 was to repurchase $500 million shares of NRG s common stock in the public markets or in privately negotiated transactions in connection with the Company s Capital Allocation Program. 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 or the Company s other subsidiaries.

These notes and preferred interests contain a feature considered an embedded derivative, which requires NRG to pay to Credit Suisse at maturity, either in cash or stock, the excess of NRG s then current stock price over a Reference

Price. This Reference Price is the price of NRG s stock in excess of a compound annual growth rate, or CAGR, of 20% beyond the volume-weighted average share price of the stock at the time of repurchase. Although this feature is considered a derivative, it is exempt from derivative accounting under the guidance in paragraph 11(a) of SFAS 133, and will only be recognized upon settlement with a corresponding impact to Additional Paid-In Capital if settled in stock.

Notes As of December 31, 2007, CSF I and CSF II issued a total of $249 million in notes in connection with Phase I of the Capital Allocation Program that 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%.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Preferred Interests As of December 31, 2007, 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%.

CSF I Extension On February 27, 2008, the Company entered into an arrangement with Credit Suisse that allows the Company, at the Company s option and subject to customary closing conditions, to extend the $220 million notes and preferred interest maturities of CSF I from October 2008 to June 2010. In addition, the previous settlement date for any share price appreciation beyond a 20% compound annual growth rate since the original date of purchase by CSF I, may be extended 30 days to early December 2008. As part of this extension arrangement, the Company intends to contribute to CSF I additional collateral in the form of treasury shares to maintain a blended interest rate of CSF I facility of approximately 7.5%. The Company expects to implement this extension arrangement by March 17, 2008.

Project Financings

The following are descriptions of certain indebtedness of NRG s project subsidiaries that remain outstanding as of December 31, 2007. 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, 2007, approximately $279 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 $36 million remained outstanding as of December 31, 2007. In July 2002, NRG Thermal Minneapolis issued an additional $55 million of 7.25% Series A notes due August 2017, of which approximately $42 million remained outstanding as of December 31, 2007, and $20 million of 7.12% Series B notes due August 2017, of which approximately $15 million remained outstanding as of December 31, 2007. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt Related to Discontinued Operations

As discussed in Note 3, *Discontinued Operations, Business Acquisitions and Dispositions*, on December 18, 2007, NRG entered into a sale and purchase agreement to sell its interest in ITISA, and consequently all ITISA debt, approximately $60 million at December 31, 2007, has been classified as discontinued operations.

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 $1.1 billion). As of December 31, 2007, approximately 239 million (approximately $349 million) remained outstanding at Schkopau. Interests on the individual loans accrue at fixed rates averaging 5.47% per annum, with maturities occurring between 2008 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, 2007, the capital lease obligation at SEG was approximately $181 million.

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, 2007 are as follows:

	(In millions)
2008	$ 472
2009	226
2010	75
2011	70
2012	71
Thereafter	7,488
Total	$ 8,402

NRG s future minimum lease payments for capital leases included above as of December 31, 2007 are as follows:

		(In millions)
2008	$	93
2009		42
2010		24
2011		15
2012		13
Thereafter		203
Total minimum obligations		390
Interest		209
Present value of minimum obligations		181
Current portion		75
Long-term obligations	$	106

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12 Benefit Plans and Other Postretirement Benefits

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.

NRG sponsors and operates three defined benefit pension and other postretirement plans. The NRG Plan for Bargained Employees and the NRG Plan for Non-bargained Employees are maintained solely for eligible legacy NRG participants. A third plan, the Texas Genco Retirement Plan, is maintained for participation solely by eligible Texas based employees. NRG expects to contribute approximately $87 million to the Company s three pension plans in 2008.

NRG Plans for Bargained and Non-bargained Employees Substantially all employees hired prior to December 5, 2003 were eligible to participate in NRG s legacy 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.

Texas Genco Retirement Plan The Texas region s pension plan is a noncontributory defined benefit pension plan that provides a final average pay benefit or cash balance benefit, where the participant receives the more favorable of the two formulas, based on all years of service. 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 on 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.

NRG Defined Benefit Plans

The net annual periodic pension cost related to NRG domestic pension and other postretirement benefit plans include the following components:

	Pension Benefits		
	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In millions)	

Service cost benefits earned	$	15	$	17	$	11
Interest cost on benefit obligation		17		15		4
Expected return on plan assets		(11)		(7)		
Net periodic benefit cost	$	21	$	25	$	15

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Other Postretirement Benefits		
	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In millions)		
Service cost benefits earned	$ 2	$ 3	$ 2
Interest cost on benefit obligation	5	4	3
Net periodic benefit cost	$ 7	$ 7	$ 5

A comparison of the pension benefit obligation, other post retirement benefit obligations, and related plan assets as of December 31, 2007 and 2006 for NRG s plans on a combined basis is as follows:

	Pension Benefits		Other Postretirement Benefits	
	As of December 31, 2007	As of December 31, 2006	As of December 31, 2007	As of December 31, 2006
	(In millions)			
Benefit obligation at January 1	$ 294	$ 318	$ 80	$ 80
Service cost	15	17	2	3
Interest cost	17	15	5	4
Plan amendments	(4)			
Actuarial (gain)/loss	(13)	(29)	(2)	(6)
Benefit payments	(19)	(27)	(2)	(1)
Benefit obligation at December 31	$ 290	$ 294	$ 83	$ 80
Fair value of plan assets at January 1	123	86		
Actual return on plan assets	7	14		
Employer contributions	58	51	1	1
Benefit payments	(20)	(28)	(1)	(1)
Fair value of plan assets at December 31	$ 168	$ 123	$	$
Funded status at December 31 excess of obligation over assets	$ (122)	$ (171)	$ (83)	$ (80)

Amounts recognized in NRG s balance sheets were as follows:

	Pension Benefits		Other Postretirement Benefits	
	As of December 31, 2007	As of December 31, 2006	As of December 31, 2007	As of December 31, 2006
	(In millions)			
Assets	$	$	$	$
Current liabilities				
Non-current liabilities	122 166	171	83	80

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amounts recognized in NRG s accumulated other comprehensive income that have not yet been recognized as components of net periodic benefit cost were as follows:

	Pension Benefits		Other Postretirement Benefits	
	As of December 31, 2007	As of December 31, 2006	As of December 31, 2007	As of December 31, 2006
	(In millions)			
Unrecognized (gain)/loss	$ (36)	$ (27)	$ 1	$ 1
Prior service credit	$ (3)	$	$	$

Other changes in plan assets and benefit obligations recognized in other comprehensive income were as follows:

As of December 31,	Pension Benefits	Other Postretirement Benefits
	2007	
	(In millions)	
Net gain	$ (8)	$ (2)
Prior service credit	$ (4)	$
Total recognized in other comprehensive income	$ (12)	$ (2)
Total recognized in net periodic pension cost and other comprehensive income	$ 9	$ 5

The Company s estimated net gain for NRG s domestic pension plan that will be amortized from the accumulated other comprehensive income to net periodic cost over the next fiscal year is $1 million.

The following table presents the balances of significant components of NRG s domestic pension plan:

	Pension Benefits	
	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Projected benefit obligation	$ 290	$ 294
Accumulated benefit obligation	236	226

Fair value of plan assets	168	123

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	**2007**	**2006**	**2007**	**2006**
Discount rate	6.56%	5.92%	6.56%	5.92%
Rate of compensation increase	4.00-4.50%	4.00-4.50%		
Health care trend rate			9.5% grading to 5.5% in 2016	10.5% grading to 5.5% in 2012

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the significant assumptions used to calculate NRG s benefit expense:

	As of December 31,					
	Pension Benefits			Other Postretirement Benefits		
ted-Average Assumptions	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
nt rate	5.92%	5.50%	5.75%	5.92%	5.50%	5
ed return on plan assets	8.00%	8.00%	8.00%			
compensation increase	4.00-4.50%	4.00-4.50%	4.00-4.50%			
care trend rate				10.5% grading to 5.5% in 2012	11.5% grading to 5.5% in 2012	9% gr to 5.5% ir

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, 2007 and 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 were based on investment yields available on AA rated long-term corporate bonds.

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, 2007 and 2006 were as follows:

	As of December 31, 2007	As of December 31, 2006
US Equity	50-55%	55%
International Equity	15%	17%
US Fixed Income	30-35%	28%

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NRG s expected future benefit payments for each of the next five years, and in the aggregate for the five years thereafter, are as follows:

	Pension Benefit Payments	Other Postretirement Benefit: Benefit Payments	Other Postretirement Benefit: Medicare Prescription Drug Reimbursements
		(In millions)	
2008	$ 13	$ 2	$
2009	14	2	
2010	16	3	
2011	17	3	
2012	19	4	
2013-2017	$ 126	$ 25	$ 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	(5)

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in STP, as discussed further in Note 26, *Jointly Owned Plants*. STPNOC, who operates and maintains STP, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. For the period ending December 31, 2007 and 2006, NRG reimbursed STPNOC approximately $12 million and $4 million, respectively, towards its defined benefit plans. In 2008, NRG expects to reimburse STPNOC approximately $6 million for its contributions towards the plans.

The Company has recognized the following in its statement of financial position and accumulated other comprehensive income related to its 44% interest in STP:

	Pension Benefits		Other Postretirement Benefits	
	As of	As of	As of	As of

	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
	(In millions)			
Funded status STPNOC benefit plans	$ (20)	$ (27)	$ (22)	$ (16)
Net periodic pension costs	4	5	3	3
Other changes in plan assets and benefit obligations recognized in other comprehensive income	$ 4	$ 1	$ 4	$

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 $16 million, $15 million, and $5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13 Capital Structure

Stock Split

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

The following table reflects the changes in NRG s common stock issued and outstanding for the year ended December 31, 2007 and 2006:

	Authorized	Issued	Treasury	Outstanding
Balance as of December 31, 2005	500,000,000	200,097,352	(38,693,576)	161,403,776
Shares issued January 2006		41,710,114		41,710,114
Acquisition of Texas Genco LLC		32,119,008	38,693,576	70,812,584
Capital Allocation Program Phase I and II during 2006			(29,601,162)	(29,601,162)
Shares issued from LTIP through December 31, 2006		321,790		321,790
Balance as of December 31, 2006	500,000,000	274,248,264	(29,601,162)	244,647,102
Capital Allocation Program Phase II during 2007			(7,006,700)	(7,006,700)
Additional Share Repurchases December 2007			(2,037,700)	(2,037,700)
Shares issued from LTIP through December 31, 2007		1,132,227		1,132,227
Retirement of shares through December 31, 2007		(14,094,962)	14,094,962	
Balance as of December 31, 2007	500,000,000	261,285,529	(24,550,600)	236,734,929

Common Stock

NRG s authorized common stock consists of 500 million shares of NRG stock. Common stock issued as of December 31, 2007 and 2006 was 261,285,529 and 274,248,264 shares, respectively, at a par value of $0.01 per share. Common stock issued and outstanding as of December 31, 2007 and 2006 were 236,734,929 and 244,647,102, respectively.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes NRG s common stock reserved for the maximum number of shares potentially issuable based on the conversion and redemption features of outstanding equity instruments and the long term incentive plan as of December 31, 2007:

Equity Instrument	Common Stock Reserve Balance
4% Convertible perpetual preferred	26,151,972
3.625% Redeemable perpetual preferred	16,000,000
5.75% Mandatory convertible preferred	20,520,000
Long term incentive plan	14,565,741
Total	77,237,713

Treasury Stock

As of December 31, 2007 and 2006, NRG had repurchased 24,550,600 shares and 29,601,162 shares, respectively at a cost of approximately $638 million and $732 million, respectively, of the Company s common stock.

In 2006, NRG initiated a Capital Allocation Program to be executed in two phases. Phase I, completed in the fourth quarter 2006, resulted in the repurchase of 21,175,400 shares of the Company s common stock for approximately $500 million. Phase II, also a $500 million share buyback program, began in the fourth quarter 2006 with the repurchase of 8,425,762 shares of NRG common stock for approximately $232 million. NRG completed Phase II in the third quarter 2007. The Company has thus repurchased 7,006,700 shares of NRG common stock for approximately $268 million relating to Phase II of the Capital Allocation Program for the year ended December 31, 2007.

In December 2007, the Company repurchased 2,037,700 shares of NRG common stock for approximately $85 million. In January 2008, the Company repurchased an additional 344,000 shares of NRG common stock for approximately $15 million.

Retirement of Treasury Stock

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

Preferred Stock

As of December 31, 2007, the Company had 10,000,000 shares of preferred stock authorized. As of December 31, 2007, 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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Included in the agreement is a call option which allows that at any time prior to March 16, 2009, should the price of NRG s common stock exceed $45.375, for at least 20 trading days within a period of 30 consecutive trading days, NRG may elect to cause the conversion of all, but not less than all, of its 5.75% Preferred Stock outstanding at the minimum conversion rate of 8.2712 shares of the Company s common stock for each share of the 5.75% Preferred Stock. However, NRG can cause conversion only if it pays the holders in cash an amount equal to any accrued, accumulated and unpaid dividends on the outstanding 5.75% Preferred Stock declared and not declared plus the present value of all remaining future dividends through March 16, 2009.

Also included is an early conversion feature by the holders which is contingent upon a cash acquisition of NRG on or prior to March 16, 2009. This feature requires paying converting holders an amount equal to the sum of any accumulated and unpaid dividends, the present value of all remaining dividend payments through and including March 16, 2009, and a specified conversion rate determined by reference to the price per share of the Company s common stock paid in such acquisition for each share of the outstanding 5.75% Preferred Stock. However, should such a transaction be consummated by a public acquirer, in lieu of providing for conversion and paying the dividend amount, the Company may adjust its conversion obligation such that upon conversion of the outstanding 5.75% Preferred Stock, NRG will deliver the acquirer 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 $30.23	8.2712
less than $30.23 but greater than $24.38	8.2712 to 10.2564
less than or equal to $24.38	10.2564

4% Preferred Stock

As of December 31, 2007 and 2006, 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 $20.00 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 ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, 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, 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 $29.54 and (ii) zero, times (b) 50.77. The number of NRG common stock to be delivered under the conversion feature is limited to 16,000,000 shares. If upon conversion, the Market Price is less than $19.69, 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) $19.69 minus the Market Price, times (ii) 50.77. 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, 2007:

	Economic

Name	Geographic Area	Interest
MIBRAG	Germany	50.0%
Saguaro Power Company, or Saguaro	USA	50.0%
Gladstone Power Station, or Gladstone	Australia	37.5%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method for the years ended December 31, 2007, 2006 and 2005 was as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In millions)	
Summarized Statements of Operations			
Operating revenues	$ 871	$ 910	$ 1,300
Costs and expenses	748	770	1,107
Net income	123	140	193
Summarized Balance Sheets			
Current assets	268	223	
Non-current assets	1,808	1,697	
Total assets	2,076	1,920	
Current liabilities	88	53	
Non-current liabilities	950	1,021	
Equity	1,038	846	
Total liabilities and equity	2,076	1,920	
NRG s share of equity and net income			
NRG s share of equity	425	344	
NRG s share of net income	$ 54	$ 60	$ 104

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. For the years ended December 31, 2007, 2006 and 2005, NRG s equity earnings from MIBRAG were approximately $36 million, $30 million and $26 million, respectively.

As discussed in Note 2, *Summary of Significant Accounting Policies*, the Company s MIBRAG equity investment was negatively affected by the adoption of EITF 04-6. Upon adoption of EITF 04-6 on January 1, 2006, NRG s investment in MIBRAG was reduced by approximately $93 million, with an offsetting charge to retained earnings.

Saguaro Power Company NRG owns a 50% interest in the Saguaro plant, a cogeneration plant with dual-fuel capability, natural gas and oil. For the year ended December 31, 2007, NRG s equity loss from Saguaro was $3 million and a loss of approximately $1 million for the year ended December 31, 2006. NRG had no equity earnings in 2005 from Saguaro. However, 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.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, 2006 and 2005, NRG s equity earnings from Gladstone were approximately $21 million, $25 million and $24 million, respectively.

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, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Segment
		(In millions)		
Powersmith Cogeneration	$ 1	$	$	Corporate
Latin American Funds		3		International
James River Power LLC		(6)		Corporate
Cadillac		11		Corporate
Saguaro			(27)	West
Rocky Road			(20)	Corporate
Kendall			4	Corporate
Enfield			12	International
Total write downs and gains/(losses) on sales of equity method investments	$ 1	$ 8	$ (31)	

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.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 and preferred interests and notes issued by CSF I and CSF II include conversion features that, if dilutive, are calculated using the if-converted method as well.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The reconciliation of NRG s basic earnings per common share to diluted earnings per share for the years ended December 31, 2007, 2006 and 2005 is shown in the following table:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In millions)	
Basic earnings per share			
Numerator:			
Income from continuing operations	$ 569	$ 543	$ 68
Deduct preferred stock dividends	(55)	(52)	(20)
Income available to common stockholders from continuing operations	514	491	48
Discontinued operations, net of tax	17	78	16
Net income available to common stockholders	$ 531	$ 569	$ 64
Denominator:			
Weighted average number of common shares outstanding	240.2	258.0	169.2
Basic earnings per share:			
Income from continuing operations	$ 2.14	$ 1.90	$ 0.28
Discontinued operations, net of tax	0.07	0.31	0.10
Net income	$ 2.21	$ 2.21	$ 0.38
Diluted earnings per share			
Numerator:			
Income available to common stockholders from continuing operations	514	491	48
Add preferred stock dividends for dilutive preferred stock	46	43	
Adjusted income from continuing operations	560	534	48
Discontinued operations, net of tax	17	78	16
Net income available to common stockholders	$ 577	$ 612	$ 64
Denominator:			
Weighted average number of common shares outstanding	240.2	258.0	169.2
Incremental shares attributable to the issuance of stock-based compensation (treasury stock method)	3.8	2.8	1.4
Incremental shares attributable to embedded derivatives of certain financial instruments (if-converted method)	6.0		

Incremental shares attributable to the assumed conversion features of outstanding preferred stock (if-converted method)		37.5		39.8		
Total dilutive shares		287.5		300.6		170.6
Diluted earnings per share:						
Income from continuing operations	$	1.95	$	1.78	$	0.28
Discontinued operations, net of tax		0.06		0.26		0.10
Net income	$	2.01	$	2.04	$	0.38

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In millions of shares)		
Equity compensation NQSO s and PU s	0.1	0.7	0.4
Convertible preferred stock			21.0
Embedded derivative of 3.625% redeemable perpetual preferred stock	12.2	16.0	16.0
Embedded derivative of preferred interests and notes issued by CSF I and CSF II	16.1	18.3	
Total	28.4	35.0	37.4

Note 17 Segment Reporting

NRG s segment structure reflects 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.

The following table summarizes customers from whom NRG derived more than 10% of the Company s consolidated revenues for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
Customer A Northeast region	%	10%	40%
Customer B Northeast region			17
Customer C Texas region	27		
Total	27%	10%	57%

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2007								
	Wholesale Power Generation								
	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
	(In millions)								
Operating revenues	$ 3,287	$ 1,605	$ 658	$ 127	$ 140	$ 159	$ 30	$ (17)	$ 5,989
Operating expenses	1,849	1,045	533	85	112	125	47	(8)	3,788
Depreciation and amortization	469	102	68	3		11	5		658
Gain/(loss) on sale of assets						18	(1)		17
Operating income/(loss)	969	458	57	39	28	41	(23)	(9)	1,560
Equity in earnings/(loss) of unconsolidated affiliates				(3)	57				54
Write downs and gain on sales of equity method investments							1		1
Other income, net	7				8	1	58	(19)	55
Refinancing expenses							(35)		(35)
Interest expense	(164)	(57)	(53)		(5)	(6)	(423)	19	(689)
Income/(loss) from continuing operations before income taxes	812	401	4	36	88	36	(422)	(9)	946
Income tax expense/(benefit)	327				(12)		62		377
Income/(loss) from continuing operations	485	401	4	36	100	36	(484)	(9)	569
Income on discontinued operations, net of income taxes					17				17
Net income/(loss)	$ 485	$ 401	$ 4	$ 36	$ 117	$ 36	$ (484)	$ (9)	$ 586
Balance sheet									
Equity investments in affiliates		1		27	397				425
Capital expenditures	190	106	30	80		6	69		481
Goodwill	1,781						5		1,786
Total assets	$ 12,165	$ 1,572	$ 995	$ 246	$ 1,169	$ 211	$ 12,847	$ (9,931)	$ 19,274

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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	$ 135	$ 152	$ 12	$ (61)	$ 5,585
Operating expenses	1,794	993	397	135	110	121	30	(3)	3,577
Depreciation and amortization	413	89	68	3		12	5		590
Operating income/(loss)	881	461	105	8	25	19	(23)	(58)	1,418
Equity in earnings of unconsolidated affiliates				1	57		2		60
Write downs and gain on sales of equity method investments					3		5		8
Other income, net	9	6		1	7	1	152	(20)	156
Refinancing expenses							(187)		(187)
Interest expense	(138)	(63)	(57)		(1)	(7)	(344)	20	(590)
Income/(loss) from continuing operations before income taxes	752	404	48	10	91	13	(395)	(58)	865
Income tax expense/(benefit)	23			(2)	23		278		322
Income/(loss) from continuing operations	729	404	48	12	68	13	(673)	(58)	543
Income on discontinued operations, net of income taxes					61		17		78
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	$ 12,608	$ (10,484)	$ 19,436

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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	$ 135	$ 150	$ 6	$ (9)	$ 2,400
Operating expenses	1,262	485	9	107	118	35	(11)	2,005
Depreciation and amortization	74	67	1		11	5		158
Corporate relocation charges						6		6
Restructuring and impairment charges						6		6
Operating income/(loss)	218	8	(6)	28	21	(46)	2	225
Equity in earnings of unconsolidated affiliates			22	69		13		104
Write downs and gain/(loss) on sales of equity method investments			(27)	12		(16)		(31)
Other income, net	4		1	17	2	51	(21)	54
Refinancing expenses						(65)		(65)
Interest expense		(27)		(1)	(8)	(162)	21	(177)
Income/(loss) from continuing operations before income taxes	222	(19)	(10)	125	15	(225)	2	110
Income tax expense				21	4	17		42
Income/(loss) from continuing operations	222	(19)	(10)	104	11	(242)	2	68
Income on discontinued operations, net of income taxes				2	4	10		16
Net income/(loss)	$ 222	$ (19)	$ (10)	$ 106	$ 15	$ (232)	$ 2	$ 84

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 18 Income Taxes

The income tax provision from continuing operations for the years ended December 31, 2007, 2006 and 2005 consisted of the following amounts:

	Year Ended December 31, 2007	Year Ended December 31, 2006 (In millions)	Year Ended December 31, 2005
Current			
U.S	$ (7)	$ (27)	$ 19
Foreign	20	19	15
	13	(8)	34
Deferred			
U.S	394	326	2
Foreign	(30)	4	6
	364	330	8
Total income tax	$ 377	$ 322	$ 42
Effective tax rate	39.9%	37.2%	38.2%

The following represents the domestic and foreign components of income from continuing operations before income tax expense for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31, 2007	Year Ended December 31, 2006 (In millions)	Year Ended December 31, 2005
U.S.	$ 860	$ 767	$ (11)
Foreign	86	98	121
Total	$ 946	$ 865	$ 110

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, 2006 and 2005 were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In millions, except percentages)		
Income from continuing operations before income taxes	$ 946	$ 865	$ 110
Tax at 35%	331	303	39
State taxes, net of federal benefit	46	34	(1)
Foreign operations	(13)	(21)	(18)
2005 Section 965 taxable dividend			5
Subpart F taxable income		11	19
Valuation allowance, including change in state effective rate	6	(10)	22
Change in state effective tax rate		21	(22)
Claimant reserve settlements		(28)	
Change in local German effective tax rates	(29)		
Foreign dividends	26	1	
Non-deductible interest	10	3	
Permanent differences, reserves, other		8	(2)
Income tax expense	$ 377	$ 322	$ 42
Effective income tax rate	39.9%	37.2%	38.2%

The effective income tax rate for the year ended December 31, 2007 differs from the U.S. statutory rate of 35% primarily due to a taxable dividend from foreign operations and non-deductible interest, offset by earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate including the impact of a law change that reduced the German tax rate.

For the year ended December 31, 2007, NRG s state effective income tax rate has remained at 7%, which is consistent with its 2006 rate. For the year ended December 31, 2006, the Company 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 was 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 during 2006. 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.

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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, 2007 and 2006, consisted of the following:

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Deferred tax liabilities:		
Discount/premium on notes	$ 23	$ 25
Emissions allowances	109	83
Difference between book and tax basis of property	1,568	1,579
Derivative asset, net		216
Goodwill	45	51
Investment in projects	6	
Total deferred tax liabilities	1,751	1,954
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	129	133
Derivative liability, net	125	
Differences between book and tax basis of contracts	577	890
Non-depreciable property	19	21
Intangibles amortization (excluding goodwill)	152	145
Equity compensation	15	16
Claimants reserve	7	8
U.S. net operating loss carry forwards		27
U.S. capital loss carryforwards	439	485
Foreign net operating loss carryforwards	80	74
Foreign capital loss carryforwards	1	
Investments in projects		6
Deferred financing costs	12	
Other	15	12
Total deferred tax assets	1,571	1,817
Valuation allowance	(539)	(581)
Net deferred tax assets	1,032	1,236
Net deferred tax liability	$ 719	$ 718

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes NRG s net deferred tax position as of December 31, 2007 and 2006:

	As of December 31, 2007	As of December 31, 2006
	(In millions)	
Current deferred tax asset	$ 124	$
Current deferred tax liability		164
Non-current deferred tax liability	843	554
Net deferred tax liability	$ 719	$ 718

The effective income tax rate for the year ended December 31, 2007 differs from the U.S. statutory rate of 35% due to a taxable dividend from foreign operations and non-deductible interest, offset by earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate including the impact of a law change that reduced the German tax rate. For the year ended December 31, 2006, the effective tax rate differs from the U.S. statutory rate of 35% due to settlements paid from a claimant reserve established at bankruptcy as well as earnings in foreign jurisdictions that are taxed at rates lower than the U.S. statutory rate.

Deferred tax assets and valuation allowance

Net deferred tax balance As of December 31, 2007, NRG recorded a net deferred tax liability of $180 million. Due to an assessment of positive and negative evidence, related to projected capital gains and available tax planning strategies, NRG believes that it is more likely than not that a benefit will not be realized on $539 million of tax assets, thus a valuation allowance has remained, resulting in a net deferred tax liability of $719 million. NRG believes it is more likely than not that future earnings will be sufficient to utilize the Company s deferred tax assets, net of the existing valuation allowances at December 31, 2007.

NOL carryforwards As of December 31, 2007, the Company had generated total domestic pretax book income of $860 million which fully utilized cumulative domestic net operating loss, or NOL, in the amount of $245 million. In addition, as of December 31, 2007, NRG has cumulative foreign NOL carryforwards of $288 million of which $72 million will expire starting 2011 through 2016 and of which $216 million do not have an expiration date.

Valuation allowance As of December 31, 2007, the Company s valuation allowance and other deferred tax items were reduced as a result of the reduction in NRG s net deferred tax assets. In accordance with SOP 90-7, these movements resulted in an increase in Additional Paid in Capital of approximately $56 million.

As of December 31, 2006, 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 approximately $22 million (of which $3 million was reflected in discontinued operations).

Any future reductions to valuation allowance will be recorded to Additional Paid-in-Capital with the exception of $14 million which will be recorded to income tax expense.

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. If NRG does not permanently reinvest earnings then deferred taxes of approximately $39 million would be recognized for the cumulative translation adjustment as of December 31, 2007.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $5 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, recognized within discontinued operations, of approximately $5 and $3 million in 2007 and 2006 respectively. This tax holiday will expire in December 31, 2013.

Uncertain tax benefits

NRG has identified certain unrecognized tax benefits whose after-tax value was $683 million, of which $19 million would impact the Company s effective tax rate if recognized. Of the $683 million in unrecognized tax benefits, $664 million relates to periods prior to the Company s emergence from bankruptcy. In accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*, and the application of fresh start accounting, recognition of previously unrecognized tax benefits existing pre-emergence would not impact the Company s effective tax rate but would increase Additional Paid in Capital. As of December 31, 2007, NRG has recorded a $7 million non-current tax liability for unrecognized tax benefits. This amount was recorded after utilization in 2007 of the cumulative domestic NOL. In accordance with SFAS 141(R), any changes to our uncertain tax benefits occurring after 1/1/2009, will be credited to income tax expense rather than APIC.

NRG has accrued interest and penalties related to these unrecognized tax benefits of approximately $4 million as of the adoption of FIN 48 by the Company on January 1, 2007. The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. For the year ended December 31, 2007, the Company incurred an immaterial amount of interest and penalties related to its unrecognized tax benefits.

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

Sale of ITISA On December 18, 2007, NRG entered into a sale and purchase agreement to sell 100% interest in Tosli, which holds all NRG s interest in ITISA, to Brookfield Power Inc., a wholly-owned subsidiary of Brookfield Asset Management Inc., for a purchase price of approximately $288 million, plus the assumption of approximately $60 million in debt. The transaction, which is subject to the receipt of regulatory approval and other customary closing conditions, is expected to close during the first half of 2008. We expect a portion of this sale to result in capital gain, which will further reduce our uncertain tax benefits.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	As of December 31, 2007 (In millions)
Balance as of January 1	$ 712
Increase due to current year positions	76
Decrease due to current year positions	(105)
Increase due to prior year positions	
Decrease due to prior year positions	
Decrease due to settlements and payments	
Decrease due to statute expirations	
Unrecognized tax benefits as of December 31	$ 683

German Tax Reform Act 2008

On July 6, 2007, the German government passed the Tax Reform Act of 2008, which reduces the German statutory and resulting effective tax rates on earnings from approximately 36% to approximately 27% effective January 1, 2008. Due to this reduction in the statutory and resulting effective tax rate in 2007, NRG recognized a $29 million tax benefit and as of December 31, 2007, NRG had a German net deferred tax liability of approximately $84 million which includes the impact of this tax rate change.

Note 19 Stock-Based Compensation

In 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 occur. The elimination of unearned compensation and amounts previously recognized in income related to the application of the new forfeiture rate to outstanding instruments as of January 1, 2006 were immaterial to NRG s consolidated statements of operations.

Long-Term Incentive Plan, or LTIP

As of December 31, 2007, a total of 16,000,000 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, new shares of common stock will be issued. There were 7,941,758 shares of common stock remaining available for grants under NRG s LTIP as of December 31, 2007.

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 1.3 million of NRG s outstanding NQSO s, and six years for the remaining 2.3 million NQSO s.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the Company s NQSO activity as of December 31, 2007 and changes during the year then ended:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (In millions)
		(In whole, except weighted average data)		
Outstanding at December 31, 2006	3,411,072	$ 17.59		
Granted	784,350	28.63		
Forfeited	(180,673)	24.29		
Exercised	(434,974)	15.09		
Outstanding at December 31, 2007	3,579,775	$ 19.98	5	$ 84
Exercisable at December 31, 2007	1,917,722	$ 14.57	6	$ 55

The weighted average grant date fair value of options granted during the years ended December 31, 2007, 2006 and 2005 was $8.28, $7.26 and $6.62, respectively. The total intrinsic value of options exercised during the years ended December 31, 2007 and 2006 was $11 million and $1 million, respectively and cash received from the exercise of these options was $7 million and $1 million, respectively. There were no NQSO s exercised during 2005.

The fair value of the Company s NQSO s is estimated on the date of grant using the Black-Scholes option-pricing model. Significant assumptions used in the fair value model for the years ended December 31, 2007, 2006 and 2005 with respect to the Company s NQSO s are summarized below:

	2007	2006	2005
Expected volatility	25.88%-27.28%	27.95%-29.64%	29.75%
Expected dividend yield			
Expected term (in years)	4	4-6	5
Risk free rate	4.58%-4.68%	4.30%-5.05%	4.16%

For 2005 and 2006, expected volatility was calculated based on a blended average of NRG and NRG s industry peers historical two-year stock price volatility data. For 2007, as more historical NRG data has become available, expected volatility is calculated based on NRG s historical stock price volatility data over the period commensurate with the expected term of the stock option. Typically, the expected term for the Company s NQSO s is based on the simple average of the contractual term and vesting term.

Restricted Stock Units, or RSU s

Typically, RSU s granted under the Company s LTIP fully vest three years from the date of issuance. Fair value of the RSU s is based on the closing price of NRG common stock on the date of grant. The following table

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

summarizes the Company s non-vested RSU awards as of December 31, 2007 and changes during the year then ended:

	Units		Weighted Average Grant-Date Fair Value per Unit
	(In whole except weighted average data)		
Non-vested at December 31, 2006	2,277,186	$	15.74
Granted	568,580		38.61
Forfeited	(115,150)		23.29
Vested	(1,142,300)		10.74
Non-vested at December 31, 2007	1,588,316	$	26.99

The total fair value of RSU s vested during the years ended December 31, 2007 and 2006, was $40 million and $11 million, respectively. The total fair value of RSU s vested during the year ended December 31, 2005 was immaterial.

Deferred Stock Units, or DSU s

DSU s represent the right of a participant to be paid one share of NRG common stock at the end of a deferral period established under the terms of the award. DSU s granted under the Company s LTIP are fully vested at the date of issuance. Fair value of the DSU s, which is based on the closing price of NRG common stock on the date of grant, is recorded as compensation expense in the period of grant.

The following table summarizes the Company s outstanding DSU awards as of December 31, 2007 and changes during the year then ended:

	Units		Weighted Average Grant-Date Fair Value per Unit
	(In whole except weighted average data)		
Outstanding at December 31, 2006	280,840	$	16.19
Granted	22,289		44.43
Conversions	(34,135)		19.86
Outstanding at December 31, 2007	268,994	$	18.06

The aggregate intrinsic values for DSU s outstanding as of December 31, 2007, 2006 and 2005 were approximately $12 million, $8 million and $6 million, respectively. The aggregate intrinsic values for DSU s converted to common stock for the years ended December 31, 2007, 2006 and 2005 was $1.2 million, $.4 million and $.3 million, respectively.

Performance Units, or PU s

PU s granted under the Company s LTIP fully vest three to five years from the date of issuance. PU s are paid out upon 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. A Target Price and Maximum Price are determined on the date of issuance. The payout for each PU 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.

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the Company s non-vested PU awards as of December 31, 2007 and changes during the year then ended:

	Outstanding Units		Weighted Average Grant-Date Fair Value per Unit
	(In whole except weighted average data)		
Non-vested at December 31, 2006	410,664	$	18.86
Granted	189,300		22.43
Forfeited	(63,200)		18.35
Non-vested at December 31, 2007	536,764	$	20.18

The weighted average grant date fair value of PU s granted during the years ended December 31, 2007, 2006 and 2005 was $22.43, $17.62 and $14.94, respectively. No PU s have vested under the program as of December 31, 2007.

The fair value of PU s is estimated on the date of grant using a Monte Carlo simulation model and expensed over the service period, which equals the vesting period. Significant assumptions used in the fair value model for the years ended December 31, 2007, 2006 and 2005 with respect to the Company s PU s are summarized below:

	2007	2006	2005
Expected volatility	25.91%-27.28%	27.95%-29.64%	29.75%
Expected dividend payment (in dollars)			
Expected term (in years)	3	3-5	3
Risk free rate	4.54%-4.69%	4.30%-5.04%	4.09%

For 2005 and 2006, expected volatility was calculated based on a blended average of NRG and NRG s industry peers historical two-year stock price volatility data. For 2007, as more historical NRG data has become available, expected volatility is calculated based on NRG s historical stock price volatility data over the period commensurate with the expected term of the PU, which equals the vesting period.

Supplemental Information

The following table summarizes NRG s total compensation expense recognized in accordance with SFAS 123(R) for the years ended December 31, 2007 and 2006, and in accordance with SFAS 123 for the year ended 2005, 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 and the period over which this expense is expected to be recognized as of December 31, 2007. Minimum tax withholdings of $17 million and $5 million paid by the Company during 2007

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and 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 flows.

	Compensation Expense Year Ended December 31			Total Non-Vested Compensation Cost Not Yet Recognized	Weighted Average Life Remaining (In years)
				As of December 31	
Award	**2007**	**2006**	**2005**	**2007**	**2007**
	(In millions, except weighted average data)				
NQSO s	$ 5	$ 5	$ 4	$ 8	0.9
RSU s	10	10	8	27	1.4
DSU s	1	1	3		
PU s	3	2		5	1.4
Total	$ 19	$ 18	$ 15	$ 40	
Tax benefit recognized	$ 8	$ 7	$ 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,	Year Ended December 31,	Year Ended December 31,

	2007	2006 (In millions)	2005
Revenues from Related Parties Included in Operating Revenues			
WCP[(a)]			
O&M fees	$	$ 1	$ 6
AMA fees			2
Gladstone			
O&M fees	1	2	3
MIBRAG			
Consulting fees	4	4	4
Total	$ 5	$ 7	$ 15
Expenses from Related Parties Included in Cost of Operations			
MIBRAG			
Cost of purchased coal	$ 43	$ 43	$ 41

(a) For the period January 1, 2006 to March 31, 2006

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21 Commitments and Contingencies

Operating Lease Commitments

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 $40 million, $37 million and $9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2007 are as follows:

Period	(In millions)	
2008	$	40
2009		38
2010		35
2011		33
2012		31
Thereafter		243
Total	$	420

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 for the years ended December 31, 2007, 2006, and 2005, the Company purchased approximately $1.7 billion, $1.8 billion and $0.7 billion, respectively, under such arrangements.

As of December 31, 2007, the Company s commitments under such outstanding agreements are estimated as follows:

Period	(In millions)	
2008	$	1,614
2009		795
2010		264
2011		150

2012		149
Thereafter		231
Total[a]	$	3,203

(a) Includes only those coal transportation commitments for 2008 as no other nominations were made as of December 31, 2007.

Lignite Contract with Texas Westmoreland Coal Co.

The lignite used to fuel the Texas region s Limestone facility is obtained from a surface mine, or the Jewett mine, adjacent to the facility under an amended long-term contract with TWCC, originally entered into in 1979. In June 2007, TWCC notified NRG of their election to deliver zero tons of lignite from the Jewett Mine for 2008,

NRG ENERGY, INC. AND SUBSIDIARIES

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effectively ending TWCC s rights to deliver lignite from the Jewett Mine per the long-term contract after December 31, 2007. During the third quarter of 2007, NRG and TWCC renegotiated a long-term contract that has significantly changed the contractual structure as well as extended the mining period. The new contract is based on a cost-plus arrangement with incentives and penalties to ensure proper management of the mine. NRG has flexibility to increase or decrease lignite purchases from the mine within certain ranges, including the ability to suspend or terminate lignite purchases with adequate notice. The mining period has been extended through 2018 with an option to extend the mining period by two five-year intervals.

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

The Railroad Commission of Texas has imposed a bond obligation of approximately $83 million on TWCC for the reclamation of this lignite mine. Pursuant to the contract with TWCC, an affiliate of CenterPoint Energy, Inc. has guaranteed $50 million of this obligation. The remaining sum of approximately $33 million has been bonded by the mine operator, TWCC. Approximately $7 million of such amount is supported by a letter of credit posted by NRG. Under the terms of the new cost plus agreement with TWCC, NRG is required to maintain a corporate guarantee of TWCC s bond obligation in the amount of $50 million if CenterPoint Energy, Inc. s obligation lapses, or pay the costs of obtaining replacement performance assurance. Additionally, NRG is required to provide additional performance assurance over TWCC s current bond obligations if required by the Commission.

International Commitments

Two of the Company s wholly-owned, indirect subsidiaries are severally responsible for the pro rata 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, 2007, the Company was obligated for the loan of AUD 42 million (approximately US $37 million) in principal. This loan is scheduled to be fully repaid on March 31, 2009.

First and Second Lien Structure

NRG has granted first and second priority liens to certain counterparties on substantially all of the Company s assets in the United States in order to secure certain obligations, which are primarily long-term in nature under certain power sale agreements and related contracts. NRG uses the first or second lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under these agreements. Within the first and second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties.

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

On October 30, 2007, NRG successfully moved certain second lien holders to a pari passu basis with the Company s first lien lenders effectively releasing $557 million of letters of credit. With the movement to the first lien structure, the Company has significantly reduced its outstanding letter of credit exposure and thereby increased its liquidity. As of December 31, 2007, the net discounted exposure on the agreements and hedges that were subject to the first and second lien structure was approximately $425 million.

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RepoweringNRG Project Deposit

NRG has made non-refundable deposits relating to *Repowering*NRG initiatives totaling approximately $71 million primarily towards the procurement of wind turbines. The Company believes that these deposits are necessary for the timely and successful execution of these projects. The deposits are in support of expected deliveries of wind turbines and other equipment totaling approximately $409 million through 2009. Although NRG is committed to their successful implementation, the Company may decide not to take delivery of the equipment and thus terminate the projects. This would result in the Company expensing the deposits it already has made.

On February 4, 2008, NRG through its wholly owned subsidiary, Padoma Wind Power LLC, had entered into a 50-50 joint venture with BP Alternative Energy North America Inc. to build the first phase of the Sherbino Wind Farm. The Sherbino I Wind Farm will be a 150-megawatt (MW) wind project, consisting of 50 Vestas 3 MW wind turbine generators, located approximately 40 miles east of Fort Stockton in Pecos County, Texas. NRG expects to contribute approximately $83 million in equity to the joint venture in 2008 and has posted a letter of credit in that amount.

Contingencies

Set forth below is a description of the Company s material legal proceedings. Pursuant to the requirements of SFAS No. 5, *Accounting for Contingencies,* or SFAS 5, and related guidance, NRG records reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments could occur, there can be no certainty that NRG may not ultimately incur charges in excess of presently recorded reserves. A future adverse ruling or unfavorable development could result in future charges, which could have a materially adverse effect on NRG s consolidated financial position, results of operations, or cash flows.

With respect to a number of the items listed below, management has determined that a loss is not probable or the amount of the loss is not reasonably estimable, or both. In some cases, management is not able to predict with any degree of substantial certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed each of these matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Management s judgment may, as a result of facts arising prior to resolution of these matters, or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the uncertainty of litigation.

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely effect NRG s consolidated financial position, results of operations, or cash flows.

NRG believes that it has valid defenses to the legal proceedings and investigations described below and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future, asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified below, the Company is unable to predict the outcome that these legal proceedings and investigations or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company s consolidated financial position, results of operations, or cash flows. NRG also has indemnity rights for some of these proceedings to reimburse NRG for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

California Electricity and Related Litigation

NRG, WCP, WCP s four operating subsidiaries, Dynegy, Inc., and numerous other unrelated parties are the subject of lawsuits that arose based on events that occurred in the California power market in 2000 and 2001. The

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market gaming activities. Other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential 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. Discovery is proceeding in these cases. In October 2007, Dynegy reached a tentative settlement of all remaining coordinated natural gas index cases pending in state court in San Diego. The settlement has yet to be funded by Dynegy and requires court approval which is underway. If approved, neither WCP and its subsidiaries nor NRG would pay any settlement costs as Dynegy owed and continues to provide a complete defense and indemnification.

In cases relating to natural gas, Dynegy is defending WCP and/or its subsidiaries pursuant to an indemnification agreement and will be the responsible party for any loss. There are no further cases related to electricity, but should any new cases arise, Dynegy s counsel would represent it and WCP and/or its subsidiaries, with each party responsible for half of the costs and each party responsible for half of any loss.

California Department of Water Resources

On December 19, 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the Federal Energy Regulatory Commission s, or FERC s, prior determinations regarding the enforceability of certain wholesale power contracts and remanded the case to FERC for further proceedings consistent with the decision. One of these contracts was the wholesale power contract between the California Department of Water Resources, or CDWR, and subsidiaries of WCP. This case originated with a February 2002 complaint filed at FERC by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, FERC rejected this complaint, denied rehearing, and the case was appealed to the Ninth Circuit where oral argument was held on December 8, 2004. On December 19, 2006, the Court decided that in FERC s review of the contracts at issue, FERC could not rely on the Mobile-Sierra standard presumption of just and reasonable rates, where such contracts were not reviewed by FERC with full knowledge of the then existing market conditions. On May 3, 2007, WCP and the other defendants filed separate petitions for certiorari seeking review by the U.S. Supreme Court and on September 25, 2007, the Court agreed to hear two of the filed petitions. Although WCP s petition was not selected for review, the Court s ultimate decision with respect to the other defendants petitions will apply equally to WCP. Oral argument occurred on February 19, 2008, and a decision is expected from the Court by the end of 2008. At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG s financial position, statement of operations, and statement of cash flows. As part of the 2006 acquisition of Dynegy s 50% ownership interest in WCP, WCP and NRG assumed responsibility for any risk of loss arising from this case, unless any such loss was deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally between WCP and Dynegy.

Station Service Disputes

On October 2, 2000, Niagara Mohawk Power Corporation, or NiMo, commenced an action against NRG in New York state court seeking damages related to NRG s alleged failure to pay retail tariff amounts for utility services at the Dunkirk plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego plants. On October 8, 2002, by stipulation and order, this action was stayed pending submission to FERC of the disputes in the action. At FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo s petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the

NRG ENERGY, INC. AND SUBSIDIARIES

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facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on June 23, 2006, denied the appeal finding that New York Independent System Operator s, or NYISO s, station service program that permits generators to self supply their station power needs by netting consumption against production in a month is lawful. On April 30, 2007, the U.S. Supreme Court denied NiMo s request for review of the D.C. Circuit decision thus ending further avenues to appeal FERC s ruling in this matter. NRG believes it is adequately reserved.

On December 14, 1999, NRG acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an order finding that, at times when NRG is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration. On September 11, 2007, the parties argued the dispute before a three judge arbitration panel. On February 19, 2008, the parties executed a settlement agreement ending the arbitration. A component of the settlement requires approval from ISO-NE. Our accrual was reversed into income consistent with the settlement.

Spring Creek Coal Company

In August 2007, Spring Creek Coal Company filed a complaint against NRG Texas LP, NRG South Texas LP, NRG Texas Power LLC, NRG Texas LLC, and NRG Energy, Inc. in the U.S. District Court for the federal district of Wyoming. The complaint alleges multiple breaches in 2007 of a 1978 coal supply agreement as amended by a later 1987 agreement, which plaintiff alleges is a take or pay contract. Damages of approximately $18 million are being sought. Certain of the defendants have filed a motion to dismiss for lack of personal jurisdiction and certain other defendants have filed a motion to dismiss for lack of a case in controversy. The court will hear these and other motions on July 11, 2008. The trial is scheduled to begin on September 8, 2008.

Native Village of Kivalina and City of Kivalina

Numerous electric generating companies and oil and gas companies have been named as defendants in this complaint, which has been filed but not yet served on NRG. Damages of up to $400 million have been asserted. The complaint alleges that the carbon dioxide emissions of defendants contribute to global climate change which has harmed the plaintiffs. The complaint is filed on behalf of an Alaskan town made up of native tribes and seeks damages associated with those tribes having to relocate from the northern coast of Alaska, purportedly because of the effects of global warming.

Disputed Claims Reserve

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

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company s Chapter 11 bankruptcy plan, totaling $25 million in cash and 5,082,000 shares of common stock. As of February 7, 2008, the

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reserve held approximately $10 million in cash and approximately 1,317,138 shares of common stock on a post-stock split basis. NRG believes the cash and stock together represent sufficient funds to satisfy all remaining disputed claims.

Note 22 Regulatory Matters

NRG operates in a highly regulated industry and the Company is subject to regulation by various federal and state agencies. As such, NRG is affected by regulatory developments at both the federal and state levels and in the regions in which NRG operates. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO markets in which NRG participates. These wholesale power markets are subject to ongoing legislative and regulatory changes.

Northeast Region

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

On December 28, 2006, the Attorney General of the State of Connecticut and Commonwealth of Massachusetts filed an appeal of the FERC orders accepting the settlement of the New England capacity market design with the U.S. Court of Appeals for the D.C. Circuit. The settlement, filed with FERC on March 7, 2006, by a broad group of New England market participants, provides for interim capacity transition payments for all generators in New England for the period starting December 1, 2006 through May 31, 2010, and the establishment of a 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. Oral argument was held on February 14, 2008.

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

On December 18, 2007, the U.S. Court of Appeals for the D.C. Circuit denied the appeals relating to the 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 had argued that the NYISO acted unreasonably in declining to invoke Temporary Extraordinary Operating Procedures, or TEP, to recalculate prices

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and that the markets should be resettled for various reasons. In a series of orders, FERC had declined to grant the requested relief, explaining that (i) the NYISO acted reasonably in not invoking TEP, (ii) NYISO did not violate its tariff, and (iii) refunds should not be granted as they would be disruptive to settled market expectations. The Court s December 18, 2007 order is expected to conclude this matter.

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.

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

On January 15, 2008, the Maryland Public Service Commission, or MDPSC, filed at FERC a complaint against PJM claiming that PJM had failed to adequately mitigate certain generation resources, due to exemptions for resources used to relieve reactive limits on interfaces or that were constructed during certain periods after 1999. In addition to seeking an order eliminating the exemptions and a refund effective date as of the date of the complaint, the MDPSC is also seeking an investigation of periods prior to the complaint that could lead to disgorgement by certain entities, and possibly a resettlement of the market back to September 8, 2006. The principal impacts on NRG would occur as a resettlement of the LMPs, which is not viewed as likely at this time, and going-forward in the form of lower LMPs. In addition, NRG s peaking units at its energy center in Dover, Delaware were built in 2001 and utilize the post-1999 bidding exemption.

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

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2008 through 2012 to meet NRG s environmental commitments will be between $1.0 billion and

$1.4 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with Clean Air Interstate Rule, or CAIR, the Clean Air Mercury Rule, or CAMR, and related state requirements as well as installation of Best Technology Available under the Phase II 316(b) rule. NRG continues to explore cost effective alternatives that can achieve desired results. The range reflects alternative strategies available with respect to the Company s Indian River plant.

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Northeast Region

In January 2006, NRG s 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. On October 1, 2007, NRG filed a Facility Evaluation with DNREC, through the Voluntary Clean-up Program to investigate the site. DNREC responded to the Facility Evaluation on February 4, 2008 finding no further action is required in relation to surface water and that a previously planned shoreline stabilization project would adequately address shore line erosion. The landfill itself will require a further Remedial Investigation and Feasibility Study to determine the type and scope of any additional work required. Until the Remedial Investigation and Feasibility Study is completed, the Company is unable to predict the impact of any required remediation.

In November 2006, DNREC, promulgated Regulation No. 1146, or Reg 1146, Electric Generating Unit Multi-Pollutant Regulation and Section 111(d) of the State Plan for the Control of Mercury Emissions from Coal-Fired Electric Steam Generating Units. These regulations govern the control of SO_2, NO_x, and mercury emissions from electric generating units. NRG s plan to install controls at the Company s Indian River facility, while on an accelerated basis, was unable to meet certain deadlines, taking into account the time required, as a practical matter, to design, install and commission the necessary equipment. NRG filed a challenge to Reg 1146 with the Environmental Appeals Board, or EAB, on December 6, 2006. In addition, NRG also filed a protective appeal with the Delaware Superior Court on December 29, 2006. This challenge was settled when DNREC and NRG signed a Consent Order on September 25, 2007, and filed that document with the Delaware Superior Court thereby ending the case. Under this agreement, continued operations at the Company s Indian River Generating Station are conditioned upon installation of controls on Units 1 and 2 by May 1, 2008, to reduce NO_x; installation of controls on Units 1-4 by January 1, 2009 to meet mercury requirements; mothball of Units 1 and 2 by May 1, 2011, and May 1, 2010, respectively; and installation of advanced controls on Units 3 and 4 in 2011 to further reduce NO_x and SO_2. If the plant emits NO_x in excess of 1,700 tons in any given ozone season, it will be subject to a graduated scale of stipulated penalties, up to a maximum $2,500/ton. The capital costs associated with this settlement are included in the Company s estimated environmental capital expenditures. In the absence of the appropriate control technology installed at this facility, Units 3 and 4 totaling approximately 565 MW, could not operate beyond December 31, 2011, per terms of the Consent Order.

South Central Region

On January 27, 2004, NRG s Louisiana Generating, LLC and the Company s Big Cajun II plant received a request under Section 114 of the Clean Air Act from the United States Environmental Protection Agency, or USEPA, seeking information primarily related to physical changes made at the Big Cajun II plant, and subsequently received a notice of violation, or NOV, on February 15, 2005, alleging that NRG s predecessors had undertaken projects that triggered requirements under the Prevention of Significant Deterioration program, including the installation of emission controls. NRG submitted multiple responses commencing February 27, 2004 and ending on October 20, 2004. On May 9, 2006, these entities received from the Department of Justice, or DOJ, a Notice of Deficiency related to their responses, to which NRG responded on May 22, 2006. A document review was conducted at NRG s Louisiana Generating, LLC offices by the DOJ during the week of August 14, 2006. On December 8, 2006, the USEPA issued a supplemental NOV updating the original February 15, 2005 NOV. Discussions with the USEPA are ongoing and the Company cannot predict with certainty the outcome of this matter.

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Note 24 Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In millions)	
Interest paid, net of amount capitalized	$ 598	$ 450	$ 257
Income taxes paid[(a)]	22	18	21
Non-cash investing and financing activities:			
Addition to fixed assets due to asset retirement obligations	7	15	4
Addition to treasury stock for the maximum purchase price adjustment			8

(a) 2007 income taxes paid is net of $6 million federal tax refund received.

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 $9 million as of December 31, 2007, 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, 2007					
Guarantees	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total**	**2006 Total**
			(In millions)			

Synthetic letters of credit	$ 475	$ 268	$	$	$ 743	$ 967
Unfunded letters of credit and surety bonds	8				8	153
Asset sales guarantee obligations	13		113	22	148	144
Commercial sales arrangements	93	134		564	791	604
Other guarantees				32	32	29
Total guarantees	$ 589	$ 402	$ 113	$ 618	$ 1,722	$ 1,897

Letters of credit and surety bonds As of December 31, 2007, NRG and its consolidated subsidiaries were contingently obligated for a total of approximately $751 million under letters of credit and surety bonds. Most of these letters of credit and surety bonds 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 and surety bonds expire within one year of issuance, and it is typical for the Company to renew them on similar terms.

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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 December 18, 2007, NRG entered into a share and purchase agreement to sell its 100% interest in Tosli to Brookfield Power Inc. NRG has guaranteed the payment and performance of its wholly owned subsidiary s Sterling Luxemburg (No. 4) obligations under the share and purchase agreement. The maximum liability of NRG is limited to the sale price of $288 million.

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, performance under purchase, EPC and operating and maintenance agreements. In 2007, NRG executed a guarantee related to its obligations as construction manager under its agreements related to a wind farm project. In addition, NRG entered into a guarantee under an EPC contract related to a repowering project. The Company does not believe that it will be required to perform under this guarantee.

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 $288 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.

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 direct expenses in these jointly-owned plants in the corresponding balance sheet, and income statement captions of the Company s consolidated financial statements.

The following table summarizes NRG s proportionate ownership interest in the Company s jointly-owned facilities as of December 31, 2007:

As of December 31, 2007	Ownership Interest	Property, Plant & Equipment	Accumulated Depreciation	Construction in Progress
		(In millions unless otherwise stated)		
South Texas Project Units 1 and 2, Bay City, TX	44.00%	$ 2,914	$ (345)	$ 19
Big Cajun II Unit 3, New Roads, LA	58.00	173	(39)	10
Cedar Bayou Unit 4, Baytown, TX	50.00			71
Keystone, Shelocta, PA	3.70	61	(12)	6
Conemaugh, New Florence, PA	3.72	72	(15)	1

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 27 Unaudited Quarterly Financial Data

Summarized unaudited quarterly financial data is as follows:

	Quarter Ended 2007			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 1,382	$ 1,772	$ 1,536	$ 1,299
Operating income	320	546	427	267
Income from continuing operations, net of income taxes	100	265	143	61
Income from discontinued operations, net of income taxes	4	3	6	4
Net income	$ 104	$ 268	$ 149	$ 65
Weighted average number of common shares outstanding basic	239	239	240	244
Income from continuing operations per weighted average common share basic	$ 0.36	$ 1.06	$ 0.54	$ 0.19
Income from discontinued operations per weighted average common share basic	$ 0.02	$ 0.01	$ 0.02	$ 0.02
Net income per weighted average common share basic	$ 0.38	$ 1.07	$ 0.56	$ 0.21
Weighted average number of common shares outstanding diluted	270	285	288	271
Income from continuing operations per weighted average common share diluted	$ 0.34	$ 0.92	$ 0.49	$ 0.19
Income from discontinued operations per weighted average common share diluted	0.01	0.01	0.02	0.01
Net income per weighted average common share diluted	$ 0.35	$ 0.93	$ 0.51	$ 0.20

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Quarter Ended 2006			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 1,135	$ 1,932	$ 1,492	$ 1,026
Operating income	96	713	404	205
Income/(loss) from continuing operations, net of income taxes	(35)	367	198	13
Income from discontinued operations, net of income taxes	5	55	5	13
Net income/(loss)	$ (30)	$ 422	$ 203	$ 26
Weighted average number of common shares outstanding basic	250	272	274	235
Income/(loss) from continuing operations per weighted average common share basic	$ (0.19)	$ 1.30	$ 0.67	$ 0.01
Income/(loss) from discontinued operations per weighted average common share basic	0.02	0.20	0.02	0.05
Net income/(loss) per weighted average common share basic	$ (0.17)	$ 1.50	$ 0.69	$ 0.06
Weighted average number of common shares outstanding diluted	250	317	319	238
Income/(loss) from continuing operations per weighted average common share diluted	$ (0.19)	$ 1.15	$ 0.61	$ 0.01
Income from discontinued operations per weighted average common share diluted	0.02	0.17	0.02	0.05
Net income/(loss) per weighted average common share diluted	$ (0.17)	$ 1.32	$ 0.63	$ 0.06

Note 28 Condensed Consolidating Financial Information

As of December 31, 2007, the Company had $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016 and $1.1 billion 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, 2007:

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Cabrillo Power I LLC

NRG Construction LLC
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Generation Holdings, Inc.

Cabrillo Power II LLC
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

El Segundo Power, LLC
El Segundo Power II LLC
GCP Funding Company, LLC
Hanover Energy Company
Hoffman Summit Wind Project, LLC
Huntley IGCC LLC
Huntley Power LLC
Indian River IGCC LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Lake Erie Properties Inc.
Louisiana Generating LLC
Middletown Power LLC
Montville IGCC LLC
Montville Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP, LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Cedar Bayou Development Company, LLC
NRG Connecticut Affiliate Services Inc
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 LLC
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG Texas LLC
NRG Texas Power LLC
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Padoma Wind Power, LLC
Saguaro Power LLC
San Juan Mesa Wind Project II, LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services, LLC
Texas Genco Services, LP
Vienna Operations Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

The non-guarantor subsidiaries include all of NRG s foreign subsidiaries and certain domestic subsidiaries. NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company s ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG s ability to receive funds from its subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under the Company s Peaker financing agreements,

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2007

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations[a]	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 5,614	$ 375	$	$	$ 5,989
Operating Costs and Expenses					
Cost of operations	3,131	247			3,378
Depreciation and amortization	630	24	4		658
General and administrative	101	19	189		309
Development costs	66	2	33		101
Total operating costs and expenses	3,928	292	226		4,446
Gain/(loss) on sale of assets	18		(1)		17
Operating Income/(Loss)	1,704	83	(227)		1,560
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	204		986	(1,190)	
Equity in earnings of unconsolidated affiliates	(3)	57			54
Gain on sale of equity method investments		1			1
Other income, net	9	13	33		55
Refinancing expenses			(35)		(35)
Interest expense	(250)	(64)	(375)		(689)
Total other income/(expense)	(40)	7	609	(1,190)	(614)
Income From Continuing Operations Before Income Taxes	1,664	90	382	(1,190)	946
Income tax expense/(benefit)	576	5	(204)		377
Income From Continuing Operations	1,088	85	586	(1,190)	569
Income from discontinued operations, net of income taxes		17			17

Net Income	$ 1,088	$ 102	$ 586	$ (1,190)	$ 586

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2007

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy Inc. (In millions)	Eliminations[a]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ (4)	$ 124	$ 1,012	$	$ 1,132
Restricted cash	1	28			29
Accounts receivable-trade, net	445	37			482
Inventory	439	12			451
Deferred income taxes	139	(18)	3		124
Derivative instruments valuation	1,034				1,034
Collateral on deposit in support of energy risk management activities	85				85
Prepayments and other current assets	96	35	195	(152)	174
Current assets discontinued operations		51			51
Total current assets	2,235	269	1,210	(152)	3,562
Net Property, Plant and Equipment	10,828	470	22		11,320
Other Assets					
Investment in subsidiaries	610		9,787	(10,397)	
Equity investments in affiliates	28	397			425
Notes receivable	360	126	3,779	(4,139)	126
Capital lease, less current portion		365			365
Goodwill	1,786				1,786
Intangible assets, net	859	14			873
Intangible assets held-for-sale	14				14
Nuclear decommissioning trust fund	384				384
Derivative instruments valuation	150				150

Other non-current assets		11		1		164				176
Non-current assets discontinued operations				93						93
Total other assets		4,202		996		13,730		(14,536)		4,392
Total Assets	$	17,265	$	1,735	$	14,962	$	(14,688)	$	19,274

LIABILITIES AND STOCKHOLDERS EQUITY

Current Liabilities										
Current portion of long-term debt and capital leases	$	83	$	282	$	184	$	(83)	$	466
Accounts payable trade		(699)		352		731				384
Derivative instruments valuation		916		1						917
Accrued expenses and other current liabilities		335		62		145		(69)		473
Current liabilities discontinued operations				37						37
Total current liabilities		635		734		1,060		(152)		2,277
Other Liabilities										
Long-term debt and capital leases		3,773		571		7,690		(4,139)		7,895
Nuclear decommissioning reserve		307								307
Nuclear decommissioning trust liability		326								326
Deferred income taxes		598		(138)		383				843
Derivative instruments valuation		690		16		53				759
Non-current out-of-market contracts		628								628
Other non-current liabilities		377		10		25				412
Non-current liabilities discontinued operations				76						76
Total non-current liabilities		6,699		535		8,151		(4,139)		11,246
Total liabilities		7,334		1,269		9,211		(4,291)		13,523
3.625% Preferred Stock						247				247
Stockholders Equity		9,931		466		5,504		(10,397)		5,504
Total Liabilities and Stockholders Equity	$	17,265	$	1,735	$	14,962	$	(14,688)	$	19,274

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2007

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations[a]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 1,088	$ 102	$ 586	$ (1,190)	$ 586
Adjustments to reconcile net income to net cash provided/(used) by operating activities					
Distributions in excess/(less than) equity in earnings of unconsolidated affiliates	101	(36)	(684)	586	(33)
Depreciation and amortization of nuclear fuel	688	27	4		719
Amortization and write-of of deferred financing costs and debt discount/premiums		6	60		66
Amortization of intangibles and out-of-market contracts	(160)	4			(156)
Amortization of unearned equity compensation			19		19
Gains on sale of equity method investments		(1)			(1)
(Gain)/loss on sale assets	(18)		1		(17)
Impairment charges and asset write downs	9		11		20
Changes in derivatives	77				77
Changes in deferred income taxes	112	(31)	271		352
Gain on sale of emission allowances	(30)	(1)			(31)
Change in nuclear decommissioning trust liability	32				32
Changes in collateral deposits supporting energy risk management activities	(125)				(125)
Cash provided/(used) by changes in other working capital, net of disposition affects	214	100	(305)		9
Net Cash Provided by Operating Activities	1,988	170	(37)	(604)	1,517
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	655		2,109	(2,764)	
Capital expenditures	(389)	(84)	(8)		(481)
Decrease in restricted cash, net		12			12
Decrease in notes receivable		34			34
Decrease in trust fund balances	19				19

Purchases of emission allowances	(161)				(161)
Proceeds from sale of emission allowances	271	1			272
Investments in nuclear decommissioning trust fund securities	(265)				(265)
Proceeds from sales of nuclear decommissioning trust fund securities	233				233
Proceeds from sale of investment and equipment		2			2
Purchase of securities			(49)		(49)
Proceeds from sale of discontinued operations and assets	29		28		57
Net Cash Provided/(Used) by Investing Activities	392	(35)	2,080	(2,764)	(327)
Cash Flows from Financing Activities					
Payment of dividends to preferred stockholders			(55)		(55)
Payment for treasury stock			(353)		(353)
Payments from intercompany loans	(2,101)	(38)	(625)	2,764	
Payments from intercompany dividends	(302)	(302)		604	
Proceeds from issuance of common stock			7		7
Proceeds from issuance of long-term debt			1,411		1,411
Payment of deferred debt issuance costs			(5)		(5)
Payments of short and long-term debt	(1)	(64)	(1,754)		(1,819)
Net Cash Provided/(Used) by Financing Activities	(2,404)	(404)	(1,374)	3,368	(814)
Change in cash from discontinued operations		(25)			(25)
Effect of exchange rate changes on cash and cash equivalents		4			4
Net Increase/(decrease) in Cash and Cash Equivalents	(24)	(290)	669		355
Cash and Cash Equivalents at Beginning of Period	20	414	343		777
Cash and Cash Equivalents at End of Period	$ (4)	$ 124	$ 1,012	$	$ 1,132

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

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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	$ 303	$	$	$ 5,585
Operating Costs and Expenses					
Cost of operations	3,040	223	2		3,265
Depreciation and amortization	562	23	5		590
General and administrative	83	13	180		276
Development costs	32		4		36
Total operating costs and expenses	3,717	259	191		4,167
Operating Income/(Loss)	1,565	44	(191)		1,418
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 gains/(losses) on sales of equity method investments	(5)	13			8
Other income, net	20	115	41	(20)	156
Refinancing expenses			(187)		(187)
Interest expense	(232)	(56)	(322)	20	(590)
Total other income/(expense)	(81)	130	528	(1,130)	(553)
Income From Continuing Operations Before Income Taxes	1,484	174	337	(1,130)	865
Income tax expense	549	42	(269)		322
Income From Continuing Operations	935	132	606	(1,130)	543
Income from discontinued operations, net of income taxes		63	15		78
Net Income	$ 935	$ 195	$ 621	$ (1,130)	$ 621

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

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

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy Inc. (In millions)	Eliminations[a]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 20	$ 414	$ 343	$	$ 777
Restricted cash	1	40			41
Accounts receivable-trade, net	332	37			369
Inventory	408	12			420
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	33	736	(747)	195
Current assets discontinued operations		24			24
Total current assets	2,191	560	1,079	(747)	3,083
Net Property, Plant and Equipment	11,178	349	19		11,546
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
Non-current assets discontinued operations		82			82
Total other assets	5,447	907	14,864	(16,411)	4,807

Total Assets	$	18,816	$	1,816	$	15,962	$	(17,158)	$	19,436

LIABILITIES AND STOCKHOLDERS EQUITY

Current Liabilities										
Current portion of long-term debt and capital leases	$	460	$	94	$	37	$	(468)	$	123
Accounts payable trade		(682)		284		727				329
Derivative instruments valuation		964								964
Deferred income taxes		23		7		134				164
Accrued expenses and other current liabilities		509		35		160		(280)		424
Current liabilities discontinued operations				28						28
Total current liabilities		1,274		448		1,058		(748)		2,032
Other Liabilities										
Long-term debt and capital leases		5,504		825		8,791		(6,517)		8,603
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		8		24				417
Non-current liabilities discontinued operations				64						64
Total non-current liabilities		8,218		799		8,999		(6,517)		11,499
Total liabilities		9,492		1,247		10,057		(7,265)		13,531
Minority Interest										
3.625% Preferred Stock						247				247
Stockholders Equity		9,324		569		5,658		(9,893)		5,658
Total Liabilities and Stockholders Equity	$	18,816	$	1,816	$	15,962	$	(17,158)	$	19,436

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

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
Year Ended December 31, 2006

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations[a]	Consolidated Balance
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
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 in restricted cash, net	2	4			6
Decrease 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 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		1	1		2

Effect of exchange rate changes on cash and cash equivalents		4			4
Net Increase/(decrease) in Cash and Cash Equivalents	27	343	(79)		291
Cash and Cash Equivalents at Beginning of Period	(7)	71	422		486
Cash and Cash Equivalents at End of Period	$ 20	$ 414	$ 343	$	$ 777

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

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NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATING STATEMENTS OF OPERATIONS
Year Ended December 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (In millions)	Eliminations[a]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 2,095	$ 310	$	$ (5)	$ 2,400
Operating Costs and Expenses					
Cost of operations	1,600	234		(5)	1,829
Depreciation and amortization	133	20	5		158
General and administrative	39	14	123		176
Other charges	6		6		12
Total operating costs and expenses	1,778	268	134	(5)	2,175
Operating Income/(Loss)	317	42	(134)		225
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	46	13	(21)	54
Refinancing expense		1	(66)		(65)
Interest expense	(1)	(56)	(141)	21	(177)
Total other income	104	76	80	(375)	(115)
Income/(Loss) From Continuing Operations Before Income Taxes	421	118	(54)	(375)	110
Income tax expense/(benefit)	155	17	(130)		42
Income From Continuing Operations	266	101	76	(375)	68
Income from discontinued operations, net of income taxes	5	3	8		16
Net Income	$ 271	$ 104	$ 84	$ (375)	$ 84

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

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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 in restricted cash, net	1	44			45
Decrease 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		36	1		37
Effect of exchange rate changes on cash and cash equivalents		(2)			(2)
Change in Cash and Cash equivalents	(163)	(117)	(289)		(569)
Cash and Cash Equivalents at Beginning of Period	156	188	711		1,055
Cash and Cash Equivalents at End of Period	$ (7)	$ 71	$ 422	$	$ 486

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

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NRG ENERGY, INC.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2007, 2006, and 2005

	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, 2007	$ 1	$	$	$	$ 1
Year ended December 31, 2006	2			(1)	1
Year ended December 31, 2005	1	2		(1)	2
Income tax valuation allowance, deducted from deferred tax assets					
Year ended December 31, 2007	$ 581	$ 6	$ 8	$ (56)	$ 539
Year ended December 31, 2006	836	(10)	(81)	(164)	581
Year ended December 31, 2005	788	22	85	(59)	836

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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, 2008

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POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints David W. Crane, J. Andrew Murphy, Tanuja M. Dehne and Brian Curci, 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, 2008.

Signature	Title	Date
/s/ David W. Crane David W. Crane	President, Chief Executive Officer and Director	February 28, 2008
/s/ Howard E. Cosgrove Howard E. Cosgrove	Chairman of the Board	February 28, 2008
/s/ John F. Chlebowski John F. Chlebowski	Director	February 28, 2008
/s/ Lawrence S. Coben Lawrence S. Coben	Director	February 28, 2008
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 28, 2008
/s/ William E. Hantke William E. Hantke	Director	February 28, 2008
/s/ Paul W. Hobby Paul W. Hobby	Director	February 28, 2008
/s/ Maureen Miskovic	Director	February 28, 2008

Maureen Miskovic		
/s/ Anne C. Schaumburg	Director	February 28, 2008
Anne C. Schaumburg		
/s/ Herbert H. Tate	Director	February 28, 2008
Herbert H. Tate		
/s/ Thomas H. Weidemeyer	Director	February 28, 2008
Thomas H. Weidemeyer		
/s/ Walter R. Young	Director	February 28, 2008
Walter R. Young		

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.(5)
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.(5)
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.(11)
3.1	Amended and Restated Certificate of Incorporation.(16)
3.2	Amended and Restated By-Laws.(1)
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.(7)
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.(17)
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.(19)
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.(27)
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.(27)
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.(13)
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.(6)
4.7	Specimen of Certificate representing common stock of NRG Energy, Inc.(26)
4.8	Indenture, dated February 2, 2006, among NRG Energy, Inc. and Law Debenture Trust Company of New York.(19)
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.(20)

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.(20)
4.11	Form of 7.250% Senior Note due 2014.(20)
4.12	Form of 7.375% Senior Note due 2016.(20)

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.(22)
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.(22)
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.(23)
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.(23)
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.(28)
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.(28)
4.19	Ninth Supplemental Indenture, dated November 13, 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.(29)
4.20	Tenth Supplemental Indenture, dated July 19, 2007, 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.(33)
4.21	Eleventh Supplemental Indenture, dated July 19, 2007, 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.(33)
4.22	Twelfth Supplemental Indenture, dated July 19, 2007, 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.(33)
4.23	Thirteenth Supplemental Indenture, dated August 28, 2007, 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.(34)
4.24	Fourteenth Supplemental Indenture, dated August 28, 2007, 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.(34)
4.25	Fifteenth Supplemental Indenture, dated August 28, 2007, 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.(34)
4.26	Form of 7.375% Senior Note due 2017.(29)
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*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.(15)
10.4*	Form of NRG Energy, Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.(15)

10.5*	Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.(8)
10.6*	Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.(8)
10.7*	Form of NRG Energy, Inc. Long Term Incentive Plan Performance Unit Agreement.(15)

10.8*	Annual Incentive Plan for Designated Corporate Officers.(9)
10.9*	Letter Agreement, dated February 19, 2004, between NRG Energy, Inc. and Robert C. Flexon.(8)
10.10	Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(15)
11.11	Commitment Letter, dated February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(15)
10.12	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.(14)
10.13	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.(14)
10.14*	Letter Agreement, dated June 21, 2005, between NRG Energy, Inc. and Kevin T. Howell.(18)
10.15	Stock Purchase Agreement, dated as of August 10, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(17)
10.16	Accelerated Share Repurchase Agreement, dated as of August 11, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(17)
10.17	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.(21)
10.18	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).(25)
10.19*	Employment Agreement, dated March 3, 2006, between NRG Energy, Inc. and David Crane.(25)
10.20*	CEO and CFO Compensation Table.(30)
10.21*	NRG Energy, Inc. Director Compensation Table.(24)
10.22	Limited Liability Company Agreement of NRG Common Stock Finance I LLC.(27)
10.23	Limited Liability Company Agreement of NRG Common Stock Finance II LLC.(27)
10.24	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC.(27)
10.25	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.(27)
10.26	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.(27)
10.27	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.(27)
10.28	Common Interest Purchase Agreement, dated August 4, 2006, between NRG Energy, Inc. and NRG Common Stock Finance I LLC.(27)
10.29	Common Interest Purchase Agreement, dated August 4, 2006, between NRG Energy, Inc. and NRG Common Stock Finance II LLC.(27)
10.30	Second Amended and Restated Credit Agreement, dated June 8, 2007, by and among NRG Energy, Inc., the lenders party thereto, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Citicorp North America Inc. and Credit Suisse.(32)
10.31	Credit Agreement dated June 8, 2007 by and among NRG Holdings, Inc., the lenders party thereto, Credit Suisse Securities (USA) LLC, Credit Suisse and Citigroup Global Markets Inc.(32)
10.32*	Amended and Restated Long-Term Incentive Plan, dated December 8, 2006.(31)
10.33*	Named Executive Officer Compensation.(1)
10.34*	NRG Energy, Inc. Executive and Key Management Change-in-Control and General Severance Agreement, dated May 24, 2006.(31)
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)

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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 current report on Form 8-K filed on November 19, 2003.

(6) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 27, 2004.

(7) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 27, 2004.

(8) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q for the quarter ended September 30, 2004.

(9) Incorporated herein by reference to NRG Energy, Inc. s 2004 proxy statement on Schedule 14A filed on July 12, 2004.

(10) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q for the quarter ended March 31, 2004.

(11) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on October 3, 2005.

(12) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q for the quarter ended June 30, 2005.

(13) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on January 4, 2006.

(14) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 28, 2005.

(15) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on March 30, 2005.

(16) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on May 24, 2005.

(17) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 11, 2005.

(18) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 3, 2005.

(19) Incorporated herein by reference to NRG Energy, Inc. s Form 8-A filed on January 27, 2006.

(20) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on February 6, 2006.

(21) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on February 8, 2006.

(22) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on March 16, 2006.

(23) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on May 3, 2006.

(24) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on May 4, 2006.

(25) Incorporated herein by reference to NRG Energy, Inc. s annual report on Form 10-K filed on March 7, 2006.

(26) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on August 4, 2006.

(27) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on August 10, 2006.

(28) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on November 14, 2006.

(29) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on November 27, 2006.

(30) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on December 26, 2007.

(31) Incorporated herein by reference to NRG Energy, Inc. s quarterly report on Form 10-Q filed on May 2, 2007.

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

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

(34) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on September 4, 2007.