NRG ENERGY, INC.
Form 10-K
February 12, 2009

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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, 2008.

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

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

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

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

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 Rule 12b-2 of the Exchange Act. (Check one):

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

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 $10,001,849,139 based on the closing sale price of $42.90 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 9, 2009**
Common Stock, par value $0.01 per share	236,232,031

Documents Incorporated by Reference:

Portions of the Proxy Statement for the 2009 Annual Meeting of Stockholders

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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:

AB32	Assembly Bill 32 California Global Warming Solutions Act of 2006
ABWR	Advanced Boiling Water Reactor
Acquisition	February 2, 2006 acquisition of Texas Genco LLC, now referred to as the Company s Texas region
APB	Accounting Principles Board
APB 18	APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*
APB 23	APB Opinion No. 23, *Accounting for Income Taxes-Special Areas*
ARO	Asset Retirement Obligation
Baseload capacity	Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
BP	BP Wind Energy North America Inc.
BTA	Best Technology Available
BTU	British Thermal Unit
CAA	Clean Air Act
CAGR	Compound annual growth rate
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
Capital Allocation Plan	Share repurchase program
Capital Allocation Program	NRG s plan of allocating capital between debt reduction, reinvestment in the business, and share repurchases through the Capital Allocation Plan.
CDWR	California Department of Water Resources

CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CL&P	The Connecticut Light & Power Company
CO_2	Carbon dioxide
COLA	Combined Construction and Operating License Application
CPUC	California Public Utilities Commission
CS	Credit Suisse Group
CSF I	NRG Common Stock Finance I LLC
CSF II	NRG Common Stock Finance II LLC

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DNREC	Delaware Department of Natural Resources and Environmental Control
DPUC	Department of Public Utility Control
EAF	Annual Equivalent Availability Factor, which 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
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*
EITF 04-6	EITF Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*
EITF 07-5	EITF No. 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock*
EITF 08-5	EITF 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement*
EITF 08-6	EITF 08-6, *Equity Method Investment Accounting Considerations*
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
ESPP	Employee Stock Purchase Plan
EWG	Exempt Wholesale Generator
Exchange Act	The Securities Exchange Act of 1934, as amended
Expected Baseload Generation	The net baseload generation 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*

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FIN 46R	FIN No. 46(R), *Consolidation of Variable Interest Entities*
FIN 47	FIN No. 47, *Accounting for Conditional Asset Retirement Obligations*
FIN 48	FIN No. 48, *Accounting for Uncertainty in Income Taxes*
FPA	Federal Power Act
Fresh Start	Reporting requirements as defined by SOP 90-7
FSP	FASB Staff Position
FSP APB 14-1	FSP No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*
FSP FIN 39-1	FSP No. FIN 39-1, *Amendment of Financial Interpretation No. 39*
FSP FAS 132R-1	FSP No. FAS 132(R)-1 *Employers Disclosures about Postretirement Benefit Plan Assets*
FSP FAS 133-1 and FIN 45-4	FSP No. FAS 133-1 and FIN No. 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and Financial Interpretation Number 45; and Clarification of the Effective Date of FASB Statement No. 161*
FSP FAS 140-4 and FIN 46(R)-8	FSP No. FAS 140-4 and FIN 46(R)-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial assets and Interests in Variable Interest Entities*
FSP FAS 142-3	FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Asset*
FSP FAS 157-3	FSP No. FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*
GHG	Greenhouse Gases
Gross Generation	The total amount of electric energy produced by generating units and measured at the generating terminal in kWh s or MWh s
Heat Rate	A measure of thermal efficiency computed by dividing the total BTU content of the fuel burned by the resulting kWh s generated. Heat rates can be expressed as either gross or net heat rates, depending whether the electricity output measured is gross or net generation and is generally expressed as BTU per net kWh
Hedge Reset	Net settlement of long-term power contracts and gas swaps by negotiating prices to current market completed in November 2006

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.
kV	Kilovolts

kW	Kilowatts
kWh	Kilowatt-hours
LFRM	Locational Forward Reserve Market
LIBOR	London Inter-Bank Offer Rate
LMP	Locational Marginal Prices
LTIP	Long-Term Incentive Plan
MADEP	Massachusetts Department of Environmental Protection
MACT	Maximum Achievable Control Technology
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
MOU	Memorandum of Understanding
MRTU	Market Redesign and Technology Upgrade
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
MWt	Megawatts Thermal
NAAQS	National Ambient Air Quality Standards
NEPOOL	New England Power Pool
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, 2008
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.

Net Exposure	Counterparty credit exposure to NRG, net of collateral
Net Generation	The net amount of electricity produced, expressed in kWh s or MWh s, that is the total amount of electricity generated (gross) minus the amount of electricity used during generation.
New York Rest of State	New York State excluding New York City
NINA	Nuclear Innovation North America LLC
NO_x	Nitrogen oxide
NOL	Net Operating Loss
NOV	Notice of Violation
NPNS	Normal Purchase Normal Sale

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NRC	United States Nuclear Regulatory Commission
NSR	New Source Review
NYISO	New York Independent System Operator
NYSDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
OTC	Ozone Transport Commission
Padoma	Padoma Wind Power LLC
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 northeastern Wyoming and southeastern Montana, which has low sulfur content
PPA	Power Purchase Agreement
PPM	Parts per Million
PSD	Prevention of Significant Deterioration
PUCT	Public Utility Commission of Texas
PUHCA of 2005	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
Revolving Credit Facility	NRG s $1 billion senior secured credit facility which matures on February 2, 2011
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROIC	Return on invested capital
RPM	Reliability Pricing Model term for capacity market in PJM market
RTO	Regional Transmission Organization, also referred to as an Independent System Operators, or 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
Securities Act	The Securities Act of 1933, as amended
Senior Credit Facility	NRG s senior secured facility, which is comprised of a Term Loan Facility and a $1.3 billion Synthetic Letter of Credit Facility which matures on February 1, 2013, and a $1 billion Revolving Credit Facility, which matures on February 2, 2011.
Senior Notes	The Company s $4.7 billion outstanding unsecured senior notes consisting of $1.2 billion of 7.25% senior notes due 2014, $2.4 billion of 7.375% senior notes due 2016 and $1.1 billion of 7.375% senior notes due 2017
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 106	SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*
SFAS 109	SFAS No. 109, *Accounting for Income Taxes*
SFAS 123R	SFAS No. 123 (revised 2004), *Share-Based Payment*
SFAS 133	SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended*
SFAS 141	SFAS No. 141, *Business Combinations*
SFAS 141R	SFAS No. 141 (revised 2007), *Business Combinations*
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)*
SFAS 159	SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115*
SFAS 160	SFAS No. 160, *Noncontrolling Interest in Consolidated Financial Statements*

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SFAS 161	SFAS No. 161, *Disclosure about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*
Sherbino	Sherbino I Wind Farm LLC
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
Synthetic Letter of Credit Facility	NRG s $1.3 billion senior secured synthetic letter of credit facility which matures on February 1, 2013
TCEQ	Texas Commission on Environmental Quality
Term Loan Facility	A senior first priority secured term loan which matures on February 1, 2013, and is included as part of NRG s Senior Credit Facility.
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
Tosli	Tosli Acquisition B.V.
Uprate	A sustainable increase in the electrical rating of a generating facility
US	United States of America
USEPA	United States Environmental Protection Agency
US GAAP	Accounting principles generally accepted in the United States
VAR	Value at Risk
WCP	WCP (Generation) Holdings, Inc.

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 regional markets in the US and select international markets where its generating assets are located.

As of December 31, 2008, NRG had a total global portfolio of 189 active operating fossil fuel and nuclear generation units, at 48 power generation plants, with an aggregate generation capacity of approximately 24,005 MW, and approximately 550 MW under construction which includes partners interests of 275 MW. In addition, NRG has ownership interests in two wind farms representing an aggregate generation capacity of 270 MW, which includes partner interests of 75 MW. Within the US, NRG has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,925 MW of fossil fuel and nuclear generation capacity in 177 active generating units at 43 plants and ownership interests in two wind farms representing 195 MW of wind generation capacity. These power generation facilities are primarily located in Texas (approximately 11,010 MW, including the 195 MW from the two wind farms), the Northeast (approximately 7,020 MW), South Central (approximately 2,845 MW), and West (approximately 2,130 MW) regions of the US, and 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, nuclear and wind facilities, representing approximately 45%, 33%, 16%, 5% and 1% 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 intermittent, 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 Business Strategy

NRG s business strategy is designed to enhance the Company s position as a leading wholesale power generation company in the US. NRG will continue to utilize its asset base as a platform for growth and development and as a source of cash flow generation which can be used for the return of capital to debt and equity holders. The Company s strategy is focused on: (i) top decile operating performance of its existing operating assets and enhanced operating performance of the Company s commercial operations and hedging program; (ii) repowering of power generation assets at existing sites and development of new power generation projects; and (iii) investment in energy-related new businesses and new technologies where such investments create low to no carbon. This strategy is supported by the Company s five major initiatives (*FOR*NRG, *Repowering*NRG, econrg, Future NRG and NRG Global Giving) which are designed to enhance the Company s competitive advantages in these strategic areas and allow the Company to surmount the challenges faced by the power industry in the coming years. This strategy is being implemented by focusing on the following principles:

Operational Performance The Company is focused on increasing value from its existing assets. 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. *FOR*NRG is a companywide effort designed to increase 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, monetize or reduce excess working capital and other assets. The *FOR*NRG accomplishments include both recurring and one-time improvements measured from a prior base year. For plant operations, the program measures cumulative current year benefits using current gross margins multiplied by 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.

In addition to the *FOR*NRG initiative, the Company seeks to maximize profitability and manage cash flow volatility through the Company s commercial operations strategy. The Company 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.

Finally, 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 during business downturns, including a regular return of capital to its shareholders. NRG will continue to focus on maintaining operational and financial controls designed to ensure that the Company s financial position remains strong.

Development 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. *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 capacity that is expected to be supported by long-term hedging programs, including Power Purchase Agreements, or PPAs, 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.

New Businesses and New Technology NRG is focused on the development and investment in energy-related new businesses and new technologies where the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company, including low or no GHG emitting energy generating sources, such as nuclear, wind, solar thermal, photovoltaic, clean coal and gas, and the employment of post-combustion carbon capture technologies. In 2008, the Company began to increase its focus on ways to invest in or support the development of new energy-related businesses and technologies that could advance its multi-fuel, multi-technology growth strategy and look for new ways to reduce carbon emissions from its overall fleet, and we expect to continue to do so in the future. Furthermore, the Company intends to capitalize on the high growth opportunities presented by government-mandated renewable portfolio standards, tax incentives and loan guaranties for renewable energy projects and new technologies and expected future carbon regulation. A primary focus of this strategy is supported by the **econrg** initiative whereby NRG is 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. econrg represents NRG s commitment to environmentally responsible power generation by addressing the challenges of climate change, clean air and water, and conservation of our natural resources while taking advantage of business opportunities that may inure to NRG as a result of our demonstration and deployment of green technologies. Within NRG, econrg builds upon a 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 the Company s employees.

Company-Wide Initiatives In addition, the Company s overall strategy is also supported by **Future NRG** and **NRG Global Giving** initiatives. 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, training, development, staffing and recruiting needs. Included under the Future NRG umbrella is NRG University, which provides leadership, managerial, supervisory and technical training programs and individual skill development courses. NRG Global Giving is designed to enhance respect for the community, which is one of NRG s core values. Our Global Giving Program invests NRG s resources to strengthen the communities where we do business and seeks to make community investments in four focus areas: community and economic development, education, environment and human welfare.

Finally, 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 US, with approximately 22,925 MW of fossil fuel and nuclear generation capacity in 177 active generating units at 43 plants and ownership interests in two wind farms representing 195 MW of wind generation capacity, as of December 31, 2008. 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 US baseload facilities, which consist of approximately 8,715 MW of generation capacity measured as of December 31, 2008, provide the Company with a significant source of stable cash flow, while its intermediate and peaking facilities, with approximately 14,210 MW of generation capacity as of December 31, 2008, 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. In 2008, NRG completed the construction of the Sherbino (150 MW including partner s interests of 75 MW) and Elbow Creek (120 MW) wind farms which provide electricity to the Company s core region.

The following chart demonstrates the diversification of NRG s domestic power generation assets as of December 31, 2008:

Reliability of future cash flows NRG has hedged a significant portion of its expected baseload generation capacity with decreasing hedged levels through 2014. NRG also has cooperative load contract obligations in South Central region which expire over various dates through 2026. The Company has the capacity and intent to enter into additional hedges when market conditions are favorable. In addition, as of December 31, 2008, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 51% of its expected baseload coal generation output from 2009 to 2014. 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 2008, approximately 91% 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 the Electric Reliability Council of Texas, or ERCOT, to generate power majority 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, which experience from time-to-time and to varying degrees of 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. Also, these facilities are often ideally situated for repowering or the addition of new capacity, because their location and existing infrastructure give them significant advantages over developed sites in their regions that do not have process infrastructure.

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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, 2008 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	$ 2,870	$ 493	$ 318	$ 255	$	$ 90	$ 4,026
Northeast	1,064	415	85			66	1,630
South Central	478	233	10	23		2	746
West	39	125				7	171
International	56	86				16	158
Thermal	12	7	5		114	16	154
Corporate and Eliminations							
Total	$ 4,519	$ 1,359	$ 418	$ 278	$ 114	$ 197	$ 6,885

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, or NERC, 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 The gross heat rate for the Company s fossil-fired power plants represents the average amount of fuel in a BTU required to generate one kWh of electricity divided 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, 2008 and 2007:

	Year Ended December 31, 2008				
Region	Net Owned Capacity (MW)	Net Generation (MWh) (In thousands of MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/kWh	Net Capacity Factor
Texas[a]	11,010	46,937	88.1%	10,300	49.6%
Northeast[b]	7,020	13,349	88.8	10,800	19.9
South Central	2,845	11,148	93.4	10,300	47.6
West	2,130	1,532	91.5%	11,800	10.2%

	Year Ended December 31, 2007				
Region	Net Owned Capacity (MW)	Net Generation (MWh) (In thousands of MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/kWh	Net Capacity Factor
Texas	10,805	47,779	87.6%	10,300	50.7%
Northeast[b]	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%

(a) Net generation (MWh) does not include Sherbino, which is accounted for under the equity method.

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

Employees

As of December 31, 2008, NRG had 3,526 employees, approximately 1,663 of whom were covered by US bargaining agreements. During 2008, the Company did not experience any labor stoppages or labor disputes at any of its facilities.

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Generation Asset Overview

NRG has a significant power generation presence in major competitive power markets of the US 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, 2008.

As of December 31, 2008, the Company s power generation assets consisted of approximately 10,495 MW of gas-fired; 7,540 MW of coal-fired; 3,715 MW of oil-fired; 1,175 MW of nuclear; and 195 MW of wind generating capacity in the US. In addition, NRG also owns approximately 115 MW of thermal capacity domestically as well as 1,080 MW of power generation capacity overseas. The Company s US power generation portfolio by dispatch level is comprised of approximately 38% baseload, 36% intermediate, 25% peaking and 1% intermittent units.

The following is a discussion of NRG s generation assets by segment for the year ended December 31, 2008.

Texas Region As of December 31, 2008, NRG s generation assets in the Texas region consisted of approximately 5,340 MW of baseload generation assets, approximately 195 MW of intermittent wind generation assets, excluding partner interests of 75 MW, in addition to approximately 5,475 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 use lignite and coal, and an undivided 44% interest in two nuclear generating units at South Texas Project, or STP. In 2008, NRG announced the completion of the construction of two wind farms, Sherbino Wind Farm and Elbow Creek Wind Farm, which are also located in the ERCOT market. Power plants are generally dispatched in order of lowest operating cost and as of May 2008 approximately 64% of the net generation capacity in the ERCOT market was natural gas-fired. In the current natural gas price environment, NRG s three solid fuel baseload facilities and two wind farms have significantly lower operating costs than gas plants. NRG expects these three solid-fuel facilities to operate the majority of the time when available, subject to planned and forced outages.

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Northeast Region As of December 31, 2008, NRG generation assets in the Northeast region of the US consisted of approximately 7,020 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 575 MW of southwest Connecticut generation capacity. As of December 31, 2008, NRG s generation assets in the Northeast region consisted of approximately 1,870 MW of baseload generation assets and approximately 5,150 MW of intermediate and peaking assets.

South Central Region As of December 31, 2008, NRG generation assets in the South Central region of the US consisted of approximately 2,845 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 Louisiana consist of its primary asset, Big Cajun II, a coal-fired plant located near Baton Rouge, Louisiana which has approximately 1,490 MW of baseload capacity and 905 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 2026. From time to time, the Company may contract for intermediate generation capacity to support its load obligations. In addition, the region also operates 450 MW of peaking generation in Rockford, Illinois under the PJM region.

West Region As of December 31, 2008, NRG generation assets in the West region of the US consisted of approximately 2,130 MW of generation capacity, primarily located in the California Independent System Operator, or CAISO, control area. The Company s generation assets in the West region are predominately intermediate and peaking duty natural gas-fired plants located in southern California. In addition, the region owns 50% interest in a 90 MW baseload, gas-fired plant located in Nevada.

International Region As of December 31, 2008, NRG had net ownership in approximately 1,080 MW of power generating capacity in Australia and Germany. In addition to traditional power generation facilities, NRG also owns equity interests in certain coal mines in Germany.

Thermal NRG owns thermal and chilled water businesses that generate approximately 1,020 MW thermal equivalents. In addition, NRG s thermal segment owns certain power plants with approximately 115 MW of power generating capacity located in Delaware and 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 PPAs 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, NRG uses hedging strategies which may include power and natural gas forward sales contracts to manage the commodity price risk primarily associated with the Company s base load generation assets. The objective of these hedging strategies is to stabilize the cash flow generated by NRG s portfolio of assets.

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The following table summarizes NRG s US baseload capacity and the corresponding revenues and average natural gas prices resulting from baseload hedge agreements extending beyond December 31, 2008 and through 2014:

	2009	2010	2011	2012	2013	2014	Annual Average for 2009-2014
	(Dollars in millions unless otherwise stated)						
Net Baseload Capacity (MW)	8,701	8,539	8,459	8,432	8,432	8,432	8,499
Forecasted Baseload Capacity (MW)	7,497	7,229	7,164	7,232	7,324	7,395	7,307
Total Baseload Sales (MW)[(a)]	7,156	5,686	4,825	3,272	1,988	789	3,953
Percentage Baseload Capacity Sold Forward[(b)]	95%	79%	67%	45%	27%	11%	54%
Total Forward Hedged Revenues[(c)(d)]	$ 3,851	$ 2,905	$ 2,200	$ 1,670	$ 958	$ 368	$ 1,992
Weighted Average Hedged Price ($ per MWh)[(c)]	$ 61	$ 58	$ 52	$ 58	$ 55	$ 53	$ 58
Weighted Average Hedged Price ($ per MWh) excluding South Central region[(d)]	$ 65	$ 62	$ 54	$ 65	$ 66	$	$ 62
Average Equivalent Natural Gas Price ($ per MMBtu)	$ 8.06	$ 7.92	$ 7.09	$ 7.85	$ 7.43	$ 7.24	$ 7.72
Average Equivalent Natural Gas Price ($ per MMBtu) excluding South Central region	$ 8.37	$ 8.16	$ 7.27	$ 8.60	$ 8.86	$	$ 8.13

(a) Includes amounts under power sales contracts and natural gas hedges. The forward natural gas quantities are reflected in equivalent MWh based on forward market implied heat rate as of December 31, 2008 and then combined with power sales to arrive at equivalent MWh hedged which is then divided by 8,760 hours (8,784 hours in 2012) 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 energy revenue and demand charge.

(d) The South Central region s weighted average hedged prices ranges from $43/MWh $53/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.

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. The preceding factors 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, 2008, NRG had purchased forward contracts to provide fuel for approximately 51% of the Company s requirements from 2009 through 2014. 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/barge transportation agreements and rail car lease arrangements. The Company purchased approximately 35 million tons of coal in 2008, of which 94% is Power River Basin coal and lignite. The Company is one of the largest coal purchasers in the US.

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The following table shows the percentage of the Company s coal and lignite requirements from 2009 through 2014 that have been purchased forward:

	Percentage of Company s Requirement[(a)]
2009	104%
2010	69%
2011	55%
2012	47%
2013	18%
2014	12%

(a) 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, 2008, NRG had approximately 6,349 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 up to the next ten years.

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 for 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 thereafter. 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 October, when demand for electricity is at its 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 delivered fuel prices have tended to drive seasonal electricity prices. The preceding factors 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 environmental capital expenditures and all major capital expenditure projects initiatives, the Company organized its project execution process into one centralized group consisting of Engineering, Procurement and Construction, or EPC. This group combines regional engineering functions with development project engineering, project management, procurement and construction functions to provide a consistent approach to the major capital projects. 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 achieves 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.

FORNRG Update

In 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 to 2008. Improvements in reliability throughout the baseload fleet were the drivers of the year-to-date program performance. In 2008, the Company achieved $259 million of implemented *FOR*NRG 1.0 improvements which exceeded the established $250 million goal. The *FOR*NRG 1.0 program was measured from a 2004 baseline, with the exception of the Texas region where benefits were measured using 2005 as the base year.

Beginning in January 2009, the Company transitioned to *FOR*NRG 2.0 to target an incremental 100 basis point improvement to the Company s ROIC by 2012. The initial targets for *FOR*NRG 2.0 were based upon improvements in the Company s ROIC as measured by increased cash flow. The economic goals of *FOR*NRG 2.0 will focus on: (i) revenue enhancement, (ii) cost savings, and (iii) asset optimization, including reducing excess working capital and other assets. The *FOR*NRG 2.0 program will measure its progress towards the *FOR*NRG 2.0 goals by using the Company s 2008 financial results as a baseline, while plant performance calculations will be based upon the average full-year plant key performance indicators for years the 2006-2008.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2009 through 2013 to meet NRG s environmental commitments will be approximately $1.2 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with federal and state air quality rules and consent orders, 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. While this estimate reflects schedules and controls to meet anticipated reduction requirements, the full impact on the scope and timing of environmental retrofits cannot be determined until issuance of final rules by the United States Environmental Protection Agency, or USEPA.

The following table summarizes the estimated environmental capital expenditures for the referenced periods by region:

	Texas	Northeast	South Central	Total
		(In millions)		
2009	$	$ 256	$	$ 256
2010	8	213	57	278
2011	17	175	116	308

2012	29	67	114	210
2013	21	3	74	98
Total	$ 75	$ 714	$ 361	$ 1,150

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.

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Carbon Update

There is a marked shift towards federal action to address climate change under the Obama administration, which has made clear its intention to make climate change policy a priority for the US through legislation, regulation, and global leadership. President Obama reiterated this commitment in his inaugural address. Congressman Waxman, who sees aggressive action on climate change as a major priority, was elected chair of the House Energy and Commerce Committee and announced that a climate change bill would be delivered out of committee before Memorial Day.

The fossil-fuel based electric generators contribute to GHG emissions. In 2008, in the course of producing approximately 80 million MWh of electricity, NRG s power plants emitted approximately 68 million tonnes of CO_2 of which approximately 61 million tonnes were emitted in the US, approximately 4 million tonnes in Germany, and approximately 3 million tonnes in Australia.

The Company has a multifold strategy with respect to climate change and related GHG regulation. First, the Company is seeking to shape 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 effectively support the development, demonstration and deployment of low and no CO_2 power generation technologies, and that it sets out a transitional allocation approach that buffers initial net compliance costs while transitioning to a full auction. The Company is carrying out its efforts to influence public policy on its own and as part of various collective efforts. For example in January 2009, NRG joined with other members of the United States Climate Action Partnership, or USCAP, to issue the Blueprint for Legislative Action, a detailed framework for legislation to slow, stop and reverse the growth of GHG emissions to achieve an 80% reduction from 2005 levels by 2050.

Second, the Company is actively pursuing investments in new generating facilities and technologies that will be highly efficient and will employ technologies to minimize CO_2 emissions and other air emissions through its *Repowering*NRG program. The Company anticipates that these investments will result in significant 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 STP units 3 and 4 nuclear project in Texas. NRG has formed Nuclear Innovation North America, or NINA, a joint venture with the Toshiba American Nuclear Energy Corporation, to facilitate the development of STP 3 and 4 as well as additional nuclear projects. Further, in 2008, NRG s subsidiary, Padoma Wind Power, LLC, or Padoma, brought 270 MW of wind generating capacity on-line in west Texas at two facilities: (i) the 150 MW Sherbino I Wind Farm LLC, or Sherbino, a 50/50 joint venture with a subsidiary of BP Alternative Energy North America Inc., or BP, and (ii) the wholly-owned, 120 MW Elbow Creek Wind Power LLC facility. The Company is actively developing low and no GHG emitting wind, solar, biomass and natural gas projects. The extent to which these projects, and the remaining coal projects under development, impact the Company s overall climate change exposure will depend on the Company s 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 climate change risk associated with our development projects is 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 CO_2 capture technologies. NRG is exploring a variety of technologies, including one or more scaled up demonstrations at a Company facility in Texas. The captured CO_2 would be sequestered through use for enhanced oil recovery or otherwise in suitable geological formations.

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, including managing a portfolio of GHG offsets and CO_2 allowances. For example, the Company is a member of the Chicago Climate Exchange, a CO_2 emissions reduction, registry and trading system, and has been active in both RGGI auctions to date.

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 climate change 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.

Nuclear Innovation North America

In March 2008, NRG formed NINA, an NRG subsidiary focused on marketing, siting, developing, financing and investing in new advanced design nuclear projects in select markets across North America, including the planned STP units 3 and 4 that NRG is developing on a 50/50 basis with City of San Antonio s agent City Public Service Board of San Antonio, or CPS Energy, at the STP nuclear power station site. NRG s rights to develop STP units 3 and 4 have been contributed to special purpose subsidiaries of NINA. NINA will focus only on the development of new projects and will not be involved in the operations of the existing STP units 1 and 2.

Toshiba American Nuclear Energy Corporation, or TANE, a wholly owned subsidiary of Toshiba Corporation, will serve as the prime contractor on NINA s projects and is a minority shareholder with NRG in the NINA venture. TANE is currently prime contractor of the STP units 3 and 4 project and is providing licensing support and leading all engineering and scheduling activities, which ultimately will lead to responsibility for constructing the project. TANE received a 12% equity ownership in NINA in exchange for $300 million invested in NINA in six annual installments of $50 million, the first of which was received in 2008 and the last three of which are subject to certain conditions. Half of this investment will be to fund development activities related to STP units 3 and 4. The other half will be targeted towards developing and deploying additional Advanced Boiling Water Reactor, or ABWR, projects in North America with other potential partners. TANE is also extending pre-negotiated EPC terms to NINA for two additional two-unit nuclear projects similar to the terms being offered for the STP unit 3 and 4 development.

NINA intends to use the Nuclear Regulatory Commission, or NRC, certified ABWR design, with only a limited number of changes to enhance safety and construction schedules. On November 30, 2007, the 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. On September 30, 2008, NINA filed a revision to the COLA to list Toshiba as the primary vendor. NINA received the combined license review schedule from the NRC on February 11, 2009. Issuing the schedule marks the continuation of NRC s review of the STP expansion application as amended on September 2008. The Company expects to achieve commercial operation for Unit 3 in 2015 and commercial operation for Unit 4 approximately 12 months thereafter. The total rated capacity of the new units, STP units 3 and 4, is expected to equal or exceed 2,700 MW.

In October 2007, NRG and the City of San Antonio, acting through CPS Energy, entered into an interim 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.

***Repowering*NRG Update**

NRG has 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 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.

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.

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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 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.

Currently, NRG has various projects in certain stages of development that includes a new biomass project at Montville Generating Station and the repowering of Big Cajun I and El Segundo sites. As a result of permitting delays related to the on-going Natural Resource Defense Council claims, the El Segundo project is unlikely to reach its original completion date of June 1, 2011.

The following is a summary of repowering projects that have either been completed or are under construction. 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

Cos Cob On June 26, 2008, NRG announced the completion of the repowering of its Cos Cob generating station in Fairfield County, Connecticut which added 40 MW of power to the site. The Company funded and developed this project which added two new gas turbine units, between the existing three units, bringing total site output to 100 MW. All five units were retrofitted to use water injection technology for NOx, resulting in a 50% net station reduction in NO_x. The site also converted to burn ultra-low sulfur distillated oil resulting in a 97% reduction in SO_2 emissions.

Sherbino Wind Farm On October 22, 2008, NRG and its 50/50 joint venture partner, BP, announced the completion of its Sherbino project in Pecos County, Texas. The wind farm was developed by NRG s subsidiary Padoma together with BP. Padoma managed the construction, which began in late 2007. BP will operate and dispatch the facility. Sherbino is a 150 MW wind farm consisting of 50 Vestas wind turbine generators, each capable of generating up to 3 MW of power. Since NRG has a 50 percent ownership, Sherbino will provide the Company a net capacity of 75 MW.

Elbow Creek Wind Farm On December 29, 2008, NRG, through Padoma, announced the completion of its Elbow Creek project, a wholly-owned 120 MW wind farm in Howard County near Big Spring, Texas. The Company funded and developed this wind farm which consists of 53 Siemens wind turbine generators, each capable of generating up to 2.3 MW of power.

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 Optim Energy, LLC, formally 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. 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. NRG provides construction management services and will also provide various ongoing services related to plant operations and maintenance, and use of existing NRG facilities in return for a fixed fee plus reimbursement of the Company s costs. NRG will also provide plant operations and maintenance services and access to certain existing infrastructure at the site on a cost reimbursement basis plus a fixed fee. The construction of the project is on schedule and the plant is expected to begin commercial operations in mid-2009.

GenConn Energy LLC In a procurement process conducted by the Department of Public Utility Control, or DPUC, and finalized in 2008, GenConn Energy LLC, or GenConn, a 50/50 joint venture of NRG and The United Illuminating Company, secured contracts in 2008 with Connecticut Light & Power, or CL&P, for the construction and operation of two 200 MW peaking facilities, at NRG s Devon and Middletown sites in Connecticut. The contracts, which are structured as contracts for differences for the full output of the new power plants, have a 30-year term and call for commercial operation of the Devon project by June 1, 2010 and the Middletown project by June 1, 2011. GenConn has secured all state permits required for the projects and has entered into contracts for engineering and for the procurement of the 8 GE LM6000 combustion turbines required for the projects. GenConn expects to close on financing for the projects in the first half of 2009.

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, or Texas Genco.

Operating Strategy

The Company s business in Texas is comprised of four sets of assets: a nuclear plant, solid-fuel baseload plants, gas-fired plants located in and around Houston, and wind farms. 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 or 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 specific to 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		
	2008	2007	2006
	(In thousands of MWh)		
Coal	32,825	32,648	31,371

Gas	4,647	5,407	7,983
Nuclear[a]	9,456	9,724	9,385
Wind	9		
Total	46,937	47,779	48,739

(a) MWh information reflects the undivided interest in total MWh generated by STP.

Generation Facilities

As of December 31, 2008, NRG s generation facilities in Texas consisted of approximately 11,010 MW of generation capacity. The following table describes NRG s electric power generation plants and generation capacity as of December 31, 2008:

Plant	Location	% Owned	Net Generation Capacity (MW)[c]	Primary Fuel-type
Solid Fuel Baseload Units:				
W. A. Parish[a]	Thompsons, TX	100.0	2,475	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			5,340	
Intermittent Units:				
Elbow Creek	Howard County, TX	100.0	120	Wind
Sherbino	Pecos County, TX	50.0	75	Wind
Total Intermittent Baseload			195	
Operating Natural Gas-Fired Units:				
Cedar Bayou	Baytown, TX	100.0	1,495	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			5,475	
Total Operating Capacity			**11,010**	

(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. The 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 US 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 2,475 MW as of December 31, 2008. Two of these units are 645 MW and 650 MW steam units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 570 MW and 610 MW steam units that were placed in commercial service in June 1980 and December 1982, respectively. 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, 2008. 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 subsidiary of Westmoreland Coal Company and the owner of a substantial portion of the remaining lignite reserves. The contract, entered into August 1999, ended on 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 US 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, 2008, STP had a zero percent forced outage rate and a 98% 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 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 historically fastest growing power markets. It represents approximately 85% of the demand for power in Texas and covers the entire 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 2.2%, compared to a compound annual rate of growth of 1.9% in the US for the same period. For 2008, hourly demand ranged from a low of 19,665 MW to a high of 62,190 MW. The ERCOT market has limited interconnections compared to other markets in the US 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 has experienced significant construction of new generation plants, with over 36,000 MW of new generation capacity added to the market since 1999. As of December 31, 2008, installed generation capacity of approximately 83,000 MW existed in the ERCOT market, including 5,000 MW of generation that has suspended operations, or been mothballed . Natural gas-fired generation represents approximately 53,000 MW, or 64%. Approximately 22,400 MW, or 27%, was lower marginal cost generation capacity such as coal, lignite and nuclear plants. NRG s coal and nuclear fuel baseload plants represent approximately 5,340 MW net, or 24%, of the total solid fuel baseload net generation capacity in the ERCOT market. Additionally, NRG commenced commercial operations of the Sherbino Wind Farm and Elbow Creek Wind Farm which represents approximately 195 MW generation capacity for the Company. Both Sherbino and Elbow Creek Wind Farms are located in the physical control areas of the ERCOT market.

The ERCOT market has established a target equilibrium reserve margin level of approximately 12.5%. The reserve margin for 2008 was 14% forecast to increase to 16% for 2009 per ERCOT s latest Capacity Demand and Reserve Report. There are currently plans being considered by the Public Utility Commission of Texas, or 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 the ERCOT administers. Published in August 2008, the 2007 State of the Market Report for the ERCOT Wholesale Electricity Markets from the Independent Market Monitor indicated that natural gas prices were the primary driver of the trends in electricity prices from 2003 to 2007. 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 while the Sherbino and Elbow Creek wind farms are located in the West Zone.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Council. 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. The 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 the ERCOT does not procure power on behalf of its members other than to maintain the reliable operations of the transmission system. The 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 the 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 the 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 now proposed to take effect in December 2010. 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 the 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 US 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		
	2008	**2007**	**2006**
	(In thousands of MWh)		
Coal	11,506	11,527	11,042
Oil	349	1,169	1,217
Gas	1,494	1,467	1,050
Total	13,349	14,163	13,309

NRG s Northeast region assets are located in or near load centers and inside chronic transmission constraints such as New York City, southwestern 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 has benefited from the introduction of capacity market reforms in both the New England Power Pool, or NEPOOL, and PJM. The Locational Forward Reserve Markets, or LFRM, in the NEPOOL, became effective October 1, 2006, and the transition capacity payments were effective December 1, 2006. In all five 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. The LFRM and interim capacity payments serve as a prelude to the full implementation of the Forward Capacity Market, or FCM, which begins June 1, 2010. PJM s Reliability Pricing Model, or RPM, became effective June 1, 2007, and the Company has participated in auctions providing capacity price certainty through May 2012.

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 2008, Middletown, Montville and Norwalk Power (units 1 and 2) were covered by RMR agreements. Unless terminated earlier, these agreements will terminate on June 1, 2010, which coincides with the commencement of the

FCM in NEPOOL.

Generation Facilities

As of December 31, 2008, NRG s generation facilities in the Northeast region consisted of approximately 7,020 MW of generation capacity, including assets located in transmission constrained areas, such as New York City 1,415 MW, and Southwest Connecticut 575 MW.

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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[(a)]	Somerset, MA	100.0	125	Coal
Connecticut Remote Turbines	Four locations in CT	100.0	145	Oil/Natural Gas
Conemaugh	New Florence, PA	3.7	65	Coal
Keystone	Shelocta, PA	3.7	65	Coal
Total Northeast Region			**7,020**	

(a) Somerset had previously entered into an agreement with the Massachusetts Department of Environmental Protection, or MADEP, to retire or repower the remaining coal-fired unit at Somerset by the end of 2009. In connection with a repowering proposal approved by the MADEP, the date for the shut-down of the unit was extended to September 30, 2010.

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 505 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 10 MW and is activated when Consolidated Edison 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 a settlement agreement reached with the New York Department of Environmental Conservation, or NYSDEC, in January 2005, NRG committed to reducing SO_2 emissions from

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Dunkirk and Huntley stations by 86.8% below baseline emissions of 107,144 by 2013 and NO_x emissions by 80.9% below baseline emission of 17,005 by 2012. In order to comply with the NYSDEC settlement agreement, as well as with various federal and state emissions standards, the Company is in the process of installing back-end control facilities at Dunkirk that are anticipated to be completed in the fall 2009.

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. To comply with the January 2005 NYSDEC settlement agreement referenced above, NRG retired Units 65 and 66 effective June 3, 2007, and as of January 2009, has completed Huntley s back-end control facilities.

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 1, 2, 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 and activated carbon injection systems to control mercury. Units 1, 2 and 3 are fueled with 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 the Delaware Department of Natural Resources and Environmental Control, or 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 Independent Systems Operators, or 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.

SOUTH CENTRAL

As of December 31, 2008, NRG owned approximately 2,845 MW of generating capacity in the South Central region of the US. The region lacks a regional transmission organization or ISO and, therefore, remains a bilateral market, which is not able to take advantage of the large scale economic dispatch of an ISO-administered energy market. 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

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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

The South Central region maximizes its strategic position as a significant coal-fired generator in a market that is highly dependent on natural gas for power generation. South Central also has long-term full service contracts with eleven rural cooperatives serving load across Louisiana and makes incremental wholesale energy sales when its coal-fired capacity exceeds the cooperative contract requirements. The South Central region works to expand its customer base within and beyond Louisiana and works within the confines of the Entergy Transmission System to obtain paths for 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		
	2008	2007	2006
	(In thousands of MWh)		
Coal	10,912	10,812	10,968
Gas	236	118	68
Total	11,148	10,930	11,036

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, 2008, 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 and 4	Jarreau, LA	100.0	210	Natural Gas
Big Cajun I Units 1 and 2	Jarreau, LA	100.0	220	Natural Gas/Oil
Rockford I	Rockford, IL	100.0	300	Natural Gas
Rockford II	Rockford, IL	100.0	150	Natural Gas
Sterlington	Sterlington, LA	100.0	175	Natural Gas
Total South Central			**2,845**	

(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. 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-NOx burners and overfire air systems.

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, 2008, 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, Southwestern Electric Power Company and CLECO, which collectively comprised an additional 10% 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 either employs its owned or leased gas-fired assets or 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 and until certain of these load obligations expire, 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 to date successfully prevented the addition of large industrial or municipal loads at below-market 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.

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, as well as the preservation and ultimate realization of the commercial value of the underlying real estate. There are three principal components to this strategy: (1) capturing the value of the portfolio s generation assets through a combination of forward contracts and market sales of capacity, energy, and ancillary services; (2) leveraging existing site control and emission allowances to permit new, more efficient generating units at existing sites; 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 station s Resource Adequacy, or RA, capacity and consequently the RMR contract with the CAISO on the Encina units was terminated effective December 31, 2007. For calendar year 2008, the El Segundo station has entered into a combination of tolling and RA contracts with multiple load-serving entities and power marketers. The RA contacts covered 387 MW of the available 670 MW and the tolls covered 670 MWs during all available months. For calendar year 2009, El Segundo station entered into approximately 548 MWs RA contracts and is placing the capacity in the market through a portfolio of forward contracts. Cabrillo II sold 28 MW of RA capacity for calendar year 2008, 188 MW of RA capacity for calendar year 2009, and for the

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period January 1, 2010 through November 30, 2013, 88 MW. The Cabrillo II RMR agreement was terminated on December 31 2008. Units with RA contracts also sell into energy and ancillary services markets consistent with unit availability.

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, 2008 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 use natural gas. Also located at the Encina Station is a combustion turbine that provides peaking and black-start 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. Low NOx burner modifications and SCR equipment have been installed on all the steam units.

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 gas-fired generating capacity at its Long Beach Generating Station. Generation from Long Beach provides needed support for the summer peak and during transmission contingencies to load serving entities and the California Independent System Operator. This project is backed by a 10-year PPA executed with SCE in November 2006 and effective through July 31, 2017. The new generation consists of refurbished gas turbines with SCR equipment.

Cabrillo II Cabrillo II consists of 12 combustion turbines located on 4 sites throughout San Diego County with an aggregate generating capacity of approximately 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

Except for the Saguaro facility, NRG s generation assets in the West region operate within the balancing authority of CAISO. CAISO s current market allows NRG s CAISO assets to serve multiple load serving entities, or LSEs, and operates a zonal balancing market and congestion clearing mechanism. CAISO also has a locational capacity requirement, which requires LSEs to procure a significant portion of load from defined local reliability areas. All of NRG s CAISO assets are in the Los Angeles or San Diego local reliability areas. It is expected that on April 1, 2009, CAISO s new market, known as Market Redesign and Technology Upgrade, or MRTU, will become operational. MRTU will establish a day-ahead market for energy and ancillary services and will settle prices locationally. NRG s CAISO assets are all peaking and intermediate in nature and are well positioned to capitalize on the higher locational prices that may result from LMPs in location constrained areas and will continue to satisfy local distribution company capacity requirements. Longer term, NRG s California portfolio s locational advantage may be impacted by new transmission, which may affect load pocket procurement requirements. So far, however, the impacts of increasing demand and need for flexible cycling capability combined with delays in the online date of new transmission have muted the impact of this long-term threat.

California s resource mix will be significantly shaped in the years ahead by California s renewable portfolio standard and its greenhouse gas reduction rules promulgated pursuant to Assembly Bill 32 California Global Warming Solutions Act of 2006, or AB32. In particular, the state s renewable portfolio standard is currently targeted at 20% for 2010 and has been set for 33% by 2020 via Executive Order. While the target requires ratification via legislation, the goal has been widely supported and is expected to create greater demand for low emission resources. The intermittent and remote nature of most renewable resources will still leave a strong demand for flexible load pocket resources. NRG s California portfolio may also be impacted by any mechanism, such as cap-and-trade, that places a price on incremental carbon emissions. NRG s expectation is that the emission costs will be reflected in the market price of power and that the net cost to our existing portfolio of intermediate and peaking resources will be manageable.

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 obtaining necessary permits 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, 2008, NRG, through certain foreign subsidiaries, had investments in power generation projects located in Australia and Germany with approximately 1,080 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 concentrate 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, 2008, 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
Total International			**1,080**	

Australia The Gladstone power station is owned by an unincorporated joint venture. As a member of the venture, the Company owns an undivided 37.5% interest in assets of the power station and a 37.5% interest in its output. A wholly owned subsidiary, NRG Gladstone Operating Services, serves as the station s sole operator. Because NRG is neither the majority owner nor the joint venture manager, NRG does not have unilateral control over the operation, maintenance, and management of this asset. Gladstone station s output is fully contracted through 2029 to Boyne Smelter Limited and Stanwell Corporation Limited. Boyne Smelter is owned by a consortium whose members include all the members of the Gladstone joint venture other than NRG. Its business is to refine alumina into aluminum. Stanwell is a state owned corporation that generates power, purchases power from other generators such as Gladstone, trades power in the Australian National Electricity Market, and delivers power to retail customers.

On June 8, 2006, NRG announced the sale of the Company s 37.5% interest in the joint venture and its 100% interest in NRG Gladstone Operating Services to Transfield Services Infrastructure B.V, or Transfield Services, of Australia. On October 9, 2008, Transfield Services terminated the Gladstone sale and purchase agreement at no cost or expense to the parties, other than transaction costs which are immaterial as to NRG, because of its inability to achieve necessary third party consents. Subsequent negotiations over a plan to reorganize the Gladstone project to facilitate NRG s exit stalled due to a precipitous decline in aluminum prices and asset prices in the second half of 2008. With aluminum demand predicted by some to show little or no growth in 2009 and asset prices showing no signs of recovery, NRG s stay in Australia may be extended. Fortunately, the long term off-take agreements will insulate the Gladstone project from the effects of the recession. The Company will aggressively pursue other options to preserve, protect and enhance the value of this investment.

Germany NRG s interests in Germany include a 50% equity interest in Mitteldeutsche Braunkohlengesellschaft mbH, or MIBRAG, which mines approximately 19 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 82% 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 On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V., or Tosli, which held all NRG s 99.2% voting equity interest in a 156 MW hydroelectric power plant through Itiquira Energetica S.A., or ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 consolidated balance sheet. As discussed in Item 15 Note 3, *Discontinued Operations Business Acquisitions and Dispositions*, to the Consolidated Financial Statements, the activities of Tosli and ITISA has 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 1,020 megawatts thermal equivalent, or MWt. As of December 31, 2008, NRG Thermal provided steam heating to approximately 505 customers and chilled water to 100 customers in five cities in the US. 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 15 MW coal-fired cogeneration facility in Dover, Delaware as well as a 12 MW gas-fired project in Harrisburg, Pennsylvania. Approximately 39% 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 the CFTC, FERC, NRC, PUCT and other public utility commissions in certain states where NRG s generating or thermal assets are located. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO markets in which it participates. NRG must also comply with the mandatory reliability requirements imposed by the North American Electric Reliability Corporation, or NERC, and the regional reliability councils in the regions where the Company operates.

The operations of, and wholesale electric sales from, NRG s Texas region are not subject to rate regulation by the 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

The 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. The 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

The 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, the 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. The 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 US generating facilities has either been determined by the 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 the FERC exclusive rate-making jurisdiction over the wholesale sale of electricity and transmission of electricity in interstate commerce. Under the FPA, the 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 the FERC jurisdiction to review certain transactions and numerous other activities of public utilities. NRG s QFs are currently exempt from the FERC s rate regulation under Sections 205 and 206 of the FPA to the extent that sales are made pursuant to a state regulatory authority s implementation of PURPA.

Public utilities under the FPA are required to obtain the 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 US make sales of electricity pursuant to market-based rates authorized by the FERC. 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 the 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

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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 the 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 the FERC any material changes in status that would reflect a departure from the characteristics that the 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 the 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.

On June 30, 2008 and December 31, 2008, NRG filed with the FERC its updated market power analyses for its Northeast and South Central assets, respectively. Such updates are a requirement of the Commission s grant of market-based rate authority. The Company s updates remain pending.

Section 203 of the FPA requires the FERC s prior approval for the transfer of control of assets subject to the FERC s jurisdiction. Section 204 of the FPA gives the FERC jurisdiction over a public utility s issuance of securities or assumption of liabilities. However, the 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 the FERC.

In compliance with Section 215 of the Energy Policy Act of 2005, or EPAct of 2005, the FERC has approved the 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 the 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 the PUHCA of 2005.

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 the 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 the 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 contract 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, 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. See also Item 15 Note 6, *Nuclear Decommissioning Trust Fund,* to the Consolidated Financial Statements for additional discussion.

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 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 the 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 the ERCOT.

Regional Regulatory Developments

In New England, New York, the Mid-Atlantic region, the Midwest and California, the FERC has approved regional transmission organizations, also commonly referred to as ISOs. Most of these ISOs administer a wholesale centralized bid-based spot market in their regions pursuant to tariffs approved by the 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 the 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

The 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 was scheduled to begin in 2008. On May 20, 2008, the ERCOT announced that it would delay the implementation of the Texas Nodal Protocols, and is now targeting a December 2010 implementation.

In May 2008, the ERCOT real-time energy market experienced periods of high prices as a result of limited intervals during which two zonal constraints were simultaneously binding, and this congestion was irresolvable through the dispatch of available resources. In response, the ERCOT enacted revised protocols, effective June 9, 2008, for addressing such zonal congestion, providing the ERCOT with greater authority to manage such congestion through the use of out-of-market mechanisms towards the goal of lowering prices. In addition, on June 17, 2008, the ERCOT enacted revisions to its price cap procedures in order to further dampen the volatility and high prices. Thus, it is unlikely that the circumstances contributing to the price spikes of May 2008 will be repeated.

On July 17, 2008, as part of its determination of Competitive Renewable Energy Zones, or CREZ, the PUCT approved a significant transmission expansion plan to provide for the delivery of approximately 18,500 MW of energy from the western region of Texas, primarily wind generation. The schedule for construction of the transmission upgrades (approximately 2,300 miles of new 345 kV lines and 42 miles of new 138 kV lines) will be determined in subsequent PUCT proceedings. If completed as currently approved, the transmission upgrades and associated wind generation could impact wholesale energy and ancillary service prices in the ERCOT. The PUCT issued its written order on August 15, 2008.

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 FCM as discussed below. NRG s Norwalk Power facility units 1 and 2 continue to be operated pursuant to an RMR agreement that was accepted by the Commission on July 16, 2007 (effective June 19, 2007). On December 4, 2008, Norwalk Power filed a Settlement Agreement resolving the RMR agreement eligibility and rate issues. The Settlement Agreement provides for an Annual Fixed Revenue Requirement of $34 million for 2008 and $32 million for 2009, continuing at a rate of $32 million per year until FCM is implemented on June 1, 2010. The FERC accepted the Settlement Agreement on December 30, 2008. In the FCM auction for delivery year 2010/2011, the Company sought to de-list Norwalk Power s units 1 and 2. ISO-NE declined to accept that de-list bid on the grounds these units were needed for reliability. The FERC has determined that the units should be compensated at their de-list bid of $5.99 per kW-month. The Company did not seek to de-list Norwalk Power s units 1 and 2 in the FCM auction for delivery year 2011/2012.

On December 28, 2006, the Attorneys General of the State of Connecticut and Commonwealth of Massachusetts filed in the US Court of Appeals for the District of Columbia, or 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, the 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.

On October 20, 2008, Northeast Utilities Service Company, or NU, the parent company of CL&P filed an application with the Connecticut Siting Council for the Greater Springfield Reliability component of the New England East-West Solution, or NEEWS, transmission project, four distinct projects that together represent a significant reinforcement of the 345 kV transmission system. If constructed, the NEEWS projects will increase the import capacity into Connecticut by approximately 1,100 MW.

New York On March 7, 2008, the FERC issued an order accepting the NYISO s proposed market reforms to the in-city Installed Capacity, or ICAP, market, with only minor modifications. The NYISO proposal retains the existing ICAP market structure, but imposes 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 imposes a new reference price on pivotal suppliers and requires bids to be submitted at or below the reference price. The new reference price is derived from 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 s proposed reforms became effective March 27, 2008.

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. The NYSRC approved a 2009 IRM of 16.5%, which is an increase of 1.5% from the 2008 requirement and should have a modest positive effect on capacity prices. Additionally, on January 29, 2008, the FERC accepted the NYISO s installed capacity demand curves for 2008/2009, 2009/2010, and 2010/2011. The demand curves are a critical determinant of capacity market prices, and these revised curves will contribute to the continuation of the current depressed prices, all other factors remaining constant.

PJM On December 12, 2008, PJM filed with the FERC a number of proposed revisions to the RPM capacity market design. PJM has proposed to implement many of the more significant changes in the next RPM Base Residual Auction, scheduled for May 2009 for planning year 2012/2013. On February 9, 2009 PJM filed an Offer of Settlement revising its December 12, 2008 filing with respect to the determination of several of the key inputs for the RPM auctions.

West Region

California has transitioned to a market structure where 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. Cabrillo Power II LLC terminated its RMR agreement with CAISO effective December 31, 2008. See also the *Regional Business Description* for a discussion of the contracting activities that have occurred on the units pursuant to the state s RA program.

CAISO has indicated that MRTU is scheduled to commence April 1, 2009. 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. On October 18, 2008, the FERC accepted the CAISO s Interim Capacity Procurement Mechanism, scheduled to go into effect contemporaneously with the implementation of MRTU. This mechanism is not a capacity market, but rather allows the CAISO to acquire generation capacity if LSEs do not satisfy their Resource Adequacy Obligations.

On October 22, 2008, the FERC issued a definitive order regarding the provision of station power in California. The FERC s order reaffirmed the right of generators to engage in monthly netting of their station power needs and, further, clarified that local transmission-owning utilities are preempted from imposing state-based charges on such generators. This order should allow the Company to engage in monthly netting and thus avoid buying power at retail for many of its stations and, further, to avoid the other charges that the local transmission-owning utilities have been imposing. The Company has submitted a station power plan to the California Public Utilities Commission, or CPUC, and expects to realize savings in operation costs as a result of this order.

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 USEPA published the Clean Air Mercury Rule, or CAMR, and the Clean Air Interstate Rule, or CAIR, market-based cap-and-trade programs to reduce mercury, SO_2 and NOx emissions from coal-fired power plants. On February 8, 2008, the US Court of Appeals for the D.C. Circuit vacated the USEPA s rule delisting coal- and oil-fired electric generating units on which CAMR was based. Power plant mercury emissions are now subject to Section 112 of the Clean Air Act, or CAA, which requires installation of maximum achievable control technology, or MACT, to reduce emissions. On October 17, 2008, the USEPA filed a petition with the US Supreme Court to reconsider the vacatur which was immediately followed by a petition to force EPA to issue the MACT standard from environmental groups. Certain states in which NRG operates coal plants, such as the states of Delaware, Massachusetts and New York, adopted state implementation plans in lieu of the CAMR federal implementation plan. These state rules remain unchanged by the Court s ruling and are likely to meet any new standard for MACT requirements at existing generating units.

CAIR applied to 28 eastern states and D.C., and capped both SO_2 and NOx emissions from power plants in two phases. CAIR applies to most of the Company s power plants in the states of New York, Massachusetts, Connecticut, Delaware, Louisiana, Illinois, Pennsylvania, Maryland and Texas. Following a finding to vacate CAIR in its entirety in July 2008, the D.C. Circuit Court reversed its opinion in December 2008 and remanded CAIR to the USEPA without vacatur. As a result, the effective date for the CAIR NOx trading program remains January 1, 2009. NRG s SO_2 and NOx control plans are driven primarily by state requirements and consent orders. NRG s estimate for environmental capital expenditures reflects changes in schedule and design related to the current status of both CAIR and CAMR. The timing and substantive provisions of any ensuing revised or replacement regulations or legislation may alter the composition and/or rate of spending for environmental retrofits at the Company s facilities.

In a ruling on December 22, 2006, the D.C. Circuit overturned portions of the USEPA s Phase I implementation rule for the new 8-hour ozone standard. Specifically, the court ruled that the 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 CAA on volatile organic carbon, or VOC, and NOx 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 Los Angeles, New York City Area and Houston.

The USEPA strengthened the primary and secondary ground level ozone National Ambient Air Quality Standards, or NAAQS, (eight hour average) from 0.08 ppm to 0.075 ppm on March 12, 2008. The USEPA plans to finalize ozone non-attainment regions by March 2010 and states would likely submit plans to come into attainment

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by 2013. The Company is unable to predict with certainty the impact of the states future recommendations on NRG s operations.

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 a Notice of Violation, or 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.

Climate Change 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 US Supreme Court found that CO_2, the most common GHG, could be regulated as a pollutant and that the USEPA, under the CAA, could regulate CO_2 emissions from mobile sources and by extension, stationary sources. The USEPA gathered input from stakeholders in the fall of 2008, but has not taken any action to regulate CO_2 under the CAA. Since power plants, particularly coal-fired plants, are a significant source of GHG emissions both in the US and globally, it is almost certain that GHG legislative or regulatory actions will encompass power plants as well as other GHG emitting stationary sources.

In 2008, 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 US, 4 million tonnes in Germany and 3 million tonnes in Australia. The impact from federal, regional or state regulation of GHGs 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 CO_2 emissions allowances without having to purchase them in an auction or on the open market. Thereafter, under any such legislation or regulation, the impact on NRG would depend on the Company s level of success in developing and deploying low and no carbon technologies such as those being pursued as part of the *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.

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 Second 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. 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 Second Circuit Court of Appeals decision has been challenged in the US Supreme Court. 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 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 US 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 US Nuclear Waste Policy Act of 1982, owners of nuclear plants, including the owners of STP, entered into contracts setting out the obligations of the owners and the US 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

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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. In 2003, the state of Texas enacted legislation allowing a private entity to be licensed to accept low-level radioactive waste for disposal. NRG intends to continue to ship low-level waste material from STP offsite for as long as an alternative disposal site is available. Should existing off-site disposal become unavailable, the low-level waste material will then be stored on-site. STP s on-site storage capacity is expected to be adequate for STP s needs until other off-site facilities become available.

Regional US Environmental Initiatives

Northeast Region

NRG operates electric generating units located in Connecticut, Delaware, Maryland, Massachusetts and New York which are subject to RGGI. These units will have to surrender one allowance for every US ton of CO_2 emitted with true up for 2009-2011 occurring in 2012. Allowances will be partially allocated in the state of Delaware only. In 2008, NRG emitted approximately 12 million tonnes of CO_2 in RGGI states.

West Region

Under AB32, which was enacted in 2007, the state of California will launch a multi sector climate change program which likely will include, among other things, a phased cap-and-trade approach starting in 2012 and an increased use of renewable energy. The AB32 scoping document, adopted by the California Air Resources Board or CARB in December 2008 is consistent with the trading approach of the Western Climate Initiative or WCI, made up of seven states and four Canadian Provinces. NRG does not expect any implementation of cap-and-trade under AB32 in California to 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 CAA from the USEPA seeking information primarily related to physical changes made at the Big Cajun II plant, and subsequently received a 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. NRG has evaluated the original and subsequent claims and believes they have no merit. Nonetheless, NRG has had discussions with the USEPA about resolving the claims and the Company cannot predict with certainty the outcome of this matter.

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 the DNREC stating that it may be a potentially responsible party with respect to a historic captive landfill. On October 1, 2007, NRG signed an agreement with the DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, the DNREC issued findings that 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 are completed, the Company is unable to predict the impact of any required remediation.

On May 29, 2008, the DNREC issued an invitation to NRG s Indian River Operations, Inc. to participate in the development and performance of a Natural Resource Damage Assessment, or NRDA, at the Burton Island Old Ash Landfill. NRG is currently working with the DNREC and other Trustees to close out the property.

Further details regarding the Company s Domestic Site Remediation obligations can be found in Item 15 Note 23, *Environmental 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 US, 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 Under the German National CO_2 Allocation Plan 2008 2012, MIBRAG was granted CO_2 allocations that are less than the needs of its three generating plants. MIBRAG has minimized the impact of the short allocation by coordinated forward selling of electricity and purchase of CO_2 certificates at times when the CO_2 / electricity spread is profitable. Additionally, MIBRAG has 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 passed through to its off-taker of energy under terms of 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, or Exchange Act, 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 SEC.

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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 natural gas-fired power plants that currently have substantially higher variable costs than NRG s coal-fired baseload power plants. This 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 that 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, 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:

changes 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;

electric supply disruptions, including plant outages and transmission disruptions;

changes in power transmission infrastructure;

fuel transportation capacity constraints;

weather conditions;

changes in the demand for power or in patterns of power usage, including the potential development of demand-side management tools and practices;

development of new fuels and new technologies for the production of power;

regulations and actions of the ISOs; and

federal and state power market and environmental regulation and legislation.

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

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

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

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

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

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

the creditworthiness and liquidity and willingness of fuel suppliers/transporters to do business with the Company.

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

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

A substantial portion of the output from NRG s baseload facilities has been sold forward under fixed price power sales contracts through 2014, 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 could deteriorate over time if the rural cooperatives significantly grow their customer base during the remaining terms of these contracts unless the Company is able to amend or renegotiate its contracts with the cooperatives or add generating capacity.

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

The Company typically enters into hedging agreements, including contracts to purchase or sell commodities at future dates and at fixed prices, in order to manage the commodity price risks inherent in its power generation operations. These activities, although intended to mitigate price volatility, expose the Company to other risks. When the Company sells power forward, it gives up the opportunity to sell power at higher prices in the future, which not only may result in lost opportunity costs but also may require the Company to post significant amounts of cash collateral or other credit support to its counterparties. The Company also relies on counterparty performance under its hedging agreements and is exposed to the credit quality of its counterparties under those agreements. 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.

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

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

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

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

NRG generally attempts to balance its fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for in accordance with SFAS 133, *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. All economic hedges may not necessarily qualify for cash flow hedge accounting treatment. As a result, the Company s quarterly and annual results are subject to significant fluctuations caused by changes in market prices.

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

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

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

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

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

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

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

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

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

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

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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 emission 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 it 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.

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

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

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

Future acquisition activities may have adverse effects.

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

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

NRG s business is subject to extensive foreign, and US 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 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 US make sales of electricity in interstate commerce and are public utilities for purposes of the FPA. The 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 the 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 the 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 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 US Nuclear Waste Policy Act of 1982 to accept and dispose of STP s spent nuclear fuel. See also *Environmental Matters US Federal Environmental Initiatives Nuclear Waste* in Item 1 for further discussion. 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 US 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

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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.

Environmental laws and regulations have generally become more stringent over time, and the Company expects this trend to continue. Regulations currently under revision by USEPA, including CAIR, MACT, standards to control Mercury and the 316 (b) rule to mitigate impact by once through cooling, could result in tighter standards or reduced compliance flexibility. While the NRG fleet employs advanced controls and utilizes industry s best practices, new regulations to address tightened National Ambient Air Quality Standards for Ozone and PM 2.5 or new rules to further restrict ash handling at coal-fired power plants could also further restrict plant operations.

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.

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 the EPA is giving consideration to control of CO_2 emissions from power plants via existing sections of the CAA. Since power plants, particularly coal-fired plants, are a significant source of GHG emissions both in the US and globally, it is almost certain that GHG regulatory actions will encompass power plants as well as other GHG emitting stationary sources. In 2008, 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 US, 4 million tonnes in Germany and 3 million tonnes in Australia.

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 CO_2 emissions allowances without having to purchase them in an auction or on the open market.

Of the approximately 61 million tonnes of CO_2 emitted by NRG in the US in 2008, approximately 12 million tonnes were emitted from the Company s generating units in Connecticut, Delaware, Maryland, Massachusetts, and New York that are subject to RGGI starting 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 CO_2 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.

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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, 2008, approximately 66% of NRG s employees at its US 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 US investments do not have.

NRG has investments in power projects in Australia and Germany. 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 occurrences 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 the Financial Accounting Standards Board, or FASB, Accounting Standard Number 142, *Goodwill and Other Intangible Assets*, or SFAS 142, 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.

Exelon Corporation s unsolicited acquisition proposal and tender offer for all the Company s outstanding common stock is disruptive to the Company s management and business and creates uncertainty that may adversely affect our business.

On October 19, 2008, the Company received an unsolicited proposal from Exelon Corporation to acquire all of the outstanding shares of the Company and on November 12, 2008, Exelon announced a tender offer, referred to as the Exelon tender offer, for all of the Company s outstanding common stock. NRG s Board of Directors, after carefully reviewing the proposal, unanimously concluded that the proposal was not in the best interests of the

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stockholders and has recommended that NRG stockholders not tender their shares. On January 30, 2009 Exelon also announced a proposed slate of nine nominees for election to NRG s Board of Directors at the 2009 Annual Meeting of Stockholders, together with a proposal to increase the number of NRG directors from 12 to 19 with two vacancies, referred to as the Exelon proxy contest. The review and consideration of the Exelon tender offer and proxy contest, have been, and may continue to be, a significant distraction for our management and employees and have required, and may continue to require, the expenditure of significant time and resources by the Company. Exelon s tender offer and proxy contest have also created uncertainty for the Company s employees and this uncertainty may adversely affect the Company s ability to retain key employees and to hire new talent. Exelon s tender offer and proxy contest may also create uncertainty for current and potential business partners, which may cause them to terminate, or not to renew or enter into, arrangements with the Company. In addition, if the Exelon nominees are elected to NRG s Board of Directors, the ability of management to work effectively and efficiently with NRG s Board of Directors with respect to the day to day operations and development of the Company may be restricted, and as a result, may harm the Company s business. Furthermore, the Company and its Board of Directors are defendants in three purported stockholder class action complaints relating to the Exelon proposal as more fully described in Part I, Item 3 Legal Proceedings of this Annual Report on Form 10-K. These lawsuits or any future similar or related lawsuits may become time consuming and expensive. These consequences, alone or in combination, may harm the Company s business.

Exelon Corporation s proxy contest, board expansion and director nominations could result in a Change of Control, as that term is used in the Company s Senior Credit Facility and Senior Notes, which may adversely affect our business.

A default under the Company s Senior Credit Facility and a mandatory change in control offer under the Senior Notes may be triggered if the Exelon nominees compose a majority of NRG s Board of Directors at any time. A Change of Control under the Company s Senior Credit Facility and Senior Notes could occur if the two vacancies on NRG s Board of Directors (created only if the Company s shareholders approve Exelon s proposal to the expand NRG s Board of Directors to 19 members) are not filled by directors nominated by the current NRG Board. A Change of Control may also be triggered by other future events where the resulting composition of NRG s Board of Directors consists of a majority of Exelon nominated directors, such as the retirement or death of any non-Exelon nominated Board member. If a Change of Control is triggered under the Senior Credit Facility and Senior Notes this could have a material and significant impact on the Company s business.

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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 of 1933, as amended, or Securities Act, and Section 21E of the Exchange Act. The words believes , projects , anticipates , plans , expects , intends , estimates and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause NRG Energy, Inc. s actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Risks Related to NRG in Item 1A of this report 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, and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;

NRG s ability 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 ISOs 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 and its subsidiaries that are 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 wind projects;

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.

Item 2 *Properties*

Listed below are descriptions of NRG s interests in facilities, operations and/or projects owned as of December 31, 2008. 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, 2008. 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	2,475	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	1,495	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
Elbow Creek Wind Farm, Howard County, Texas	ERCOT	100.0	120	Wind
Sherbino Wind Farm, Pecos County, Texas	ERCOT	50.0	75	Wind
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
Connecticut Jet Power, Connecticut (four sites)	ISO-NE	100.0	145	Oil/Natural Gas
Conemaugh, New Florence, Pennsylvania	PJM	3.7	65	Coal
Keystone, Shelocta, Pennsylvania	PJM	3.7	65	Coal

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Name and Location of Facility	Power Market	% Owned	Net Generation Capacity (MW)	Primary Fuel-type
South Central Region:				
Big Cajun II, New Roads, Louisiana[b]	SERC-Entergy	86.0	1,490	Coal
Bayou Cove, Jennings, Louisiana	SERC-Entergy	100.0	300	Natural Gas
Big Cajun I, Jarreau, Louisiana	SERC-Entergy	100.0	210	Natural Gas
Big Cajun I, Jarreau, Louisiana	SERC-Entergy	100.0	220	Natural Gas/Oil
Rockford I, Illinois	PJM	100.0	300	Natural Gas
Rockford II, Illinois	PJM	100.0	150	Natural Gas
Sterlington, Louisiana	SERC-Entergy	100.0	175	Natural Gas
West Region:				
Encina, Carlsbad, California	CAISO	100.0	965	Natural Gas
El Segundo Power, California	CAISO	100.0	670	Natural Gas
Long Beach, California	CAISO	100.0	260	Natural Gas
San Diego Combustion Turbines, California (three sites)	CAISO	100.0	190	Natural Gas
Saguaro Power Co., Henderson, Nevada	WECC	50.0	45	Natural Gas
International Region:				
Gladstone Power Station, Queensland, Australia	Enertrade/Boyne Smelter	37.5	605	Coal
Schkopau Power Station, Germany	Vattenfall Europe	41.9	400	Lignite
MIBRAG, Germany[c]	Schkopau, Lippendorf & ENVIA	50.0	75	Lignite

(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

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The following table summarizes NRG s thermal facilities as of December 31, 2008:

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: 1,143 MMBtu/hr. (335 MWt) Chilled Water: 40,630 tons (143 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. 210 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: 296 MMBtu/hr. (87 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. and Procter & Gamble Company	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 and various other office space.

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Item 3 *Legal Proceedings*

Exelon Corporation and Exelon Xchange Corporation v. Howard E. Cosgrove et al., Court of Chancery of the State of Delaware, Case No. 4155-VCL *(filed November 11, 2008)* On November 11, 2008, Exelon Corporation, or Exelon, and its wholly-owned subsidiary, Exelon Xchange, filed a complaint against NRG and NRG s Board of Directors. The complaint alleges, among other things, that NRG s Board of Directors failed to give due consideration and to take appropriate action in response to the acquisition proposal announced by Exelon on October 19, 2008, in which Exelon offered to acquire all of the outstanding shares of NRG common stock at an exchange ratio of 0.485 Exelon shares for each NRG common share. The complaint seeks, among other things, declaratory and injunctive relief: (1) declaring that NRG s Board of Directors has breached its fiduciary duties to the NRG stockholders by rejecting and refusing to consider Exelon s acquisition proposal and by failing to exempt the proposed transaction from application of Section 203 of the Delaware General Corporation Law; (2) compelling NRG s Board of Directors to approve Exelon s acquisition proposal for purposes of Section 203 of the Delaware General Corporations Law; (3) declaring that the adoption of any measure that would have the effect of impeding or interfering with Exelon s acquisition proposal constitutes a breach of NRG s Board of Directors fiduciary duties; and (4) enjoining the defendants from adopting any measures that would have the effect of impeding or interfering with Exelon s acquisition proposal. On November 14, 2008, NRG and NRG s Board of Directors filed a motion to dismiss Exelon s complaint on the grounds that it fails to state a claim upon which relief can be granted. On January 28, 2009, NRG and NRG s Board of Directors filed their brief in support of their motion to dismiss.

Louisiana Sheriffs Pension & Relief Fund and City of St. Claire Shores Police & Fire Retirement System, on Behalf of Themselves and All Others Similarly Situated v. David Crane, et al., Court of Chancery of the State of Delaware, Case No. 4193-VCL *(filed November 25, 2008; served December 11, 2008)* The complaint alleges, among other things, that NRG s Board of Directors failed to give due consideration and to take appropriate action in response to the acquisition proposal announced by Exelon on October 19, 2008, in which Exelon offered to acquire all of the outstanding shares of NRG common stock at an exchange ratio of 0.485 Exelon shares for each NRG common share. The complaint seeks, among other things, declaratory and injunctive relief: (1) declaring that the action is a class action and certifying plaintiff as class plaintiff and plaintiff s counsel as class counsel; (2) declaring that NRG s Board of Directors has breached its fiduciary duties to the NRG stockholders by rejecting and refusing to consider Exelon s acquisition proposal; (3) entering a mandatory injunction requiring NRG to exempt Exelon s offer from Section 203 of the Delaware General Corporation Law; and (4) to the extent injunctive relief is not granted, awarding compensatory damages in favor of the Plaintiffs and other members of the class. On December 23, 2008, NRG and NRG s Board of Directors filed a motion to dismiss the complaint on the grounds that it fails to state a claim upon which relief can be granted. On January 28, 2009, NRG and NRG s Board of Directors filed their brief in support of their motion to dismiss.

Evelyn Greenberg, on Behalf of Herself and All Others Similarly Situated v. David Crane, et al., *(filed October 20, 2008);* ***Joel A. Gerber and Raphael Nach & Jaqueline Nach Co-Trustee The Nach Family Trust U/A, Individually and on behalf of All Others Similarly Situated v. NRG Energy, Inc., et al.*** *(filed November 10, 2008)****; Walter H. Stansbury Individually and on behalf of All Others Similarly Situated v. NRG Energy, Inc., et al.,*** *(filed October 24, 2008),* ***Superior Court of New Jersey-Law Division, Mercer County, Docket No. MER-C-137-08*** Plaintiffs filed three separate complaints against NRG and NRG s Board of Directors alleging, among other things, that NRG s Board of Directors breached its fiduciary duties to NRG stockholders by failing to take action regarding the acquisition proposal announced by Exelon on October 19, 2008, in which Exelon offered to acquire all of the outstanding shares of NRG common stock at an exchange ratio of 0.485 Exelon shares for each NRG common share. On January 6, 2009, the three cases were consolidated and transferred to the Law Division of the Mercer County Superior Court. On January 21, 2009, the plaintiffs filed an Amended Consolidated Complaint in which they allege a single count of breach of fiduciary duty against NRG s Board of Directors and seek injunctive relief: (1) declaring that the action is a class action and certifying plaintiffs as class plaintiffs and counsel as class counsel; (2) declaring that defendants breached their fiduciary duties by summarily rejecting the Exelon offer; (3) ordering defendants to negotiate with respect to the Exelon offer or with respect to another transaction to maximize shareholder value; (4) ordering defendants to exempt Exelon s offer from Section 203 of the Delaware General Corporation Law; (5) awarding compensatory damages including interest; (6) awarding plaintiffs costs and fees; and (7) granting other relief the Court deems proper. A response is due on or before February 20, 2009.

***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)* 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 (Generation) Holdings, Inc., or 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 of California. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that the FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, the FERC rejected this complaint, denied rehearing, and the case was appealed to the US Court of Appeals for the Ninth Circuit, or Ninth Circuit, where oral argument was held on December 8, 2004. On December 19, 2006, the Ninth Circuit decided that in the FERC s review of the contracts at issue, the FERC could not rely on the *Mobil-Sierra* standard presumption of just and reasonable rates, where such contracts were not reviewed by the FERC with full knowledge of the then existing market conditions. WCP and others sought review by the US Supreme Court. WCP s appeal was not selected, but instead held by the Supreme Court. In the appeal that was selected by the Supreme Court, on June 26, 2008, the Supreme Court ruled (1) that the *Mobil-Sierra* public interest standard of review applied to contracts made under a seller s market-based rate authority; (2) that the public interest bar required to set aside a contract remains a very high one to overcome; and (3) that the *Mobil-Sierra* presumption of contract reasonableness applies when a contract is formed during a period of market dysfunction unless (a) such market conditions were caused by the illegal actions of one of the parties or (b) the contract negotiations were tainted by fraud or duress. In this related case, the US Supreme Court affirmed the Ninth Circuit s decision, agreeing that the case should be remanded to FERC to clarify FERC s 2003 reasoning regarding its rejection of the original complaint relating to the financial burdens under the contracts at issue and to alleged market manipulation at the time these contracts were formed. As a result, the US Supreme Court then reversed and remanded the WCP CDWR case to the Ninth Circuit for treatment consistent with its June 26, 2008, decision in the related case. On October 20, 2008, the Ninth Circuit asked the parties in the remanded CDWR case, including WCP and the FERC, whether that Court should answer a question the US Supreme Court did not address in its June 26, 2008, decision; whether the *Mobil-Sierra* doctrine applies to a third-party that was not a signatory to any of the wholesale power contracts, including the CDWR contract, at issue in the case. Without answering that reserved question, on December 4, 2008, the Ninth Circuit vacated its prior opinion and remanded the WCP CDWR case back to the FERC for proceedings consistent with the US Supreme Court s June 26, 2008 decision. On December 15, 2008, WCP and the other seller-defendants filed with FERC a Motion of Order Governing Proceedings on Remand. On January 14, 2009, the Public Utilities Commission of the State of California filed an Answer and Cross Motion for an Order Governing Procedures on Remand, and on January 28, 2009, WCP and the other seller-defendants filed their reply.

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 the 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.

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.

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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. On December 18, 2008, NRG filed with the US Bankruptcy Courts for the Southern District of New York a Closing Report and an Application for Final Decree Closing the Chapter 11 Case for NRG Energy, Inc. et al and on December 29, 2008, the court entered the Final Decree. As of December 21, 2008, the reserve held $9,776,880 in cash and 1,282,783 shares of common stock. On December 21, 2008, the Company issued an instruction letter to The Bank of New York Mellon to distribute all remaining cash and stock in the Disputed Claims Reserve to NRG s creditors. On January 12, 2009, The Bank of New York Mellon commenced the distribution of all remaining cash and stock in the Disputed Claim Reserve to the Company s creditors pursuant to NRG s Chapter 11 bankruptcy plan.

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

None.

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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% Convertible Perpetual Preferred Stock, (ii) 3.625% Convertible Perpetual Preferred Stock, and (iii) 5.75% Mandatory Convertible Preferred Stock.

NRG s common stock is listed on the New York Stock Exchange and has been assigned the symbol: NRG. NRG has submitted to the New York Stock Exchange its annual certificate from its Chief Executive Officer certifying that he is not aware of any violation by the Company of New York Stock Exchange corporate governance listing standards. The high and low sales prices, as well as the closing price for the Company s common stock on a per share basis for 2008 and 2007 (after giving retroactive effect to the two-for-one stock split effective May 25, 2007) are set forth below:

Common Stock Price	Fourth Quarter 2008	Third Quarter 2008	Second Quarter 2008	First Quarter 2008	Fourth Quarter 2007	Third Quarter 2007	Second Quarter 2007	First Quarter 2007
High	$ 25.40	$ 43.95	$ 45.78	$ 43.96	$ 47.19	$ 45.08	$ 45.93	$ 37.10
Low	14.39	22.20	38.36	34.56	38.79	34.76	35.98	27.22
Closing	$ 23.33	$ 24.75	$ 42.90	$ 38.99	$ 43.34	$ 42.29	$ 41.57	$ 36.02

NRG had 234,356,717 shares outstanding as of December 31, 2008, and as of February 9, 2009, there were 236,232,031 shares outstanding. As of February 9, 2009, there were approximately 72,000 common stockholders of record.

Dividends

NRG has not declared or paid dividends on its common stock. To the extent NRG declares such a dividend, 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, 2008, were as follows:

Total Number of Shares Purchased as	Dollar Value of

For the Year Ended December 31, 2008	Total Number of Shares Purchased	Average Price Paid per Share	Part of Publicly Announced Plans or Programs	Shares that may be Purchased Under the Plans or Programs
First quarter	1,281,600	$ 42.73	1,281,600	$ 160,008,401
Second quarter				160,008,401
Third quarter	3,410,283	38.06	3,410,283	30,226,541
Fourth quarter				30,226,541
Total for 2008	4,691,883	$ 39.33	4,691,883	$ 30,226,541

In December 2007, the Company initiated its 2008 Capital Allocation Plan, discussed in Item 15 Note 13, *Capital Structure,* with the repurchase of 2,037,700 shares of NRG common stock during that month for approximately $85 million. In February 2008, the Company s Board of Directors authorized an additional $200 million in common share repurchases that would raise the total 2008 Capital Allocation Plan to approximately

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$300 million. In the first quarter 2008, the Company repurchased 1,281,600 shares of NRG common stock for approximately $55 million. In the third quarter 2008, the Company repurchased an additional 3,410,283 of NRG common stock in the open market for approximately $130 million. As of December 31, 2008, NRG had repurchased a total of 6,729,583 shares of NRG common stock at a cost of approximately $270 million as part of its 2008 Capital Allocation Plan. On October 30, 2008, the Company announced its 2009 Capital Allocation Plan to purchase an additional $300 million in common stock. Share repurchase under the Capital Allocation Plans may be made from time to time at market prices as permitted by securities laws and other requirements, are subject to market conditions and other factors, and may be discontinued at any time.

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 (Excluding Securities Reflected in Column (a)**	**(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	6,650,080	$ 25.84	6,798,074(a)
Equity compensation plans not approved by security holders		N/A	
Total	6,650,080	$ 25.84	6,798,074

(a) Consists of NRG Energy, Inc. s Long-Term Incentive Plan, or the LTIP, and NRG Energy, Inc. s Employee Stock Purchase Plan, or the ESPP. 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 6,798,074 and 7,941,758 shares of common stock remaining available for grants of awards under NRG s LTIP as of December 31, 2008 and 2007, respectively. The ESPP was approved by the Company s stockholders on May 14, 2008. There were 500,000 shares reserved from the Company s treasury shares for the ESPP. There were 500,000 shares remaining under the ESPP as of December 31, 2008. In January 2009, 41,706 shares were issued to employees accounts from the treasury stock reserve for the ESPP.

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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, 2008 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	Dec-2008
NRG Energy, Inc.	$ 100.00	$ 160.58	$ 209.89	$ 249.49	$ 386.10	$ 207.84
S&P 500	100.00	111.22	116.68	135.11	142.53	89.80
UTY	$ 100.00	$ 126.23	$ 149.50	$ 179.67	$ 213.76	$ 155.45

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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 as well as the retroactive effect of the two-for-one stock split effective May 25, 2007. For additional information refer to Item 15 Note 3, *Discontinued Operations Business Acquisition and Disposition*, 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.*

	Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(In millions unless otherwise noted)				
Statement of income data:					
Total operating revenues	$ 6,885	$ 5,989	$ 5,585	$ 2,400	$ 2,080
Total operating costs and expenses	5,156	5,060	4,720	2,290	1,848
Income from continuing operations, net	1,016	569	543	68	157
Income from discontinued operations, net	172	17	78	16	29
Net income	1,188	586	621	84	186
Common share data:					
Basic shares outstanding average	235	240	258	169	199
Diluted shares outstanding average	275	288	301	171	201
Shares outstanding end of year	234	237	245	161	174
Per share data:					
Income from continuing operations basic	4.09	2.14	1.90	0.28	0.78
Income from continuing operations diluted	3.66	1.95	1.78	0.28	0.78
Net income basic	4.82	2.21	2.21	0.38	0.93
Net income diluted	4.29	2.01	2.04	0.38	0.93
Book value	26.69	19.48	19.48	11.31	13.14
Business metrics:					
Cash flow from operations	$ 1,434	$ 1,517	$ 408	$ 68	$ 645
Liquidity position	4,124(a)	2,715	2,227	758	1,600
Ratio of earnings to fixed charges	3.62	2.28	2.38	1.57	1.93
Ratio of earnings to fixed charges and preference dividends	3.17	2.02	2.09	1.32	1.92
Return on equity	16.71%	10.65%	10.98%	3.77%	6.91%
Ratio of debt to total capitalization	47.57%	55.70%	57.38%	44.91%	44.57%
Balance sheet data:					
Current assets	$ 8,492	$ 3,562	$ 3,083	$ 2,197	$ 2,119
Current liabilities	6,581	2,277	2,032	1,357	1,090
Property, plant and equipment, net	11,545	11,320	11,546	2,559	2,639
Total assets	24,808	19,274	19,436	7,467	7,906

Long-term debt, including current maturities and capital leases	8,168	8,361	8,726	2,456	3,220
Total stockholders equity	$ 7,109	$ 5,504	$ 5,658	$ 2,231	$ 2,692

N/A Not applicable

(a) Includes Funds deposited by counterparties of $754 as of December 31, 2008, which represents cash held as collateral from hedge counterparties in support of energy risk management activities and for which it is the Company s intention as of December 31, 2008 to limit the use of these funds.

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

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In millions)				
Energy	$ 4,519	$ 4,265	$ 3,155	$ 1,840	$ 1,181
Capacity	1,359	1,196	1,516	563	612
Risk management activities	418	4	124	(292)	61
Contract amortization	278	242	628	9	(6)
Thermal	114	125	124	124	112
Hedge Reset			(129)		
Other	197	157	167	156	120
Total operating revenues	$ 6,885	$ 5,989	$ 5,585	$ 2,400	$ 2,080

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 includes fair value changes of economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges and trading activities. 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 and Texas Genco purchase accounting 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. See also Item 15 Note 5, *Accounting for Derivative Instruments 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, 2008 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 presents the results of the Company s operations for the years ended December 31, 2008, 2007 and 2006. 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 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 regional markets in the United States and select international markets where its generating assets are located.

As of December 31, 2008, NRG had a total global portfolio of 189 active operating fossil fuel and nuclear generation units, at 48 power generation plants, with an aggregate generation capacity of approximately 24,005 MW, and approximately 550 MW under construction which includes partners interests of 275 MW. In addition, NRG has ownership interests in two wind farms representing an aggregate generation capacity of 270 MW, which includes partner interests of 75 MW. Within the US, NRG has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,925 MW of fossil fuel and nuclear generation capacity in 177 active generating units at 43 plants and ownership interests in two wind farms representing 195 MW of wind generation capacity. These power generation facilities are primarily located in Texas (approximately 11,010 MW, including the 195 MW from the two wind farms), the Northeast (approximately 7,020 MW), South Central (approximately 2,845 MW), and West (approximately 2,130 MW) regions of the US, and 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, nuclear and wind facilities, representing approximately 45%, 33%, 16%, 5% and 1% 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 intermittent, 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 Business Strategy

NRG s business strategy is designed to enhance the Company s position as a leading wholesale power generation company in the US. NRG will continue to utilize its asset base as a platform for growth and development and as a source of cash flow generation which can be used for the return of capital to debt and equity holders. The Company s strategy is focused on: (i) top decile operating performance of its existing operating assets and enhanced operating performance of the Company s commercial operations and hedging program; (ii) repowering of power generation assets at existing sites and development of new power generation projects; and (iii) investment in energy-related new businesses and new technologies where such investments create low to no carbon. This strategy is supported by the Company s five major initiatives (*FOR*NRG, *Repowering*NRG, econrg, Future NRG and NRG Global Giving) which are designed to enhance the Company s competitive advantages in these strategic areas and allow the Company to surmount the challenges faced by the power industry in the coming years. This strategy is being implemented by focusing on the following principles:

Operational Performance The Company is focused on increasing value from its existing assets. 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. *FOR*NRG is a companywide effort designed to increase 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, monetize or reduce excess working capital and other assets. The *FOR*NRG accomplishments include both recurring and one-time improvements measured from a prior base year. For plant operations, the program measures cumulative current year benefits using current gross margins multiplied by 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.

In addition to the *FOR*NRG initiative, the Company seeks to maximize profitability and manage cash flow volatility through the Company s commercial operations strategy. The Company 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.

Finally, 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 during business downturns, including a regular return of capital to its shareholders. NRG will continue to focus on maintaining operational and financial controls designed to ensure that the Company s financial position remains strong.

Development 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. *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 capacity that is expected to be supported by long-term hedging programs, including PPAs, 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.

New Businesses and New Technology NRG is focused on the development and investment in energy-related new businesses and new technologies where the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company, including low or no GHG emitting energy generating sources, such as nuclear, wind, solar thermal, photovoltaic, clean coal and gas, and the employment of post-combustion carbon capture technologies. In 2008, the Company began to increase its focus on ways to invest in or support the development of new energy-related businesses and technologies that could advance its multi-fuel, multi-technology growth strategy and look for new ways to reduce carbon emissions from its overall fleet, and we expect to continue to do so in the future. Furthermore, the Company intends to capitalize on the high growth opportunities presented by government-mandated renewable portfolio standards, tax incentives and loan guaranties for renewable energy projects and new technologies and expected future carbon regulation. A primary focus of this strategy is supported by the **econrg** initiative whereby NRG is 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. econrg represents NRG s commitment to environmentally responsible power generation by addressing the challenges of climate change, clean air and water, and conservation of our natural resources while taking advantage of business opportunities that may inure to NRG as a result of our demonstration and deployment of green technologies. Within NRG, econrg builds upon a 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 the Company s employees.

Company-Wide Initiatives In addition, the Company s overall strategy is also supported by **Future NRG** and **NRG Global Giving** initiatives. 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, training, development, staffing and recruiting needs. Included under the Future NRG umbrella is NRG University, which provides leadership, managerial, supervisory and technical training programs and individual skill development courses. NRG Global Giving is designed to enhance respect for the community, which is one of NRG s core values. Our Global Giving Program invests NRG s resources to strengthen the communities where we do business and seeks to make community investments in four focus areas: community and economic development, education, environment and human welfare.

Finally, 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.

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Business Environment

General Industry Trends impacting the power industry include (i) the continued constrained credit and capital markets along with deepening recessionary environment, and (ii) increased regulatory and political scrutiny. The industry dynamics and external influences that will affect the Company and the power generation industry in 2009 and for the medium term include:

Financial Credit Market Availability and Domestic Recession A sharp economic downturn in the US and overseas during 2008 was prompted by a combination of factors: tight credit markets, speculation and fear regarding the health of the US and global financial systems, and weaker economic activity including a global economic recession. Power generation companies are capital intensive and, as such, rely on the credit markets for liquidity and for the financing of power generation investments. In addition, economic recessions historically result in lower power demand, power prices, and fuel prices. NRG has a diversified liquidity program, with $3.4 billion in total liquidity, excluding funds deposited by counterparties, and a first and second lien structure that enables significant strategic hedging while reducing requirements for the posting of cash or letters of credit as collateral. NRG expects to continue to manage commodity price volatility through its strategic hedging program, under which the Company expects to hedge revenues and fuel costs. This program should provide the Company with the flexibility to enter into hedges opportunistically, such as when gas prices are increasing, while at the same time protecting NRG against longer-term volatility in the commodity markets. The Company believes that an economic recession is unlikely to have material impact on the Company s cash generation in the near term due to the hedged position of its portfolio. NRG transacts with a diversified pool of counterparties and actively manages our exposure to any single counterparty. See also Part II, Item 7 Liquidity and Capital Resources, and Part II, Item 7a Quantitative and Qualitative Disclosures about Market Risk for a further discussion.

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.

Climate Change There is a marked shift towards federal action to address climate change under the Obama administration, which has made clear its intention to make climate change policy a priority for the US through legislation, regulation, and global leadership. President Obama reiterated this commitment in his inaugural address. Congressman Waxman, who sees aggressive action on climate change as a major priority, was elected chair of the House Energy and Commerce Committee and announced that a climate change bill would be delivered out of committee before Memorial Day.

Regional efforts have gained momentum as well. The RGGI CO_2 cap-and-trade program for electric generating units went into effect on January 1, 2009. California, the Western Climate Initiative, and the Midwest GHG Accord continue to develop market based programs in their respective jurisdictions.

Since fossil fueled power plants, particularly coal-fired plants, are a significant source of GHG emissions both in the US and globally, it is almost certain that future GHG legislative and regulatory actions will encompass power plants as well as other GHG emitting stationary sources. In 2008, 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 US, 4 million tonnes in Germany, and 3 million tonnes in Australia. NRG emissions subject to RGGI were 12 million tonnes in 2008. 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 degree to which offsets may be used for compliance and their price and availability, 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. 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.

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Infrastructure Development In response to record peak power demand, tightening reserve margins, and volatile natural gas prices experienced in recent years, the power generation industry has added significant capacity for both transmission and generation. In addition to traditional gas-fired capacity, much of the new generation would be from non-fossil fuel sources, including nuclear and renewable sources. 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. During 2007, 18 gigawatts of previously announced pulverized coal generation projects were canceled due to increasing public and political concern regarding carbon emissions limiting the pace of development. During 2008, the credit market crisis severely constrained the industry s ability to finance power projects. Despite the challenges presented by financing availability and carbon legislation constraints, NRG believes the long-term demand for power generation will continue to require new generation.

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

Other Factors

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

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

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

- weather conditions;
- market liquidity;
- capability and reliability of the physical electricity and gas systems;

local transportation systems; and

the nature and extent of electricity deregulation.

Environmental Matters, 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, 2008, 2007 and 2006, 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 Program

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.

On October 30, 2008, the Company announced its 2009 Capital Allocation Plan to purchase an additional $300 million in common stock, subject to restrictions under the US securities laws. As part of the 2009 program, the Company will invest over $511 million in maintenance and environmental capital expenditures in the existing assets in 2009 and $256 million in investment in projects under *Repowering*NRG that are currently under construction or for which there exists current obligations. Finally, in addition to scheduled debt amortization payment, in the first quarter 2009 the Company will offer its first lien lenders $197 million of its 2008 excess cash flow (as defined in the Senior Credit Facility).

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Significant events during the year ended December 31, 2008

Results of Operations and Financial Condition

Mark-to-market gains The Company s risk management activities recognized $414 million in mark-to-market gains driven by lower energy prices due to the downward trend in natural gas prices during the second half 2008. High price volatility in energy related commodities during 2008 drove the extreme volatility reported in NRG interim results of operations and consolidated balance sheets during the second and third quarters of 2008, due to the commodities impact on the fair value of our derivative contracts.

Liquidity Position The Company s total liquidity rose $1.4 billion as the declining natural gas prices increased funds deposited by counterparties by $754 million. Cash balances grew by $362 million since the end of 2007 as $1.4 billion of cash provided by operating activities exceeded cash used for all phases of the Company s Capital Allocation Program, including $899 million of capital expenditures, $185 million in treasury share payments and a $214 million net debt reduction.

Higher energy prices Energy revenues rose 6% as a result of strong operating performance at the power plants which allowed the Company to sell generation at higher energy prices especially in the second quarter 2008.

Higher capacity revenues Capacity revenues rose $163 million as a result of a greater portion of Texas baseload contracts having a capacity component.

Sale of ITISA On April 28, 2008, NRG completed the sale of its interest in a 156 MW hydroelectric power plant to Brookfield Renewable Power Inc. The Company recognized a $164 million after tax gain on the sale and received $300 million of cash proceeds. See Item 15 Note 3, *Discontinued Operations*, *Business Acquisition and Dispositions,* for a further discussion of the activities of ITISA that have been classified as discontinued operations.

Reduced development costs As of January 1, 2008, the company began to capitalize the STP units 3 and 4 costs following the docketing of the COLA which resulted in decline of development costs of $52 million.

Lower other income Interest income decreased by $25 million as the result of lower market interest rates on cash deposits. In addition, the Company recorded an impairment charge of $23 million to restructure distressed investments in commercial paper.

Lower interest expense Interest expense decreased $69 million as the result of the interest savings on the $531 million debt repayments beginning December 2007 accompanied by a reduction of variable interest rates on long-term debt.

Other

NINA In March 2008, NRG formed NINA, an NRG subsidiary focused on marketing, siting, developing, financing and investing in new advanced design nuclear projects in select markets across North America, including the planned STP units 3 and 4 that NRG is developing on a 50/50 basis with CPS Energy. TANE will serve as the prime contractor on all of NINA s projects, and has partnered with NRG on the NINA venture, and received a 12% equity ownership in NINA in exchange for a $300 million investment in NINA in six annual installments of $50 million, the first of which was received during 2008 and the last three of which are subject to certain conditions. On February 12, 2009, the Company announced that NINA completed negotiations for the EPC agreement with TANE to build the STP expansion. Concurrent with the execution of the EPC agreement, NINA will enter into a $500 million credit facility with Toshiba to finance the cost of long-lead materials for STP 3 and 4.

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Unsolicited Exelon Proposal On October 19, 2008, the Company received an unsolicited proposal from Exelon Corporation to acquire all of the outstanding shares of the Company and on November 12, 2008, Exelon announced a tender offer for all of the Company s outstanding common stock. On January 7, 2009, Exelon extended the tender offer to February 25, 2009, and indicated that further extensions may follow. NRG s Board of Directors, after carefully reviewing the proposal, unanimously concluded that the proposal was not in the best interests of the stockholders and has recommended that NRG stockholders not tender their shares. In addition, on January 30, 2009 Exelon announced a proposed slate of nine nominees for election to the NRG Board at the 2009 Annual Meeting of Stockholders, together with a proposal to increase the number of NRG directors from 12 to 19.

Sherbino Wind Farm On October 22, 2008, NRG and its 50/50 joint venture partner, BP, announced the completion of its 150 MW Sherbino wind farm. Since NRG has a 50 percent ownership, Sherbino will provide the Company a net capacity of 75 MW.

Elbow Creek Wind Farm On December 29, 2008, NRG, through Padoma, announced the completion of its Elbow Creek project, a wholly-owned 120 MW wind farm in Howard County near Big Spring, Texas. The Company funded and developed this wind farm which consists of 53 Siemens wind turbine generators, each capable of generating up to 2.3 MW of power.

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Consolidated Results of Operations

2008 compared to 2007

The following table provides selected financial information for NRG Energy, Inc., for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	2007	Change%
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 4,519	$ 4,265	6%
Capacity revenue	1,359	1,196	14
Risk management activities	418	4	N/A
Contract amortization	278	242	15
Thermal revenue	114	125	(9)
Other revenues	197	157	25
Total operating revenues	6,885	5,989	15
Operating Costs and Expenses			
Cost of operations	3,598	3,378	7
Depreciation and amortization	649	658	(1)
General and administrative	319	309	3
Development costs	46	101	(54)
Total operating costs and expenses	4,612	4,446	4
Gain on sale of assets		17	(100)
Operating Income	2,273	1,560	46
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	59	54	9
Gains on sales of equity method investments		1	(100)
Other income, net	17	55	(69)
Refinancing expenses		(35)	(100)
Interest expense	(620)	(689)	(10)
Total other expenses	(544)	(614)	(11)
Income from Continuing Operations before income tax expense	1,729	946	83
Income tax expense	713	377	89

Income from Continuing Operations		1,016		569	79
Income from discontinued operations, net of income tax expense		172		17	N/A
Net Income	$	1,188	$	586	103
Business Metrics					
Average natural gas price Henry Hub ($/MMbtu)		8.85		7.12	24%

N/A Not applicable

Operating Revenues

Operating revenues increased by $896 million for the year ended December 31, 2008, compared to 2007. This was due to:

Energy revenues increased $254 million during the year ended December 31, 2008, compared to the same period in 2007:

- o *Texas* increased $172 million, with $219 million of this increase driven by higher prices, offset by $47 million reduced generation. The price variance was attributable to a more favorable mix of merchant versus contract sales, as well as a 28% increase in merchant prices partially offset by a 14% decrease in contract energy prices. The 839 thousand MWh or 2% reduction in generation was comprised of a 3% reduction from nuclear plant generation, a 14% reduction from gas plant generation, offset by a 1% increase in coal plant generation. The reduction in gas plant generation was attributable to the effects of hurricane Ike in September 2008.

- o *Northeast* decreased $40 million, with $66 million reduced generation offset by a $26 million increase driven by higher energy prices. The decline due to generation was driven by a net 6% reduction in the region s generation, due to a decrease in oil-fired generation as a result of higher average oil prices as well as decrease in gas-fired generation related to a cooler summer in 2008 compared to 2007. The increase due to energy prices reflects an average 6% rise in merchant energy prices offset by lower contract revenue, driven by higher costs required to service the PJM contracts, as a result of the increase in market energy prices.

- o *South Central* increased $74 million, attributable to higher merchant energy revenues. The growth in merchant energy revenues reflected 577 thousand more merchant MWh sold, as a decrease in contract load MWh allowed more sales to the merchant market at higher prices.

- o *West* increased $35 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Capacity revenues increased $163 million during the year ended December 31, 2008, compared to the same period in 2007:

- o *Texas* increased $130 million due to a greater proportion of base-load contracts, which contain a capacity component.

- o *Northeast* increased $13 million reflecting $31 million higher capacity revenues in the PJM and NEPOOL markets offset by a $18 million reduction in capacity revenue in NYISO.

- o *South Central* increased $12 million due to a $10 million higher capacity payment from the region s cooperative customers and an $8 million rise in RPM capacity payments from the PJM market. These increases were offset by a $6 million reduction related to lower contract volume to other customers.

- o *West* increased $3 million due to a tolling arrangement at Long Beach plant offset by the reduction of revenue from the El Segundo tolling arrangement.

Contract amortization revenues increased $36 million during the year ended December 31, 2008, compared to the same period in 2007 due to the volume of contracted energy affected by a greater spread between contract prices and market prices used in the Texas Genco purchase accounting.

Other revenues increased by $40 million during the year ended December 31, 2008, compared to the same period in 2007. The increases arose from greater ancillary services revenue of $28 million and increased activity in the trading of emission allowances and carbon financial instruments of $21 million. These increases were offset by $14 million in lower gas and coal trading activities.

Risk management activities revenues from risk management activities include economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges and trading activities. Such revenues increased by $414 million during the year ended December 31, 2008, compared to the same period in 2007. The breakdown of changes by region was as follows:

	Year Ended December 31, 2008				
	Texas	Northeast	South Central	Thermal	Total
			(In millions)		
Net (losses)/gains on settled positions, or financial revenues	$ (95)	$ 3	$ (16)	$ 1	$ (107)
Mark-to-market results					
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	(25)	(13)			(38)
Reversal of previously recognized unrealized losses/(gains) on settled positions related to trading activity	1	(14)	(19)		(32)
Net unrealized gains on open positions related to economic hedges	400	96		4	500
Net unrealized gains on open positions related to trading activity	37	13	45		95
Subtotal mark-to-market results	413	82	26	4	525
Total derivative gains	$ 318	$ 85	$ 10	$ 5	$ 418

NRG s 2008 gain is comprised of $525 million of mark-to-market gains and $107 million in settled losses, or financial revenue. Of the $525 million of mark-to-market gains, the $38 million loss represents the reversal of mark-to-market gains recognized on economic hedges and the $32 million loss represents the reversal of mark-to-market gains recognized on trading activity. Both of these losses ultimately settled as financial revenues during 2008. The $500 million gain from economic hedge positions included a $524 million increase in value of forward sales of electricity as the result of the reduction in forward power and gas prices at the close of the year-ended December 31, 2008. These hedges are considered effective economic hedges that do not receive cash flow hedge accounting treatment. In addition there was a $24 million loss primarily from hedge accounting ineffectiveness related to gas trades in the Texas region which was driven by decreasing forward gas prices while forward power prices declined at a slower pace. NRG also recognized a $95 million unrealized gain associated with the company s trading activity. This gain was primarily due to declining forward electricity and fuel prices.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues the changes in such results should not be viewed in isolation, but rather should be taken together with the effects of pricing and cost changes on energy revenues. During and throughout 2008, NRG hedged a portion of the Company s 2008 through 2013 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.

Cost of Operations

Cost of operations increased $220 million during the year ended December 31, 2008, compared to the same period in 2007 but it decreased as a percentage of revenues from 56% for the year ended 2007 compared to 52% for the year ended 2008.

Cost of energy increased $213 million during the year ended December 31, 2008, compared to the same period in 2007 and as a percentage of revenue it decreased from 41% for 2007 as compared to 38% for 2008. This increase was due to :

- *Texas* Cost of energy increased $59 million due to a net increase in fuel expense and ancillary service costs offset by reductions in nuclear fuel expenses, purchased power expense and amortization of contracts cost.

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Fuel expense Natural gas costs rose $99 million due to an increase of 28% in average natural gas prices, offset by a 14% decrease in gas-fired generation. In addition, coal costs increased by $44 million a result of higher coal prices and the settlement payment related to a coal contract dispute. These increases were offset by a decrease of $19 million in nuclear fuel expense as amortization of nuclear fuel inventory established under Texas Genco purchase accounting ended in early 2008.

Purchased energy Purchased energy expense decreased $26 million as a result of lower forced outage rates at the region s base-load plants.

Ancillary service expense Ancillary services and other costs increased by $14 million as a result of higher ERCOT ISO fees offset by reduced purchased ancillary services costs.

Fuel contract amortization Amortized contract costs decreased by $59 million due to a $36 million decrease in the amortization of water supply contracts which ended in 2007. In addition, the amortization of coal contracts decreased by a net $22 million as a result of a reduction in expense related to in-the-money coal contract amortization. These contracts were established under Texas Genco purchase accounting.

o *Northeast* Cost of energy increased $54 million due to higher fuel costs. Coal costs increased $61 million due to higher coal prices and fuel transportation surcharges. Natural gas costs rose $22 million as a result of 32% higher average natural gas prices, despite 12% lower generation. These increases were offset by a $27 million reduction in oil costs as a result of 55% lower oil-fired generation.

o *South Central* Cost of energy increased $56 million due to higher fuel costs and increased purchased energy expense.

Fuel expense Coal costs increased $16 million resulting from an increase in coal consumption and higher fuel transportation surcharges; natural gas costs rose by $14 million as the region s peaker plants ran extensively to support transmission system stability after hurricane Gustav.

Purchased energy Higher purchased energy expenses of $16 million reflected higher natural gas costs for tolling contracts.

Transmission costs Increased by $9 million due to additional point-to-point transmission costs driven by an increase in merchant energy sales.

o *West* Cost of energy increased $30 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other operating costs increased $7 million during the year ended December 31, 2008 compared to the same period in 2007. This increase was due to:

o *Texas* increased $30 million due to a second planned outage at STP and the acceleration of planned outages at the base-load plants.

o *Northeast* decreased $3 million due to $18 million lower operating and maintenance expenses resulting from less outage work at the Norwalk plants and Indian River plants. This was offset by a $16 million increase in utilities cost. The 2007 utilities cost included a benefit of $19 million due to a lower than planned settlement of the station service agreement with CL&P.

- *South Central* decreased by $10 million due to reduction in major maintenance expense. The 2007 expense included more extensive outage work that was performed at Big Cajun II plant.

- *West* decreased by $4 million due to a $3 million reduction in lease expenses and an environmental liability of $2 million which was recognized in 2007 related to the El Segundo plant.

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General and Administrative

NRG s G&A costs for the year ended December 31, 2008, increased by $10 million compared to 2007, and as a percentage of revenues was 5% in both 2008 and 2007.

- *Wage and benefit costs* increased $19 million attributable to higher wages and related benefits cost increases.
- *Consultant cost* increased by $3 million resulting from $8 million spent on Exelon s exchange offer offset by a $5 million reduction in information technology consultants.
- *Franchise tax* The Company s Louisiana state franchise tax decreased by approximately $4 million. Prior year franchise tax was assessed based on the Company s total debt and equity that increased significantly following the acquisition of Texas Genco.
- *Insurance cost* decreased by $4 million due to favorable rates.

Development Costs

NRG s development costs for the year ended December 31, 2008 decreased by $55 million compared to 2007. These costs were due to the Company s *Repowering*NRG projects:

- *Texas STP units 3 and 4 projects* No development expense was reflected in results of operations for 2008 as NRG began to capitalize STP units 3 and 4 development costs incurred after January 1, 2008, following the NRC s docketing of the Company s COLA in late 2007. The Company recorded $52 million in development expenses during 2007.
- *Wind projects* The Company incurred $21 million in costs related to wind development which is a $4 million decrease from the same period in 2007.
- *Other projects* The Company incurred $25 million in development costs related to other domestic *Repowering*NRG projects in 2008, which decreased $7 million from the same period in 2007 as a result of the capitalization of costs to develop the El Segundo Energy Center in 2008.

Gain on Sale of Assets

The Company reported no gains on sales of assets for 2008. For 2007, NRG s gain on the sale of assets was $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 $18 million.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates for the year ended December 31, 2008, increased by $5 million compared to 2007. This increase was due to a $9 million mark-to-market unrealized gain on a forward contract for a natural gas swap executed to hedge the future power generation of Sherbino, offset by a $4 million reduction in earnings from international equity investments.

Other Income, Net

NRG s other income, net decreased by $38 million for 2008 compared to the same period in 2007. The Company recorded a further $23 million impairment charge in 2008 to restructure distressed investments in commercial paper, for which an $11 million impairment charge was taken in the fourth quarter of 2007. This 2008 impairment charge, along with cash receipts of $2 million, reduced the carrying value of the commercial paper to $7 million. In addition, the 2008 results reflect reduced interest income of $25 million from lower market interest rates on cash deposits.

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Interest Expense

NRG s interest expense decreased by $69 million for 2008 compared to the same period in 2007. This decrease was due to interest savings on $531 million debt repayments accompanied by a reduction on the variable interest rates on long-term debt. The debt repayments included a $300 million prepayment in December 2007 and an additional payment of $143 million in March 2008 of the Term Loan Facility in connection with the mandatory offer under the Senior Credit Facility. Interest capitalized on *Repowering*NRG projects under construction also contributed to this decrease in interest expense. Offsetting this decrease was the $45 million payment made to the Credit Suisse Group, or CS, for the benefit of NRG Common Stock Finance I LLC, or CSF I, in August 2008 to early settle the embedded derivative in the Company s CSF I notes and preferred interests.

NRG has 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, 2008, NRG had a deferred loss of $90 million in other comprehensive income compared to a deferred loss of $31 million in 2007.

Refinancing Expense

There was no refinancing activity in 2008. In 2007, NRG completed a $4.4 billion refinancing of the Company s Senior Credit Facility, resulting in a charge of $35 million from the write-off of deferred financing costs as the lenders for 45% of the Term Loan Facility either exited the financing or reduced their holdings and were replaced by other institutions.

Income Tax Expense

Income tax expense increased by $336 million for the year ended December 31, 2008, compared to 2007. The effective tax rate was 41.2% and 39.9% for the year ended December 31, 2008 and 2007, respectively

	Year Ended December 31, 2008	2007
	(In millions except as otherwise stated)	
Income from continuing operations before income taxes	$ 1,729	$ 946
Tax at 35%	605	331
State taxes, net of federal benefit	73	46
Foreign operations	(10)	(13)
Subpart F taxable income	2	
Valuation allowance, including change in state effective rate	(12)	6
Change in state effective tax rate	(11)	
Change in local German effective tax rates		(29)
Foreign dividends	32	26
Non-deductible interest	26	10
Permanent differences, reserves, other	8	
Income tax expense	$ 713	$ 377

Effective income tax rate	41.2%	39.9%

The increase in income tax expense was primarily due to:

Increase in income pre-tax income increased by $783 million, with a corresponding increase of $305 million in income tax expense.

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

- o *Taxable dividends from foreign subsidiaries* due to the provision of deferred taxes in 2008 on foreign income no longer expected to be permanently reinvested overseas offset by decreased dividends from foreign operations in the current year, tax expense increased by approximately $6 million as compared to 2007.

- o *Non-deductible interest on CAGR Settlement* the Company s $45 million settlement of the embedded derivative in its CSF I notes and preferred interests resulted in an additional income tax expense of $16 million in 2008 as compared to the same period in 2007.

- o *Change in German tax rate* as a result of revaluing our deferred tax assets, income tax expense benefited by $29 million in 2007, with no comparable benefit in 2008.

- o *Valuation Allowance* the Company generated capital gains in 2008 primarily due to the sale of ITISA and derivative contracts that are eligible for capital treatment for tax purposes. These gains enabled NRG to reduce our valuation allowance against capital loss carryforwards. In addition, applicable changes to the state and local effective tax rate are captured in the current period. This resulted in a decrease of $18 million income tax expense in 2008 as compared to 2007.

- o *Change in state effective tax rate* the Company reduced its domestic state and local deferred income tax rate from 7% to 6% in the current period.

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

Discontinued operations included ITISA results for 2008 and the same period in 2007. NRG classifies as discontinued operations the income from operations and gains/losses recognized on the sale of projects that were sold or have met the required criteria for such classification pending final disposition. For 2008 and the same period in 2007, NRG recorded income from discontinued operations, net of income tax expense, of $172 million and $17 million, respectively. NRG closed the sale of ITISA during the second quarter 2008 and recognized an after-tax gain of $164 million.

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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, 2007	2006	Change %
	(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	(97)
Contract amortization	242	628	(61)
Thermal revenue	125	124	1
Hedge Reset		(129)	(100)
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

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.

- o *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 economic hedges that do not qualify for hedge accounting, ineffectiveness on cash flow hedges, and trading activities. 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 (losses)/gains on open positions related to trading activity	(1)	26	24	49

Subtotal mark-to-market results	(66)	(16)	5	(77)
Total derivative (losses)/gains	$ (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 $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* cost of energy decreased by $95 million for the year ended December 31, 2007, compared to 2006. This decrease 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 decrease was due to a reduction of 2.7 million MWh in gas-fired generation as a result of cooler summer weather, coupled with greater economic purchases from the 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 the 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 include 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 increase was because the state s franchise tax was assessed based on the Company s total debt and equity that rose significantly following the acquisition of Texas Genco.

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.

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 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 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 Facility 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 Facility 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 Loan Facility 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:

- o *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.
- o *Taxable dividends from foreign subsidiaries* in January 2007, the Company transferred the proceeds from the sale of its Flinders assets to the US creating additional income tax expense of approximately $25 million.
- o *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.
- o *Non-deductible interest* interest expense from the stock buybacks from Phase I of the Company s Capital Allocation Program was non-deductible for income tax purposes, thus increasing income tax expense by approximately $7 million.
- o *Change in state effective tax rate* the state effective tax rate remained 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.
- o *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.
- o *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

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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Results of Operations Regional Discussions

Texas Region

2008 compared to 2007

The following table provides selected financial information for the Texas region for the year ended December 31, 2008, and the period ended December 31, 2007.

	Year Ended December 31, 2008	Year Ended December 31, 2007	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 2,870	$ 2,698	6%
Capacity revenue	493	363	36
Risk management activities	318	(33)	N/A
Contract amortization	255	219	16
Other revenues	90	40	125
Total operating revenues	4,026	3,287	22
Operating Costs and Expenses			
Cost of energy	1,240	1,181	5
Depreciation and amortization	451	469	(4)
Other operating expenses	650	668	(3)
Operating Income	$ 1,685	$ 969	74
MWh sold (in thousands)	47,806	49,220	(3)
MWh generated (in thousands)	46,937	47,779	(2)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 96.53	$ 62.00	56
Cooling Degree Days, or CDDs[a]	2,719	2,707	
CDD s 30 year rolling average	2,647	2,647	
Heating Degree Days, or HDDs[a]	1,961	1,949	1
HDD s 30 year rolling average	2,007	1,997	1%

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

Operating Income

Operating income increased by $716 million for the year ended December 31, 2008, compared to the same period in 2007, primarily due to:

Energy revenues increased by $172 million due to higher merchant energy revenue as a result of higher power prices and sales volumes offset by lower contract energy revenue.

Capacity revenue increased by $130 million due to a greater proportion of base-load contracts which contain a capacity component.

Risk management activities an increase of $351 million was primarily due to $479 million in greater unrealized derivative gains offset by $128 million in greater realized losses on settled financial transactions. These changes reflect a reduction in forward power and gas prices at the close of the year ended December 31, 2008.

These increases were offset by:

Cost of energy increased by $59 million reflecting the effects of increased natural gas and coal prices.

Operating Revenues

Total operating revenues from the Texas region increased by $739 million during the year ended December 31, 2008, compared to 2007 due to the following:

Risk management activities gains of $318 million were recognized for the year ended December 31, 2008, compared to a $33 million loss in the same period in 2007. The $318 million included $413 million of unrealized mark-to-market gains and $95 million in settled losses, or financial revenue. The $413 million was the net effect of a $400 million gain from economic hedge positions and a $25 million loss on reversals of mark-to-market gains on economic hedges. In addition, there were $37 million in unrealized mark-to-market gains on trading transactions combined with a $1 million gain on reversals of mark-to-market losses on trading activity. The $400 million gain from economic hedges incorporated $424 million in unrealized gains in the value of forward sales of electricity and fuel driven by lower power and natural gas prices. These hedges were considered effective economic hedges that do not receive cash flow hedge accounting treatment. The remaining $24 million in losses were from hedge ineffectiveness which was driven by decreasing gas prices while power prices decreased at a slower pace.

Energy revenues increased by $172 million due to:

- *Energy prices* increased by $219 million due to a more favorable mix of merchant versus contract sales resulting in a 28% increase in merchant prices offset by a 14% decrease in contract energy prices.

- *Generation* decreased by 839 thousand MWh or 2%. This decrease in generation was due to a 3% decline in nuclear generation at STP, as a result of additional plant outages, and a 14% decline in overall gas plant generation for the year ended December 2008. Hurricane Ike in September 2008 caused major damage to the Houston area transmission grid which reduced significantly the demand for power causing a decrease in gas-fired generation. These declines were offset by a 1% increase in coal generation in 2008.

Capacity revenue increased by $130 million due to a greater proportion of base-load contracts which contain a capacity component.

Other revenues increased by $50 million related to a $23 million increase in ancillary services revenue in 2008, a $22 million increase of allocations for trading of emission allowances and carbon financial instruments, and increased activity in trading natural gas and coal of $4 million.

Contract amortization revenue increased by $36 million due to the volume of contracted energy being positively affected by a greater spread between contract prices and market prices used in the Texas Genco purchase accounting.

Cost of Energy

Cost of energy for the Texas region increased by $59 million for the year ended December 31, 2008, compared to 2007 due to the following:

Natural gas costs increased by $99 million due to a 28% rise in average gas prices offset by a 14% decrease in gas-fired generation.

Coal costs increased by $44 million due to higher coal prices and the settlement of a coal contract dispute.

Ancillary services increased by $14 million due to a $16 million rise in ancillary service costs purchased through ERCOT, offset by a $2 million decrease in other purchased ancillary services costs.

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These increases were partially offset by:

Amortized contract costs decreased by $59 million due to a $36 million decrease in the amortization of water supply contracts which ended in 2007. In addition, the amortization of coal contracts decreased by a net $22 million as a result of a reduction in expense related to in-the-money coal contract amortization. These contracts were established under Texas Genco purchase accounting.

Nuclear fuel expense decreased by $19 million as amortization of nuclear fuel inventory established under Texas Genco purchase accounting ended in early 2008.

Purchased power decreased by $26 million due to lower forced outage rates at the region s baseload plants.

Other Operating Expenses

Other operating expenses for the Texas region decreased by $18 million for the year ended December 31, 2008, compared to 2007 due to the following:

Development costs decreased by $59 million primarily due to the initial costs for developing the nuclear units 3 and 4 at STP associated with the *Repowering*NRG initiative that began in 2007. Costs for STP nuclear units 3 and 4 are being capitalized in 2008.

This decrease was primarily offset by:

Operations & maintenance expense increased by $32 million due to an additional planned outage at STP and the acceleration of planned outages at the baseload plants.

General and Administrative expense increased by $10 million driven by higher corporate allocations.

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2007 compared to 2006

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)	(100)
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.

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 the 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 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.

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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 decrease 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 the ERCOT and increased baseload generation. Coal expenses, excluding January 2007, decreased by $13 million due to a 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 increase 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 were $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

2008 compared to 2007

The following table provides selected financial information for the Northeast region for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	2007	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 1,064	$ 1,104	(4)%
Capacity revenue	415	402	3
Risk management activities	85	27	215
Other revenues	66	72	(8)
Total operating revenues	1,630	1,605	2
Operating Costs and Expenses			
Cost of energy	695	641	8
Depreciation and amortization	109	102	7
Other operating expenses	392	404	(3)
Operating Income	$ 434	$ 458	(5)
MWh sold (in thousands)	13,349	14,163	(6)
MWh generated (in thousands)	13,349	14,163	(6)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 91.70	$ 76.37	20
Cooling Degree Days, or CDDs[(a)]	611	702	(13)
CDD s 30 year rolling average	537	537	
Heating Degree Days, or HDDs[(a)]	6,057	6,074	
HDD s 30 year rolling average	6,294	6,261	1%

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

Operating Income

Operating income decreased by $24 million for the year ended December 31, 2008, compared to 2007, due to:

Cost of energy increased by $54 million due to higher coal costs, increased coal transportation surcharges and higher natural gas prices. The increase was offset by lower oil costs from lower oil-fired generation.

This unfavorable variance was offset by:

Operating revenues increased by $25 million due to higher capacity revenue and risk management revenues partially offset by lower energy revenue.

Other operating expenses decreased by $12 million due to lower major maintenance expenses and property taxes offset by higher utilities expense.

Operating Revenues

Operating revenues increased by $25 million for the year ended December 31, 2008, compared to 2007, due to:

Risk management activities gains of $85 million were recorded for the year ended December 31, 2008, compared to gains of $27 million during the same period in 2007. The $85 million gain includes $82 million of unrealized mark-to-market gains and $3 million of gains in settled transactions, or financial revenue. The $82 million unrealized gains is the net effect of a $96 million gain from economic hedge positions, the $13 million loss due to the reversal of previously recognized mark-to-market gains on economic hedges, the $14 million loss due to the reversal of mark-to-market gains on trading activity and $13 million in unrealized mark-to-market gains on trading activity. Gains are driven by increases in power and gas prices.

Capacity revenues increased by $13 million due to:

- *PJM* capacity revenues increased by $20 million reflecting recognition of a year of revenue from the RPM capacity market (effective on June 1, 2007) in 2008 compared to seven months in 2007.
- *NEPOOL* capacity revenues increased $11 million due to increased revenue recognized on the Norwalk RMR contract (effective on June 19, 2007) in 2008 compared to seven months in 2007.
- *NYISO* capacity revenues decreased by $18 million due to unfavorable market prices. The lower capacity market prices are a result of NYISO s reductions in Installed Reserve Margins and ICAP in-city mitigation rules effective March 2008. These decreases were offset by higher capacity contract revenue.

These gains were offset by:

Energy revenues decreased by $40 million due to:

- *Energy prices* increased by a net $26 million. An average 6% rise in merchant energy prices resulted in an increase of $64 million. This increase was offset by lower contract revenue of $38 million driven by higher net costs incurred to service PJM contracts as a result of the increase in market energy prices.
- *Generation* decreased by $66 million due to a net 6% decrease in generation. The decrease in generation represented a 55% decrease in oil-fired generation as these oil-fired plants were not dispatched due to 41% higher average oil prices. In addition, there was a 12% decrease in gas-fired generation related to a cooler summer in 2008 as compared to 2007. Coal generation was flat in 2008 compared to 2007.

Other revenues decreased by $6 million due to lower allocations of net physical sales in 2008 of $17 million offset by higher allocations for trading of emission allowances and carbon financial instruments of $10 million.

Cost of Energy

Cost of energy increased by $54 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Coal costs increased by $61 million due to higher coal costs and fuel transportation surcharges.

Natural gas costs increased by $22 million, despite 12% lower generation, due to a 32% higher average natural gas prices.

These increases were offset by:

Oil costs decreased by $27 million due to lower oil-fired generation of 55% as these plants were not dispatched in 2008 due to 41% higher average oil prices.

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Other Operating Expenses

Other operating expenses decreased by $12 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Major Maintenance decreased $18 million as a result of less outage work at the Norwalk and Indian River plants.

Property taxes decreased $10 million due to $4 million in property tax credits received in 2008 at our New York City plants and higher property credits received in 2008 at our Western New York plants.

These decreases were offset by:

Utilities expense increased by $16 million as a result of a $19 million benefit included in the 2007 utilities cost due to a lower than planned settlement of the station service agreement with CL&P.

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	Year Ended December 31, 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.

o *Generation* increased by 6%, primarily driven by increases at the region s Arthur Kill, Oswego and Indian River plants. The Arthur Kill plant increased generation by 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.

o *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.

o *NEPOOL* The region s NEPOOL assets benefited from the new LFRM market and transition capacity market, both of which were introduced in the fourth quarter 2006. Capacity revenues increased by $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.

o

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.

South Central Region

2008 compared to 2007

The following table provides selected financial information for the South Central region for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 478	$ 404	18%
Capacity revenue	233	221	5
Risk management activities	10	10	
Contract amortization	23	23	
Other revenues	2		N/A
Total operating revenues	746	658	13
Operating Costs and Expenses			
Cost of energy	468	412	14
Depreciation and amortization	67	68	(1)
Other operating expenses	111	121	(8)
Operating Income	$ 100	$ 57	75
MWh sold (in thousands)	12,447	12,452	
MWh generated (in thousands)	11,148	10,930	2
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 71.25	$ 59.62	20
Cooling Degree Days, or CDDs[(a)]	1,618	1,963	(18)
CDD s 30 year rolling average	1,547	1,547	
Heating Degree Days, or HDDs[(a)]	3,672	3,236	13
HDD s 30 year rolling average	3,623	3,604	1%

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

Operating Income

Operating income increased by $43 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Operating revenues increased by $88 million due to increases in energy revenue and capacity revenue.

Cost of energy increased by $56 million due to higher purchased energy, coal transportation costs, natural gas and transmission costs.

Operating Revenues

Operating revenues increased by $88 million for the year ended December 31, 2008, compared to 2007, due to:

Energy revenues increased by $74 million due to higher merchant energy revenues. A decline in contract sales of 577 thousand MWh allowed for increased sales into the merchant market at higher prices. Merchant energy sales increased 573 thousand MWh. Revenue from contract load was flat as higher fuel cost pass-through adjustments for the region s cooperative customers were offset by reductions in contract volume to other contract customers.

Capacity revenues increased by $12 million. Capacity payments from the region s cooperative customers increased by $10 million due to new peak loads set by the region s cooperative customers and increased transmission and environmental pass-through costs. Increased RPM capacity payments from the region s Rockford facilities in the PJM market contributed an additional $8 million. These increases were offset by a reduction in contract volumes to other customers of $6 million.

Risk Management Activities gains of $10 million were recognized during 2008 compared to $10 million in gains recognized during the same period in 2007. Unrealized gains in 2008 of $26 million were offset by realized losses of $16 million. The $26 million unrealized gain was the net effect of a $45 million unrealized mark-to-market gain from trading activities in the region offset by the reversal of $19 million loss of previously recognized mark-to-market gains on trading activity. Unrealized gains were primarily driven by decreases in power and gas prices relative to our forward positions.

Cost of Energy

Cost of energy increased by $56 million for the year ended December 31, 2008, compared to 2007, due to:

Purchased energy increased by $16 million reflecting a 21% increase in the average cost per MWh of purchased energy which reflects higher gas costs associated with the region s tolling agreements. This increase was offset by an 8% decrease in purchased MWh as increased plant availability and lower contract load requirements reduced the need to purchase power.

Coal costs increased by $16 million due to a $2 per ton increase in fuel transportation surcharges combined with a 1% increase in coal generation. These increases were offset by a $3 million decrease in allocated rail car lease fees.

Natural gas costs increased $14 million. The region s Bayou Cove and Big Cajun I peaker plants ran extensively to support transmission system stability after hurricane Gustav in September 2008.

Transmission costs increased by $9 million due to additional point-to-point transmission costs driven by an increase in merchant energy sales.

Other Operating Expenses

Other operating expenses decreased by approximately $10 million for the year ended December 31, 2008, compared to 2007, due to:

G&A Expense Franchise tax decreased by $5 million due to retroactive charges recorded in 2007. The Louisiana state franchise tax is assessed on the Company s total debt and equity that significantly increased following the Acquisition of Texas Genco. This decrease was offset by $6 million in higher corporate allocations in 2008 compared to the same period in 2007.

Operating and maintenance expense Major maintenance decreased by $9 million due to more extensive spring outage work performed at the Big Cajun II plant in 2007 compared to the same period in 2008. Normal maintenance rose $2 million as a result of increased forced outages and higher contractor costs. Asset retirements decreased by $4 million reflecting disposals associated with the 2007 outage work at Big Cajun II.

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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	Year Ended December 31, 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	(100)
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.

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.

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West Region

2008 compared to 2007

The following table provides selected financial information for the West region for the years ended December 31, 2008, and 2007:

	Year Ended December 31,		Change
	2008	2007	%
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 39	$ 4	N/A
Capacity revenue	125	122	2%
Risk management activities			N/A
Other revenues	7	1	N/A
Total operating revenues	171	127	35
Operating Costs and Expenses			
Cost of energy	35	5	N/A
Depreciation and amortization	8	3	167
Other operating expenses	70	80	(13)
Operating Income	$ 58	$ 39	49
MWh sold (in thousands)	1,532	1,246	23
MWh generated (in thousands)	1,532	1,246	23
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 82.62	$ 66.52	24
Cooling Degree Days, or CDDs[(a)]	953	785	21
CDD s 30 year rolling average	704	704	
Heating Degree Days, or HDDs[(a)]	3,190	3,048	5%
HDD s 30 year rolling average	3,243	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 increased by $19 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Energy revenues increased by $35 million due to the 2008 dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other operating expense decreased by $10 million as a result of a $5 million reduction in *Repowering*NRG expenses due to the capitalization of cost for the El Segundo Energy Center project in 2008. In addition there was a $3 million reduction in lease expenses in 2008 and the recognition of a $2 million environmental liability for the El Segundo plant in 2007.

Other revenues increased by $6 million due to higher allocations for trading of emission allowances in 2008.

Capacity revenues increased by $3 million primarily due to the tolling agreement at the Long Beach plant partially offset by the expiration of a two year tolling agreement at the El Segundo facility:

- o *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. The plant contributed $15 million in incremental capacity revenues for the year ended December 31, 2008.
- o *El Segundo* The expiration of the two year tolling agreement at the end of April resulted in a decrease of $11 million in capacity revenues for the year ended December 31, 2008.

These increases were partially offset by:

Cost of energy increased by $30 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Depreciation and amortization increased by $5 million, reflecting depreciation associated with the repowered plant at the Long Beach generating facility.

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	Year Ended December 31, 2006	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 4	$ 75	(95)%
Capacity revenue	122	68	79
Risk management activities		(3)	100
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.

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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* The repowered plant at the Long Beach generating facility 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 its 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 a 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.

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Liquidity and Capital Resources

Liquidity Position

As of December 31, 2008 and 2007, NRG s liquidity, excluding collateral received, was approximately $3.4 billion and $2.7 billion, respectively, comprised of the following:

	As of December 31, 2008	2007
	(In millions)	
Cash and cash equivalents	$ 1,494	$ 1,132
Funds deposited by counterparties	754	
Restricted cash	16	29
Total cash	2,264	1,161
Synthetic Letter of Credit Facility availability	860	557
Revolver Credit Facility availability	1,000	997
Total liquidity	4,124	2,715
Less: Funds deposited as collateral by hedge counterparties	(760)	
Total liquidity, excluding collateral received	$ 3,364	$ 2,715

For the year ended December 31, 2008, total liquidity increased by $1.4 billion due to a rise in funds deposited of $754 million as well as higher cash balances of $362 million. Changes in cash balances are further discussed hereinafter under *Cash Flow Discussion*. Cash and cash equivalents and funds deposited by counterparties at December 31, 2008 are predominantly held in money market funds invested in treasury securities or treasury repurchase agreements.

The line item Funds deposited by counterparties consist of cash collateral received from hedge counterparties in support of energy risk management activities, and it is the Company s intention as of December 31, 2008 to limit the use of these funds. The increase in these amounts is due to the in-the-money position of our transactions following the drop in commodity prices since the summer of 2008. Depending on market fluctuation and the settlement of the underlying contracts, the Company will refund this collateral to the counterparties pursuant to the terms and conditions of the underlying trades. The Company s balance sheet reflects a liability for cash collateral received within current liabilities.

Management believes that the Company s liquidity position 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 net 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. As of December 31, 2008, NRG s credit ratings are on positive watch from both S&P and Moody s rating agencies.

The following table summarizes the credit ratings for NRG Energy, Inc., its Term Loan Facility and its senior notes as of December 31, 2008:

	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 Facility	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

As of December 31, 2008, NRG has a Senior Credit Facility which is 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 $1.3 billion senior first priority secured synthetic letter of credit facility, or the Synthetic Letter of Credit Facility. The Senior Credit Facility was last amended on June 8, 2007. As of December 31, 2008, NRG had issued $440 million of letters of credit under the Synthetic Letter of Credit Facility, leaving $860 million available for future issuances. Under the Revolving Credit Facility, as of December 31, 2008, NRG had not issued any letters of credit.

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets. 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 out-of-the-money hedge agreements for forward sales of power or MWh equivalents. To the extent that the underlying hedge positions for a counterparty are in-the-money to NRG, the counterparty would have no claim under the lien program. The lien program limits the volume that can be hedged, not the value of underlying out-of-the money positions. The first lien program does not require NRG to post collateral above any threshold amount of exposure. 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 for the first 60 months and then declining thereafter. Net exposure to a counterparty on all trades must be positively correlated to the price of the relevant commodity for the first lien to be available to that counterparty. The first and second lien structure is not subject to unwind or termination upon a ratings downgrade of a counterparty and has no stated maturity date.

The Company s lien counterparties may have a claim on our assets to the extent market prices exceed the hedged price. As of December 31, 2008 and February 2, 2009, the first lien exposure of net out-of-the-money positions to counterparties on hedges was $88 million and $43 million, respectively. As of December 31, 2008 and February 2, 2009, there was no exposure to out-of-the-money positions to counterparties on hedges under the second lien.

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 2, 2009:

Equivalent Net Sales Secured by First and Second Lien Structure[a]	**2009**	**2010**	**2011**	**2012**	**2013**
In MW[b]	4,967	4,600	3,788	2,196	828
As a percentage of total forecasted baseload capacity[c]	71%	67%	56%	33%	12%

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

(b) 2009 MW value consists of March through December positions only.

(c) Forecasted baseload capacity under the first and second lien structure represents 80% of the total Company s baseload assets.

Common Stock Finance I Debt

The Company s Senior Credit Facility and Senior Notes indentures contain restricted payment provisions limiting the use of funds for transactions such as common share repurchases. To maintain restricted payment capacity under the Senior Notes indentures, in March 2008 the Company executed an arrangement with CS to extend maturities of CSF I s notes and preferred interests from October 2008 to June 2010. In addition, the settlement date of an embedded derivative, or CSF I CAGR, which is based on NRG s share price appreciation above a threshold price, was extended 30 days to early December 2008. As part of this extension arrangement, the Company contributed 795,503 treasury shares to CSF I as additional collateral to maintain a blended interest rate in the CSF I facility of approximately 7.5%. Accordingly, the amount due at maturity in June 2010 for the CSF I notes and preferred interests will be $248 million. In August 2008, the Company amended the CSF I notes and preferred interests to early settle the CSF I CAGR. Accordingly, NRG made a cash payment of $45 million to CS for the benefit of CSF I, which was recorded to interest expense in the Company s Consolidated Statement of Operations.

Asset Sales

ITISA On April 28, 2008, NRG completed the sale of its 100% interest in Tosli, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 consolidated balance sheet. 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: (i) commercial operations activities; (ii) debt service obligations; (iii) capital expenditures including *Repowering*NRG and environmental; and (iv) corporate financial transactions including return of capital to shareholders.

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, 2008, commercial operations had total cash collateral outstanding of $492 million, and $283 million outstanding in letters of credit to third parties primarily to support its economic hedging activities. As of December 31, 2008, total collateral held from counterparties was $788 million, including $6 million of restricted cash, and $28 million of letters of credit.

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.

Debt Service Obligations

NRG must annually offer a portion of its excess cash flow (as defined in the Senior Credit Facility) to its first lien lenders under the Term Loan Facility. 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 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 for 2008, and, as such, the Company has reclassified approximately

$197 million of Term Loan Facility maturity from a non-current to a current liability as of December 31, 2008. The mandatory annual offer required for 2007 was $446 million, against which the Company made a $300 million prepayment in December 2007. With this prepayment, the Company met a financial ratio by the end of 2007 that resulted in a 0.25% reduction in the interest rate on both its Term Loan Facility and Synthetic Letter of Credit Facility which resulted in approximately $8 million in pre-tax interest savings during 2008. Of the remaining $146 million, the lenders accepted a repayment of $143 million in March 2008. The amount retained by the Company was used for investments, capital expenditures and other items as defined by the Senior Credit Facility.

As of December 31, 2008, NRG had approximately $4.7 billion in aggregate principal amount of unsecured high yield notes or Senior Notes, had approximately $2.6 billion in principal amount outstanding under the Term Loan Facility, and had issued $440 million of letters of credit under the Company s $1.3 billion Synthetic Letter of Credit Facility. The Revolving Credit Facility matures on February 2, 2011 and the Synthetic Letter of Credit Facility matures on February 1, 2013.

Principal payments on debt and capital leases as of December 31, 2008 are due in the following periods:

Subsidiary/Description	2009	2010	2011	2012	2013	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 Facility, due 2013	228	32	31	32	2,319		2,642
CSF notes and preferred interests, due 2009 and 2010	143	190					333
NRG Energy Center Minneapolis LLC, due 2013 and 2017	11	11	12	13	10	27	84
Nuclear Innovation North America LLC, due 2011			10				10
NRG Repowering Holdings LLC, due 2011			10				10
NRG Peaker Finance Co. LLC, due June 2019	15	20	21	22	23	165	266
Subtotal Debt, Bonds and Notes	397	253	84	67	2,352	4,892	8,045
Capital Lease:							
Saale Energie GmbH, Schkopau	72	12	6	4	4	44	142
Total Payments and Capital Leases	$ 469	$ 265	$ 90	$ 71	$ 2,356	$ 4,936	$ 8,187

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Capital Expenditures

For the year ended December 31, 2008, the Company s capital expenditures, including accruals, were approximately $1.0 billion, of which $645 million was related to *Repowering*NRG projects. The following table summarizes the Company s capital expenditures for the year ended December 31, 2008 and the estimated capital expenditure and repowering investments forecast for 2009.

	Maintenance	Environmental	Repowering	Total
		(In millions)		
Northeast	$ 32	$ 157	$ 19	$ 208
Texas	115	26	97	238
South Central	9	5		14
West	5		30	35
Wind			398	398
NINA			101	101
Other	21			21
Total	$ 182	$ 188	$ 645	$ 1,015
Estimated capital expenditures for 2009	$ 255	$ 256	$ 256	$ 767

*Repowering*NRG *capital expenditures and investments* *Repowering*NRG project capital expenditures consisted of approximately $218 million for wind turbines and construction related costs for the Elbow Creek wind farm project which became commercially operational in December 2008 and $180 million in turbine purchases for other wind projects currently under development. In addition, the Company s *Repowering*NRG capital expenditures included $97 million related to the construction of Cedar Bayou Unit 4 in Texas, $101 million related to the development of STP Units 3 and 4 in Texas, $30 million for the repowering of the El Segundo generating station in California, and $19 million for the construction of Cos Cob in Connecticut.

The Company s estimated repowering capital expenditures for 2009 are expected to be approximately $256 million, of which capital expenditures related to STP units 3 and 4 will be approximately $145 million, the construction of Cedar Bayou Unit 4 anticipated to be approximately $22 million, and the balance of the Company s repowering capital expenditures related to the purchase of additional wind turbines. The Company also anticipates receiving approximately $145 million in third party equity investments related to its *Repowering*NRG projects in 2009.

Related to *Repowering*NRG, the Company contributed equity of approximately $84 million to its Sherbino wind farm joint venture project with BP in 2008 which became commercially operational in October 2008.

Major maintenance and environmental capital expenditures The Company s baghouse project at its Huntley and Dunkirk plants resulted in environmental capital expenditures of $124 million for the year ended December 31, 2008. Other capital expenditures included $44 million for STP fuel and $71 million in maintenance capital expenditures in Texas primarily related to the W.A. Parish and Limestone plants.

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 region through Solid Waste Disposal Bonds utilizing tax exempt financing, and expects to draw upon such funds during 2009.

Loans to affiliates During 2008 the Company loaned approximately $36 million in funds to GenConn Energy LLC, a 50/50 joint venture vehicle of NRG and the United Illuminating Company as a part of the Devon and Middletown plant projects. These loans, which are in the form of an interest bearing note, mature in 2009, at which point GenConn Energy LLC s construction costs are expected to be funded through equity of NRG and the United Illuminating Company and non-recourse project level financing.

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Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2009 through 2013 to meet NRG s environmental commitments will be approximately $1.2 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with federal and state air quality rules and consent orders, 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. While this estimate reflects schedules and controls to meet anticipated reduction requirements, the full impact on the scope and timing of environmental retrofits cannot be determined until issuance of final rules by the USEPA.

The following table summarizes the estimated environmental capital expenditures for the referenced periods by region:

	Texas	Northeast	South Central	Total
2009	$	$ 256	$	$ 256
2010	8	213	57	278
2011	17	175	116	308
2012	29	67	114	210
2013	21	3	74	98
Total	$ 75	$ 714	$ 361	$ 1,150

Capital Allocation

2008 Capital Allocation Plan In December 2007, the Company initiated its 2008 Capital Allocation Plan, with the repurchase of 2,037,700 shares of NRG common stock during that month for approximately $85 million. In February 2008, the Company s Board of Directors authorized an additional $200 million in common share repurchases that raised the total 2008 Capital Allocation Plan to approximately $300 million. In the first quarter 2008, the Company repurchased 1,281,600 shares of NRG common stock for approximately $55 million. In the third quarter 2008, the Company repurchased an additional 3,410,283 of NRG common stock in the open market for approximately $130 million. As of December 31, 2008, NRG had repurchased a total of 6,729,583 shares of NRG common stock at a cost of approximately $270 million as part of its 2008 Capital Allocation Plan.

2009 Capital Allocation Plan On October 30, 2008, the Company announced its 2009 Capital Allocation Plan to purchase an additional $300 million in common stock, subject to restrictions under US securities laws. As part of the 2009 plan, the Company will invest over $511 million in maintenance and environmental capital expenditures in existing assets in 2009 and $256 million in investment in projects under *Repowering*NRG that are currently under construction or for which there exists current obligations. Finally, in addition to scheduled debt amortization payment, in the first quarter 2009 the Company will offer its first lien lenders $197 million of its 2008 excess cash flow (as defined in the Senior Credit Facility).

Preferred Stock Dividend Payments

For the year ended December 31, 2008, NRG paid approximately $29 million, $17 million and $9 million in dividend payments to holders of the Company s 5.75%, 4% and 3.625% Preferred Stock.

Benefit Plans Obligations

As of December 31, 2008, NRG contributed $99 million towards its three defined benefit pension plans to meet the Company s 2008 benefit obligation, $35 million of which was to partially fund the plans as a result of the weak market performance of plan assets in 2008. Based on the Company s December 31, 2008 measurement of its benefit obligation for its three defined benefit pension plans, the Company is expected to contribute another $60 million to these plans during 2009, $29 million of which also relates to the Company s 2008 benefit obligation.

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Cash Flow Discussion

2008 compared to 2007

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,		
	2008	2007	Change
		(In millions)	
Net cash provided by operating activities	$ 1,434	$ 1,517	$ (83)
Net cash used by investing activities	(672)	(327)	(345)
Net cash used by financing activities	(442)	(814)	372

Net Cash Provided By Operating Activities

For the year ended December 31, 2008, net cash provided by operating activities decreased by $83 million compared to the same period in 2007. The difference was due to:

Collateral paid In 2008, higher cash collateral paid to support the Company s hedging and trading activities decreased cash from operations by $292 million as compared to the same period in 2007.

Working capital In 2008, the cash provided by working capital items increased by $196 million. Changes in option premiums collected from 2007 to 2008 classified in other current liabilities increased as a result of the deferral of option premium revenue to 2009 to match revenues with option expiration dates. Further, changes to account receivable were caused by higher energy revenues in December 2007 as compared to December 2008 and changes to accounts payable were caused by reduced maintenance expenses incurred in December 2007 as compared to December 2008.

Net Cash Used By Investing Activities

For the year ended December 31, 2008, net cash used in investing activities was approximately $345 million more than the same period in 2007. This was due to:

Capital expenditures NRG s capital expenditures increased by $418 million due to *Repowering*NRG projects, primarily related to $398 million for wind turbines and construction activities related to Elbow Creek and other wind projects currently under development.

Sale of discontinued operations Proceeds from the sale of ITISA, net of cash divested, were $241 million in 2008.

Asset sales The Company received $14 million in proceeds primarily from the sale of rail cars in 2008 compared to proceeds of $57 million for the sale of Red Bluff and Chowchilla II power plants and equipment in the same period in 2007 for a net decrease in cash of $43 million.

Trading of emission allowances Net purchases and sales of emission allowances resulted in a decrease in cash of $44 million for 2008 as compared to 2007.

Equity Contribution The Company contributed approximately $84 million to its equity investment in Sherbino.

Net Cash Used By Financing Activities

For year ended December 31, 2008, net cash used by financing activities decreased by approximately $372 million compared to 2007, due to:

Term Loan Facility debt payment In 2008, the Company paid down $174 million of its Term Loan Facility, including the payment of excess cash flow, as discussed above under *Debt Service Obligations*. The Company paid down $332 million of its Term Loan Facility during 2007 for a net cash increase of $158 million for the year ended 2008 compared to the same period in 2007.

Share repurchase During 2008, the Company repurchased approximately $185 million shares of NRG common stock, compared to $353 million for 2007 for a net $168 million increase to cash for the year ended 2008 compared to the same period in 2007.

Sale of minority interest The Company received $50 million in proceeds from the sale of minority interest in NINA in the first half of 2008.

Payment of financing element of acquired derivatives For 2008, the Company paid approximately $43 million for the settlement of gas swaps related to the acquisition of Texas Genco in 2006.

Issuance of debt During 2008 the Company received $20 million in proceeds from borrowings made by its subsidiaries.

NOL s, Deferred Tax Assets and FIN 48 Implications

As of December 31, 2008, the Company had generated total domestic pre-tax book income of $1,644 million and foreign continuing pre-tax book income of $85 million. In addition, NRG has cumulative foreign NOL carryforwards of $239 million, of which $41 million will expire starting in 2011 through 2017 and of which $198 million do not have an expiration date.

In addition to these amounts, the Company has $527 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, we anticipate income tax payments of up to $100 million in 2009.

However, as the position remains uncertain, of the $527 million of tax effected unrecognized tax benefits, the Company has recorded a non-current tax liability of $208 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $208 million non-current tax liability for unrecognized tax benefits is due to taxable earnings for the period which there are no NOLs available to offset for financial statement purposes.

The Company has been contacted for examination by the Internal Revenue Service for years 2004 through 2006. The audit commenced during the third quarter 2008 and is expected to continue for approximately 18 to 24 months.

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 Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See also Item 15 Note 25, *Guarantees,* to the Consolidated Financial Statements for additional discussion.

Retained or Contingent Interests

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

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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, 2008, based on the Company s stock price, the embedded derivative was out-of-the-money and had no redemption value. See also Item 15 Note 13, *Capital Structure,* to the Consolidated Financial Statements for additional discussion.

On October 13, 2006, NRG, through its unrestricted wholly-owned subsidiaries CSF I and CSF II issued notes and preferred interests for the repurchase of NRG s common stock. Included in each agreement was a feature 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. In August 2008, the Company amended the CSF I notes and preferred interests to early settle the CSF I embedded derivative. Accordingly, NRG made a cash payment of $45 million to CS for the benefit of CSF I, which was recorded to interest expense in the Company s Consolidated Statement of Operations. As of December 31, 2008, based on the Company s stock price, the CSF II embedded derivative was out-of-the-money and had no redemption value. See also Item 15 Note 11, *Debt and Capital Leases,* to the Consolidated Financial Statements for additional discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments As of December 31, 2008, 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. One of these investments, GenConn Energy LLC, is a variable interest entity for which NRG is not the primary beneficiary. NRG s pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $135 million as of December 31, 2008. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 15 Note 14, *Investments Accounted for by the Equity Method,* to the Consolidated Financial Statements for additional discussion.

Letter of Credit Facilities The Company s $1.3 billion Synthetic Letter of Credit Facility is unfunded by NRG and is secured by a $1.3 billion cash deposit at Deutsche Bank AG, New York Branch that was funded using proceeds from the Term Loan Facility 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.

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 contingent obligations for guarantee. See also Item 15 Note 11, *Debt and Capital Leases*, Note 21, *Commitments and Contingencies*, and Note 25, *Guarantees* , to the Consolidated Financial Statements for additional discussion.

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Contractual Cash Obligations	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total[b]	2007 Total
	By Remaining Maturity at December 31, 2008 (In millions)					
Long-term debt (including estimated interest)	$ 858	$ 1,316	$ 3,267	$ 5,701	$ 11,142	$ 12,301
Capital lease obligations (including estimated interest)	87	37	25	172	321	390
Operating leases	43	79	62	193	377	420
*Repowering*NRG project commitments	27				27	352
Fuel purchase and transportation obligations[a]	1,513	477	182	206	2,378	3,203
Pension minimum funding requirement[c]	65	95	34		194	196
Other postretirement benefits minimum funding requirement[d]	4	11	4		19	15
Total	$ 2,597	$ 2,015	$ 3,574	$ 6,272	$ 14,458	$ 16,877

(a) Includes only those coal transportation and lignite commitments for 2009 as no other nominations were made as of December 31, 2008. Natural gas nomination is through February 2010.

(b) Excludes $208 million non-current FIN 48 payable relating to NRG s uncertain tax benefits as the period of payment cannot be reasonably estimated.

(c) These amounts represent the Company s estimated minimum pension contributions required under the Pension Protection Act of 2006. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2013 is currently not available.

(d) These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2013 are currently not available.

Guarantees, Indemnifications and Other Contingent Obligations	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2007 Total
	By Remaining Maturity at December 31, 2008 (In millions)					
Synthetic letters of credit	$ 357	$ 83	$	$	$ 440	$ 743
Unfunded standby letters of credit and surety bonds	5				5	8
Asset sales guarantee obligations		112		17	129	148
Commercial sales arrangements	192	13		800	1,005	791
Other guarantees	24	30		26	80	32

Total	$ 578	$ 238	$	$ 843	$ 1,659	$ 1,722

Fair Value of Derivative Instruments

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

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

The tables below disclose the activities that include both exchange and 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, 2008, based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2008.

Derivative Activity Gains/(Losses)	**(In millions)**
Fair value of contracts as of December 31, 2007	$ (492)
Contracts realized or otherwise settled during the period	162
Changes in fair value	1,326
Fair value of contracts as of December 31, 2008	$ 996

	Fair Value of Contracts as of December 31, 2008				
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	$ (32)	$ 14	$	$	$ (18)
Prices provided by other external sources	614	114	283	(46)	965
Prices provided by models and other valuation methods	37	12			49
Total	$ 619	$ 140	$ 283	$ (46)	$ 996

A small portion of NRG s contracts are exchange-traded contracts with readily available quoted market prices. The majority of NRG s contracts are non exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company s prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote then the mid point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. The remainder of the assets and liabilities represent contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up 5% of the total fair value of all derivative contracts. The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that NRG s net exposure under a specific master agreement is an asset, the Company is using the counterparty s default swap rate. If the exposure under a specific master agreement is a liability, the Company is using NRG s default swap rate. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG s liabilities or that a market participant would be willing to pay for NRG s assets. As of December 31, 2008 the credit reserve resulted in a $22 million decrease in fair value which is composed of a $10 million gain in other comprehensive income, or OCI, and a $12 million gain in derivative revenue.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2008 and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts NRG holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

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The Company has elected to disclose derivative activity on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company s portfolio. As discussed in Item 7A *Commodity Price Risk*, NRG measures the sensitivity of the Company s portfolio to potential changes in market prices using Value at Risk, or VAR, a statistical model which attempts to predict risk of loss based on market price and volatility. NRG s risk management policy places a limit on one-day holding period VAR, which limits the Company s net open position. As the Company s trade-by-trade derivative accounting results in a gross-up of the Company s derivative assets and liabilities, the net derivative assets and liability position is a better indicator of our hedging activity. As of December 31, 2008, NRG s net derivative asset was $996 million, an increase to total fair value of $1,488 million as compared to December 31, 2007. This increase was primarily driven by decreases in gas and power prices as well as the roll-off of trades that settled during the period.

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 US. 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

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

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Accounting Policy	Judgments/Uncertainties Affecting Application
	Ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods
Impairment of Long Lived Assets	Recoverability of investment through future operations Regulatory and political environments and requirements Estimated useful lives of assets Environmental obligations and operational limitations Estimates of future cash flows Estimates of fair value (fresh start) Judgment about triggering events
Goodwill and Other Intangible Assets	Estimated useful lives for finite-lived intangible assets Judgment about impairment triggering events Estimates of reporting unit s fair value Fair value estimate of certain power sales and fuel contracts using forward pricing curves as of the closing date over the life of each contract
Contingencies	Estimated financial impact of event(s) Judgment about likelihood of event(s) occurring Regulatory and political environments and requirements

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 commodities based on the specific market in which the energy commodity is being purchased or sold, using externally available forward market pricing curves for all periods possible under the pricing model. In order to qualify derivative 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, 2008, NRG had a valuation allowance of approximately $359 million. This amount is comprised of U.S. domestic capital loss carryforwards and non-depreciable property of approximately $292 million, foreign net operating loss carryforwards of approximately $66 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, cumulative net operating losses of $245 million had been fully utilized with the exception of state NOLs. 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 and Australia. 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 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.

For the years ended December 31, 2008 and 2007, there were reductions of $23 million and $11 million, respectively, in income from continuing operation due to impairment of an investment in commercial paper. The Company recorded these impairments as a reduction to interest income. For the year ended December 31, 2006, there was no reduction in income from continuing operations due to an impairment.

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.

Goodwill and Other Intangible Assets

As part of the acquisition of Texas Genco, NRG recorded goodwill and intangible assets at its Texas segment reporting unit. The Company applied SFAS No. 141, *Business Combinations,* or SFAS 141, and 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 are tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available and segment management regularly reviews the operating results of those components. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary the Company s goodwill and/or intangible asset with indefinite lives will be impaired at that time.

The Company performed its annual goodwill impairment assessment as of December 31, 2008 for its Texas reporting unit, which is at the operating segment level. The impairment assessment included both income and

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market approaches, represented by discounted cash flow and earnings multiple methodologies that considered the following:

Income approach

a discounted cash flow valuation for the region s major solid fuel baseload plants that utilized the Company s six-year budget data and a market-derived earnings multiple terminal value, with such terminal value assessed for reasonableness by capitalizing the final year s cash flow with adjustments for expected inflation;

a discounted cash flow valuation for the tax benefit associated with the amortization of tax basis of the region s intangible assets;

a market approach valuation of the region s gas plants using market-derived earnings multiples of comparable power generators, with adjustments for the region s expected capital expenditure requirements;

Market approach

an overall market approach reasonableness test that reconciled NRG s current market value based upon the average percent of total company value represented by NRG Texas, as measured by four different earnings measures, each calculated over three different historical time periods. This market approach reasonableness test also considered sensitivity testing under a number of different implied control premium scenarios, including one with no premium.

The income approach methodologies were consistent with the approach for determining fair value at December 31, 2007 and 2006. Significant assumptions and judgments impacting the Company s goodwill impairment assessment included management s projections of operating results and capital expenditure requirements, risk-adjusted discount rates, market performance, and other factors. Under all methodologies, the calculated NRG Texas equity value exceeded the NRG Texas book value, and the Company concluded that goodwill was not impaired as of December 31, 2008.

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, oil, and emissions credits. 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 forwards, futures, swaps, and option contracts traded on various exchanges, such as New York Mercantile Exchange, or NYMEX, Intercontinental Exchange, or ICE, and Chicago Climate Exchange, or CCX, as well as 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 risk of the Company s portfolio using several analytical methods, including sensitivity tests, scenario tests, stress tests, position reports, and 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: (i) a lognormal distribution of prices, (ii) one-day holding period, (iii) a 95% confidence interval, (iv) a rolling 36-month forward looking period, and (v) market implied volatilities and historical price correlations.

As of December 31, 2008, 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 $43 million.

The following table summarizes average, maximum and minimum VAR for NRG for the year ended December 31, 2008 and 2007:

VAR		**In millions**
As of December 31, 2008	$	43
Average		50
Maximum		65
Minimum		35
As of December 31, 2007[(a)]	$	64
Average		28
Maximum		64
Minimum		14

(a) 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, 2008, for the entire term of these instruments entered into for both asset management and trading, was approximately $35 million primarily driven by asset-backed transactions.

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, 2008 was $1.9 billion.

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The maturities and notional amounts of each tranche of these swaps in connection with the Senior Credit Facility are as follows:

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

In addition to those listed above, the Company had the following additional interest rate swaps outstanding as of December 31, 2008:

	Notional Value	Maturity
Floating to fixed interest rate swap for NRG Peaker Financing LLC	$ 266 million	June 10, 2019
Fixed to floating interest rate swap for Senior notes, due 2014	$ 400 million	December 15, 2013

If all of the above swaps had been discontinued on December 31, 2008, the Company would have owed the counterparties approximately $156 million. Based on the investment grade rating of the counterparties, 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, 2008, a 1% change in interest rates would result in a $12.8 million change in interest expense on a rolling twelve month basis.

As of December 31, 2008, the Company s long-term debt fair value was $7.5 billion and the carrying amount was $8.0 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 $401 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 MMBtu increase or decrease in natural gas prices across the term of the marginable contracts for power and gas positions would cause a change in margin collateral outstanding of approximately $72 million as of December 31, 2008. In addition, a 0.25 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral of approximately $82 million as of December 31, 2008. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2008.

Under the second lien, NRG is required to post certain letter of credits as credit support for changes in commodity prices. As of December 31, 2008, $19 million in letters of credit are outstanding to second lien counterparties. With changes in commodity prices, the letters of credit could grow to $87 million, the cap under the agreements.

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 credit risk through credit policies that include: (i) an established credit approval process, (ii) a daily monitoring of counterparties 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 seeks to mitigate counterparty risk with a diversified portfolio of counterparties, including ten participants under its first and second lien structure. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at NRG to cover the credit risk of the counterparty until positions settle.

A sharp economic downturn in the US and overseas markets during the latter part of 2008 was prompted by a combination of factors: tight credit markets, speculation and fear over the health of the US and global financial systems, and weaker economic activity in general prompting fears of an economic recession. Under the current market dynamics, the Company has heightened its management and mitigation of counterparty credit risk by using credit limits, netting agreements, collateral thresholds, volumetric limits and other mitigation measures, where available. NRG avoids concentration of counterparties whenever possible and applies credit policies that include an evaluation of counterparties financial condition, collateral requirements and the use of standard agreements that allow for netting and other security.

As of December 31, 2008, total credit exposure to substantially all counterparties was $2.0 billion and NRG held collateral (cash and letters of credit) against those positions of $788 million resulting in a net exposure of $1.2 billion. Total credit exposure is discounted at the risk free rate.

The following table highlights the credit quality and the net counterparty credit exposure by industry sector. Net counterparty credit risk is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark to market and normal purchase and sale and non-derivative transactions. The exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	**Net Exposure[(a)] (% of Total)**
Coal producers	16%
Financial institutions	58
Utilities, energy, merchants and marketers	21
ISOs	5
Total as of December 31, 2008	100%

Category	**Net Exposure[(a)] (% of Total)**
Investment grade	81%
Non-Investment grade	8
Non-rated	11
Total as of December 31, 2008	100%

(a) Credit exposure excludes California tolling, uranium, coal transportation/railcar leases, New England Reliability Must-Run, cooperative load contracts and Texas Westmoreland coal contracts.

NRG has credit risk exposure to certain counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $241 million. No counterparty represents more than 20% of total net credit exposure. Approximately 80% of NRG s positions relating to credit risk roll-off by the end of 2011. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. 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.

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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, 2008, 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 US 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 and approximately $58 million in pre-tax unrealized income reflected in the currency translation adjustment component of 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 the effectiveness of the design and operation 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 2008 Annual Report to Shareholders.

Changes in Internal Control over Financial Reporting

Except for the remediation of the material weakness discussed below, there were no changes in the Company s internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred in the fourth quarter of 2008 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Material Weakness Related to Operating Revenues

Subsequent to the filing of the September 30, 2008 Form 10-Q, the Company identified a material weakness in our internal control over financial reporting related to the accounting for option premiums on certain derivative instruments. This material weakness resulted from the operational ineffectiveness of reconciliation and review controls specifically related to our accounting for premiums on energy options.

The material weakness resulted in an error to operating revenues of $78 million in the third quarter of 2008. In this Form 10-K, we have revised our unaudited quarterly financial data for the quarter ended September 30, 2008. For further information, see Item 15 Note 27, *Unaudited Quarterly Financial Data,* to the Consolidated Financial Statements.

In connection with this material weakness, we reevaluated our disclosure controls and procedures as of September 30, 2008. Based on this reevaluation, and solely as a result of this material weakness, the Company s principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were not effective as of September 30, 2008.

Remediation of Material Weakness in Internal Control

During the fourth quarter, a number of remedial actions were taken to address the material weakness, which included:

- Reviewing and documenting all mark-to-market logic in our power marketing trading activity system, including any manual adjustments related thereto;
- Formalizing and documenting energy options accounting;
- Formalizing the analysis and review by management of realized and unrealized gain/(loss) derivative accounts;
- Expanding the communication process between accounting, risk management and commercial operations groups to understand derivative accounting results and changes in the commercial operations portfolio; and
- Establishing ongoing training and education in the Company s accounting group on accounting for derivative option premiums

We have completed the process of implementing the aforementioned enhancements, and believe that we have fully remediated the material weakness in our internal control over financial reporting with respect to the appropriate accounting for option premiums on certain derivative instruments as of December 31, 2008.

Inherent Limitations over Internal Controls

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

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
2. Provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
3. Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

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

Item 9B ***Other Information***

None.

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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 2009 Annual Meeting of Stockholders.

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 2009 Annual Meeting of Stockholders.

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 2009 Annual Meeting of Stockholders.

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 2009 Annual Meeting of Stockholders.

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 2009 Annual Meeting of Stockholders.

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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, 2008, 2007 and 2006

Consolidated Balance Sheet December 31, 2008 and 2007

Consolidated Statement of Cash Flows Years ended December 31, 2008, 2007 and 2006

Consolidated Statement of Stockholders Equity and Comprehensive Income/(Loss) Years ended December 31, 2008, 2007 and 2006

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, 2008.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2008 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, 2008, 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, 2008, 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. and subsidiaries as of December 31, 2008 and 2007, 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, 2008, and our report dated February 12, 2009 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 12, 2009

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, 2008 and 2007, and the related consolidated statements of operations, consolidated statement of stockholders equity and comprehensive income/(loss), and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, 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, in order to comply with the requirements of U.S. generally accepted accounting principles, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements, effective January 1, 2008; FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of SFAS No. 109, effective January 1, 2007; Emerging Issues Task Force Issue No. 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry, and SFAS No. 123R, Share Based Payments, and related interpretations effective January 1, 2006; and SFAS No 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of SFAS No. 87, 88, 106 and 132R, effective December 31, 2006.

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, 2008, 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 12, 2009 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 12, 2009

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2008	2007	2006
	(In millions except per share amounts)		
Operating Revenues			
Total operating revenues	$ 6,885	$ 5,989	$ 5,585
Operating Costs and Expenses			
Cost of operations	3,598	3,378	3,265
Depreciation and amortization	649	658	590
General and administrative	319	309	276
Development costs	46	101	36
Total operating costs and expenses	4,612	4,446	4,167
Gain on sale of assets		17	
Operating Income	2,273	1,560	1,418
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	59	54	60
Gains on sales of equity method investments		1	8
Other income, net	17	55	156
Refinancing expenses		(35)	(187)
Interest expense	(620)	(689)	(590)
Total other expenses	(544)	(614)	(553)
Income From Continuing Operations Before Income Taxes	1,729	946	865
Income tax expense	713	377	322
Income From Continuing Operations	1,016	569	543
Income from discontinued operations, net of income taxes	172	17	78
Net Income	1,188	586	621
Dividends for preferred shares	55	55	50
Income Available for Common Stockholders	$ 1,133	$ 531	$ 571
Weighted average number of common shares outstanding basic	235	240	258
Income from continuing operations per weighted average common share basic	$ 4.09	$ 2.14	$ 1.90
Income from discontinued operations per weighted average common share basic	0.73	0.07	0.31

Net Income per Weighted Average Common Share Basic	$	4.82	$	2.21	$	2.21
Weighted average number of common shares outstanding diluted		275		288		301
Income from continuing operations per weighted average common share diluted	$	3.66	$	1.95	$	1.78
Income from discontinued operations per weighted average common share diluted		0.63		0.06		0.26
Net Income per Weighted Average Common Share Diluted	$	4.29	$	2.01	$	2.04

See notes to Consolidated Financial Statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2008	As of December 31, 2007
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,494	$ 1,132
Funds deposited by counterparties	754	
Restricted cash	16	29
Accounts receivable trade, less allowance for doubtful accounts of $3 and $1	464	482
Current portion of note receivable affiliate and capital leases	68	30
Inventory	455	451
Derivative instruments valuation	4,600	1,034
Deferred income taxes		124
Cash collateral paid in support of energy risk management activities	494	85
Prepayments and other current assets	147	144
Current assets discontinued operations		51
Total current assets	8,492	3,562
Property, Plant and Equipment		
In service	13,084	12,678
Under construction	804	337
Total property, plant and equipment	13,888	13,015
Less accumulated depreciation	(2,343)	(1,695)
Net property, plant and equipment	11,545	11,320
Other Assets		
Equity investments in affiliates	490	425
Capital leases and note receivable, less current portion	435	491
Goodwill	1,718	1,786
Intangible assets, net of accumulated amortization of $335 and $372	815	873
Nuclear decommissioning trust fund	303	384
Derivative instruments valuation	885	150
Other non-current assets	125	190
Non-current assets discontinued operations		93
Total other assets	4,771	4,392
Total Assets	$ 24,808	$ 19,274

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	As of December 31, 2008	2007
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 464	$ 466
Accounts payable trade	447	381
Accounts payable affiliates	4	3
Derivative instruments valuation	3,981	917
Deferred income taxes	201	
Cash collateral received in support of energy risk management activities	760	14
Accrued interest expense	178	185
Other accrued expenses	215	189
Other current liabilities	331	85
Current liabilities discontinued operations		37
Total current liabilities	6,581	2,277
Other Liabilities		
Long-term debt and capital leases	7,704	7,895
Nuclear decommissioning reserve	284	307
Nuclear decommissioning trust liability	218	326
Postretirement and other benefit obligations	277	263
Deferred income taxes	1,190	843
Derivative instruments valuation	508	759
Out-of-market contracts	291	628
Other non-current liabilities	392	149
Non-current liabilities discontinued operations		76
Total non-current liabilities	10,864	11,246
Total Liabilities	17,445	13,523
Minority Interest	7	
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
	447	486

5.75% convertible perpetual preferred stock; $0.01 par value, 1,841,680 shares issued and outstanding at December 31, 2008, (at liquidation value of $462, net of issuance costs) and 2,000,000 shares issued and outstanding at December 31, 2007 (at liquidation value of $500, net of issuance costs)		
Common Stock; $0.01 par value; 500,000,000 shares authorized; 263,599,200 and 261,285,529 shares issued and 234,356,717 and 236,734,929 shares outstanding at December 31, 2008 and 2007	3	3
Additional paid-in-capital	4,363	4,092
Retained earnings	2,403	1,270
Less treasury stock, at cost 29,242,483 and 24,550,600 shares at December 31, 2008 and 2007	(823)	(638)
Accumulated other comprehensive income/(loss)	310	(115)
Total Stockholders Equity	7,109	5,504
Total Liabilities and Stockholders Equity	$ 24,808	$ 19,274

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	Shares	Common Stock	Shares	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholde Equity
					(In millions)				
ances at December 31, 05	$ 406	0.4	$ 3	161	$ 2,429	$ 261	$ (663)	$ (205)	$ 2,23
income						621			62
eign currency translation ustments								60	6
realized gain on ivatives, net of $135 tax								405	40
nimum pension liability, of $3 tax								7	
mprehensive income for 06									1,09
act upon adoption of AS 158, net of $10 tax								15	1
duction to tax valuation owance					17				1
act upon adoption of TF 04-6						(93)			(9
uity-based compensation					14				1
uance of common stock he public				42	986				98
uance of preferred stock	486	2.0							48
uance of common and asury stock to the reholders of Texas nco				71	1,028		663		1,69
ferred stock dividends						(50)			(5
chase of treasury stock				(29)			(732)		(73
ances at December 31, 06	892	2.4	3	245	4,474	739	(732)	282	5,65
income						586			58
eign currency translation ustments								73	7
realized loss on ivatives, net of $310 tax								(474)	(47

efit									
ailable-for-sale urities, net of $1 tax								2	
fined benefit plan prior vice cost of $4 and net s of $2, net of $2 tax								2	
mprehensive income for 07									18
uity-based compensation				1	9				
duction to tax valuation owance					56				5
ferred stock dividends						(55)			(5
chase of treasury stock				(9)			(353)		(35
irement of treasury stock					(447)		447		
ances at December 31, 07	892	2.4	3	237	4,092	1,270	(638)	(115)	5,50
income						1,188			1,18
eign currency translation ustments, net of $22 tax								(112)	(11
classification adjustment translation loss realized on sale of ITISA								15	1
realized gain on ivatives, net of $369 tax								580	58
ailable-for-sale urities, net of $2 tax efit								(4)	(
fined benefit plan prior vice credit of $1 and net s of $55, net of $35 tax efit								(54)	(5
mprehensive income for 08									1,61
uity-based compensation				1	25				2
chase of treasury stock				(5)			(185)		(18
duction to tax valuation owance					162				16
ferred stock dividends						(55)			(5
NA contribution, net of 7 tax					26				2
5% preferred stock version to common ck	(39)	(0.1)		1	39				
her					19				1
ances at December 31, 08	$ 853	2.3	$ 3	234	$ 4,363	$ 2,403	$ (823)	$ 310	$ 7,10

See notes to Consolidated Financial Statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008	2007	2006
	(In millions)		
Cash Flows from Operating Activities			
Net income	$ 1,188	$ 586	$ 621
Adjustments to reconcile net income to net cash provided by operating activities			
Distributions less than equity in earnings of unconsolidated affiliates	(44)	(33)	(33)
Depreciation and amortization	649	661	607
Amortization of nuclear fuel	39	58	47
Amortization and write-off of financing costs and debt discount/premiums	29	66	79
Amortization of intangibles and out-of-market contracts	(270)	(156)	(490)
Amortization of unearned equity compensation	26	19	14
Gains on sale of equity method investments		(1)	(8)
Loss/(gain) on disposals and sales of assets	25	(17)	10
Impairment charges and asset write downs	23	20	
Changes in derivatives	(484)	77	(149)
Changes in deferred income taxes and liability for unrecognized tax benefits	762	359	327
Gain on legal settlement			(67)
Gain on sale of discontinued operations	(273)		(76)
Gain on sale of emission allowances	(51)	(31)	(64)
Change in nuclear decommissioning trust liability	34	32	12
Changes in collateral deposits supporting energy risk management activities	(417)	(125)	454
Settlement of out-of-market power contracts			(1,073)
Cash provided/(used) by changes in other working capital, net of acquisition and disposition effects			
Accounts receivable, net	1	(102)	87
Inventory	(5)	(38)	(50)
Prepayments and other current assets	(7)	22	43
Accounts payable	(31)	49	(73)
Accrued expenses and other current liabilities	262	106	133
Other assets and liabilities	(22)	(35)	57
Net Cash Provided by Operating Activities	1,434	1,517	408
Cash Flows from Investing Activities			
Acquisition of Texas Genco, WCP and Padoma, net of cash acquired			(4,333)
Capital expenditures	(899)	(481)	(221)
Decrease in restricted cash, net	13	12	6
Decrease in notes receivable	10	34	27
Decrease in trust fund balances		19	

Purchases of emission allowances	(8)	(161)	(135)
Proceeds from sale of emission allowances	75	272	146
Investments in nuclear decommissioning trust fund securities	(616)	(265)	(227)
Proceeds from sales of nuclear decommissioning trust fund securities	582	233	214
Proceeds from sale of assets	14	2	86
Equity investment in unconsolidated affiliate	(84)		
Purchases of securities		(49)	
Proceeds from sale of discontinued operations and assets, net of cash divested	241	57	260
Return of capital from equity method investments			1
Net Cash Used by Investing Activities	(672)	(327)	(4,176)
Cash Flows from Financing Activities			
Payment of dividends to preferred stockholders	(55)	(55)	(50)
Payment of financing element of acquired derivatives	(43)		(296)
Payment for treasury stock	(185)	(353)	(732)
Proceeds from sale of minority interest in subsidiary	50		
Funded letter of credit			350
Proceeds from issuance of common stock, net of issuance costs	9	7	986
Proceeds from issuance of preferred shares, net of issuance costs			486
Proceeds from issuance of long-term debt	20	1,411	8,619
Payment of deferred debt issuance costs	(4)	(5)	(199)
Payments for short and long-term debt	(234)	(1,819)	(5,111)
Net Cash Provided/(Used) by Financing Activities	(442)	(814)	4,053
Change in cash from discontinued operations	43	(25)	2
Effect of exchange rate changes on cash and cash equivalents	(1)	4	4
Net Increase in Cash and Cash Equivalents	362	355	291
Cash and Cash Equivalents at Beginning of Period	1,132	777	486
Cash and Cash Equivalents at End of Period	$ 1,494	$ 1,132	$ 777

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., or NRG or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the US. 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 US and select international markets.

As of December 31, 2008, NRG had a total global portfolio of 189 active operating fossil fuel and nuclear generation units, at 48 power generation plants, with an aggregate generation capacity of approximately 24,005 MW, and approximately 550 MW under construction which includes partners interests of 275 MW. In addition, NRG has ownership interests in two wind farms representing an aggregate generation capacity of 270 MW, which includes partner interests of 75 MW. Within the US, NRG has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,925 MW of fossil fuel and nuclear generation capacity in 177 active generating units at 43 plants and ownership interests in two wind farms representing 195 MW of wind generation capacity. These power generation facilities are primarily located in Texas (approximately 11,010 MW, including the 195 MW from the two wind farms), the Northeast (approximately 7,020 MW), South Central (approximately 2,845 MW), and West (approximately 2,130 MW) regions of the US, and 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, or FIN, No. 46R, *Consolidation of Variable Interest Entities,* or FIN 46R, to consolidate variable interest entities, or VIEs, for which the Company is the primary beneficiary. FIN 46R requires a variable interest holder to consolidate a VIE if that party will absorb a majority of the expected losses of the VIE, receive the majority of the expected residual returns of the VIE, or both. This party is considered the primary beneficiary. Conversely, NRG will not consolidate a VIE in which it has a majority ownership interest when the Company is not considered the primary beneficiary. In determining the primary beneficiary, NRG thoroughly evaluates the VIE s design, capital structure, and relationships among variable interest holders. If a primary beneficiary cannot be determined by a qualitative analysis, a quantitative analysis 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 has investments in partnerships, joint ventures and projects, one of which is a VIE for which the Company is not the primary beneficiary.

Accounting policies for all of NRG s operations are in accordance with accounting principles generally accepted in the US. Upon its emergence from bankruptcy on December 5, 2003, the Company qualified for and

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adopted fresh start reporting, or Fresh Start, under Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*.

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.

Funds Deposited by Counterparties

Funds deposited by counterparties consist of cash held as collateral from hedge counterparties in support of energy risk management activities, and at December 31, 2008, it is the Company s intention to limit the use of these funds. Depending on market fluctuations and the settlement of the underlying contracts, the Company will refund this collateral to the hedge counterparties pursuant to the terms and conditions of the underlying trades. No such restrictions were imposed by the Company in prior periods, and the amount of cash collateral held at December 31, 2007 was immaterial. Changes in funds deposited by counterparties are closely associated with the Company s operating activities, and are classified as an operating activity in the Company s consolidated statements of cash flows.

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.

Trade Receivables

Trade receivables are reported in the balance sheet at outstanding principal adjusted for any write-offs and the allowance for doubtful accounts.

Inventory

Inventory is valued at the lower of weighted average cost or market, unless evidence indicates that the weighted average cost will be recovered with a normal profit in the ordinary course of business, and consists principally of fuel oil, coal and raw materials used to generate steam. The Company removes these inventories as they are used in the production of electricity or 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. The Company removes these inventories when they are used for repairs, maintenance or capital projects. 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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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 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 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

Project 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.

Interest incurred on funds borrowed to finance capital projects is capitalized if material, until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2008, 2007 and 2006 was $45 million, $11 million and $5 million, respectively.

When a project is available for operations, capitalized interest and project development 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.

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 a contracted volumes, straight line or units of production basis.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008.

Goodwill

In accordance with 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.

Income Taxes

NRG accounts for income taxes using the liability method in accordance with 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 assets to an amount that is more-likely-than-not to be realized.

In January 2007, the Company adopted FIN No. 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. Under FIN 48, tax benefits are recognized 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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 Emerging Issues Task Force, or 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 billed to 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 revenue in the Company s consolidated statements of operations.

Contract Amortization Liabilities recognized from power sales agreements assumed at Fresh Start and through acquisitions related to the sale of electric capacity and energy in future periods for which the fair value has been determined to be significantly less than market is amortized as an increase to revenue over the term of each underlying contract based on actual generation and/or contracted volumes.

Derivative Financial Instruments

NRG accounts for derivative financial instruments under SFAS 133. SFAS 133 requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a 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 OCI until the hedged transactions occur and are recognized in earnings.

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. In this case, the gain or loss previously deferred in OCI would be immediately reclassified into earnings. If the derivative instrument is terminated, the effective portion of this derivative in OCI will be frozen until the underlying hedged item is delivered.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenues and expenses on contracts that qualify for the NPNS exception are recognized when the underlying physical transaction is delivered. 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 that profit from market price changes as opposed to hedging an exposure, and are subject to limits in accordance with the Company s risk management policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings. These trading activities are a complement to NRG s energy marketing portfolio.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG s foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of the Company s statements of operations for the period, but are accumulated and reported as a separate component of stockholders equity until sale or complete or substantially complete liquidation of the net investment in the foreign entity takes place. 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, 2008, 2007 and 2006, 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, derivatives, and investments in debt securities. Cash and cash equivalents and funds deposited by counterparties are predominantly held in money market funds invested in treasury securities or treasury repurchase agreements. 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 and other contractual arrangements are subject to collateral requirements under the terms of enabling agreements. However, NRG believes that the credit risk posed by industry concentration is offset by the diversification and creditworthiness of the Company s customer base. See Note 5, *Accounting for Derivative Instruments and Hedging Activities,* for a further discussion of derivative concentrations.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, funds deposited by counterparties, 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, *Fair Value of 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. For the years ended December 31, 2008 and 2007, the Company recorded impairment charges related to an investment in commercial paper of $23 million and $11 million, respectively; reducing its carrying value to approximately $7 million.

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Retirement Obligations

NRG accounts for its asset retirement obligations, or AROs, in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, or SFAS 143, and FIN No. 47, *Accounting for Conditional Asset Retirement Obligations*, or FIN 47. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 and FIN 47 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. SFAS 143 and FIN 47 require an entity to recognize the fair value of a liability for an ARO in the period in which it is incurred and a reasonable estimate of fair value can be made.

Upon initial recognition of a liability for an ARO, NRG capitalizes the asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount. Over time, the liability is accreted to its future value, while the capitalized cost is depreciated over the useful life of the related asset.

NRG s AROs are primarily related to the future dismantlement of equipment on leased property and environmental obligations related to nuclear decommissioning, ash disposal, site closures, and fuel storage facilities. In addition, NRG has also identified conditional AROs for asbestos removal and disposal, which are specific to certain power generation operations. See Note 6, *Nuclear Decommissioning Trust Fund,* for a further discussion of NRG s nuclear decommissioning obligations.

The following table represents the balance of ARO obligations as of December 31, 2008 and 2007, along with the additions, reductions and accretion related to the Company s ARO obligations for the year ended December 31, 2008:

	Total (In millions)
Balance as of December 31, 2007	$ 409
Additions	1
Revisions in estimated cashflows	(41)
Accretion Expense	7
Accretion Other	17
Balance as of December 31, 2008	$ 393

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.

As of December 31, 2008, NRG measured the fair value of its pension assets in accordance with SFAS 157, *Fair Value Measurements*.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Stock-Based Compensation

NRG accounts for its stock-based compensation in accordance with SFAS No. 123 (Revised 2004), *Share-Based Payment*, or SFAS 123R. 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 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. 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.

Issuance of Subsidiary s Stock

The Company accounts for issuance of its subsidiaries stock in accordance with SEC Staff Accounting Bulletin Topic 5H, *Accounting For Sales Of Stock By A Subsidiary*, or Topic 5H. Topic 5H precludes recognizing any gain on issuance of a subsidiary s stock into earnings when the subsidiary is a development stage entity. In March 2008, NRG formed NINA, an NRG development stage subsidiary focused on developing, financing, and investing in nuclear projects in North America. TANE has partnered with NRG on the NINA venture, receiving a 12% equity ownership in NINA in exchange for $300 million to be invested in NINA in six annual installments of $50 million, the last three of which are subject to certain restrictions. NRG continues to control NINA through its voting interest. Any change in NRG s proportionate share of NINA s equity resulting from cash invested by TANE directly into NINA is accounted for by the Company as an equity transaction in consolidation, and not a gain on sale, for as long as NINA remains a development stage entity.

Accordingly, upon TANE s initial $50 million installment contribution in April 2008, $44 million, or 88%, was recorded as additional paid in capital, while the remaining $6 million, or 12%, was recorded as minority interest on the Company s consolidated balance sheet.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the US 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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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 and goodwill 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.

Recent Accounting Developments

The Company partially adopted SFAS No. 157, *Fair Value Measurements*, or SFAS 157, on January 1, 2008, delaying application for non-financial assets and non-financial liabilities as permitted. This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. 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 SFAS 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 non-financial assets and non-financial 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. The partial adoption of SFAS 157 on January 1, 2008 did not have a material impact on the Company s consolidated financial position, statement of operations, and cash flows. The Company adopted the remaining portion of SFAS 157 for non-financial assets and non-financial liabilities on January 1, 2009, with no impact on the Company s consolidated financial position, statement of operations, and cash flows.

The Company adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities-including an amendment of FASB Statement No. 115,* or SFAS 159, on January 1, 2008. This statement provides entities with an option to measure and report selected financial assets and liabilities at fair value. The Company does not intend to apply this standard to any of its eligible assets or liabilities; therefore, there was no impact on NRG s consolidated financial position, results of operations, or cash flows.

The Company adopted FSP 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*, on January 1, 2008. FSP FIN 39-1 impacts entities that enter into master netting arrangements as part of their derivative transactions. Under the guidance in this 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. The Company chose not to offset positions as defined in this FSP; 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 141R. 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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 adopted SFAS 141R on January 1, 2009, with no immediate impact on the Company s results of operations, financial position and cash flows. However, any future reductions to existing net deferred tax assets or valuation allowances, and changes to uncertain tax benefits, as they relate to Fresh Start or previously completed acquisitions, occurring after January 1, 2009 will be recorded to income tax expense rather than APIC or goodwill, respectively.

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 141R. 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 adopted SFAS 160 on January 1, 2009, with no material impact on the Company s consolidated financial position, statement of operations, and cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities*, or SFAS 161. SFAS 161 requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. NRG adopted SFAS 161 on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets,* or FSP FAS 142-3. This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, with early adoption prohibited. NRG adopted FSP FAS 142-3 on January 1, 2009, with no impact on the Company s results of operations, financial position and cash flows.

In May 2008, the FASB issued FSP No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement),* or FSP APB 14-1. This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) do not fall within the scope of paragraph 12 of Accounting Principles Board Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants,* and specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. FSP APB 14-1 does not apply to embedded conversion options that must be separately accounted for as derivatives under SFAS 133. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years and is to be applied retrospectively. NRG adopted FSP APB 14-1 on January 1, 2009, with no material impact on the Company s results of operations, financial position, or cash flows.

In June 2008, the EITF issued EITF No. 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock,* or EITF 07-5. EITF 07-5 clarifies that contingent and other adjustment features in equity-linked financial instruments are consistent with equity indexation if they are based on variables that would be inputs to a plain vanilla option or forward pricing model and they do not increase the contract s exposure to those variables. EITF 07-5 is effective for financial statements issued for fiscal years beginning after December 15,

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2008, and interim periods within those fiscal years. NRG adopted EITF 07-5 on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows.

In September 2008, the FASB issued FSP No. FAS 133-1 and FIN 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and Financial Interpretation Number 45; and Clarification of the Effective Date of FASB Statement No. 161*, or FSP FAS 133-1 and FIN 45-4. This FSP amends FAS 133, and FIN No. 45 *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others,* or FIN 45, to require additional disclosures about credit derivatives, credit derivatives embedded in a hybrid instrument, and the current status of the payment or performance risk of a guarantee. FSP FAS 133-1 and FIN 45-4 is effective for the financial statements of reporting periods (annual or interim) ending after November 15, 2008. NRG currently has no credit derivative contracts, so the amendments in this FSP related to FAS 133 will not impact NRG. The clarification to SFAS 161 is also not applicable to NRG, as it only affects non-calendar year filers. NRG adopted the provisions of this FSP related to FIN 45 on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows.

In September 2008, the EITF issued EITF 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement,* or EITF 08-5. EITF 08-5 requires issuers of liability instruments with third-party credit enhancements to exclude the effect of the credit enhancement when measuring the liability s fair value. The effect of initially applying the requirements is included in the change in the instrument s fair value in the period of adoption. Entities are required to disclose the valuation technique used to measure the liabilities and to discuss any changes in the valuation techniques used to measure those liabilities in earlier periods. Entities will also need to disclose the existence of a third-party credit enhancement on the entity s issued debt. EITF 08-5 is effective on a prospective basis in the first reporting period beginning on or after December 15, 2008, with earlier application permitted. NRG adopted EITF 08-5 on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows.

In October 2008, the FASB issued FSP No. FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,* or FSP FAS 157-3. This FSP clarifies the application of SFAS 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 is effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate under SFAS No. 154, *Accounting Changes and Error Corrections,* or SFAS 154. The disclosure provisions of SFAS 154 for a change in accounting estimate are not required for revisions resulting from a change in valuation technique or its application. Although effective for the year ended December 31, 2008, FSP FAS 157-3 did not have an impact on the Company s results of operations, financial position, or cash flows.

In November 2008, the EITF issued EITF 08-6, *Equity Method Investment Accounting Considerations*, or EITF 08-6. EITF 08-6 addresses questions about the potential effect of FAS 141R and FAS 160 on equity-method accounting under APB 18. EITF 08-6 generally continues existing practices under APB 18, including the use of a cost-accumulation approach to initial measurement of the investment. This EITF does not require the investor to perform a separate impairment test on the underlying assets of an equity method investment. However, an equity-method investor is required to recognize its proportionate share of impairment charges recognized by the investee, adjusted for basis differences, if any, between the investee s carrying amount for the impaired assets and the cost allocated to such assets by the investor. The investor is also required to perform an overall other-than-temporary impairment test of its investment in accordance with APB 18. EITF 08-6 is effective for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years, and shall be applied prospectively. Early application is not permitted. The Company adopted EITF 08-6 on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows.

In December 2008, the FASB issued FSP No. FAS 140-4 and FIN 46(R)-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial assets and Interests in Variable Interest Entities, or* FSP FAS 140-4 and

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

FIN 46R-8. This FSP amends FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* to require public entities to provide additional disclosures about transfers of financial assets. It also amends FIN 46R to require public enterprises, including sponsors that have a variable interest in a VIE, to provide additional disclosures about their involvement with such VIEs. FSP FAS 140-4 and FIN 46R-8 is effective immediately. NRG does not engage in transfers of financial assets within the scope of FAS 140, so the amendments in this FSP related to FAS 140 will not impact NRG. The additional disclosure requirements related to FIN 46R have been adopted by NRG and included in the December 31, 2008 financial statements, with no impact on the Company s results of operations, financial position, or cash flows.

In December 2008, the FASB also issued FSP No. FAS 132(R)-1 *Employers Disclosures about Postretirement Benefit Plan Assets,* or FSP 132R-1. This FSP amends FASB Statement No. 132 (revised 2003), *Employers Disclosures about Pensions and Other Postretirement Benefits,* to provide guidance and additional transparency on an employer s disclosures about plan assets of a defined benefit pension or other postretirement plan, including the concentrations of risk in those plans. The effective date of FSP FAS 132R-1 is for fiscal years beginning after December 15, 2009. The enhanced disclosure requirements are relevant to NRG but will not be effective until the first interim period of 2010, and will not have an impact on the Company s results of operations, financial position, or cash flows.

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
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	

Second Quarter
2008

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2008, there were no assets and liabilities classified as discontinued operations. The following table summarizes the major classes of assets and liabilities classified as discontinued operations as of December 31, 2007.

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

Summarized results of discontinued operations for the years ended December 31, 2008, 2007, and 2006 were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Operating revenues	$ 20	$ 50	$ 227
Operating costs and other expenses	9	27	224

Pre-tax income from operations of discontinued components		11		23		3
Income tax expense		3		6		1
Income from operations of discontinued components		8		17		2
Disposal of discontinued components pre-tax gain		273				80
Income tax expense		109				4
Gain on disposal of discontinued components, net of income taxes		164				76
Income from discontinued operations, net of income taxes	$	172	$	17	$	78

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The pre-tax gain on disposal of the Company s discontinued operations for the years ended December 31, 2008, 2007 and 2006 were as follows:

	Year Ended December 2008	2007	2006	Segment
	(In millions)			
ITISA	$ 273	$	$	International
Resource Recovery			5	Corporate
Flinders			60	International
Audrain			15	Corporate
Total pre-tax gain on disposal of discontinued operations	$ 273	$	$ 80	

ITISA The assets and liabilities reported in the balance sheet as of December 31, 2007 as discontinued operations represent those of ITISA. On April 28, 2008, NRG completed the sale of its 100% interest in Tosli, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 consolidated balance sheet.

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.

Acquisition of Texas Genco LLC, or Texas Genco

On February 2, 2006, NRG acquired Texas Genco, 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 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 $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 debt.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The acquisition of Texas Genco 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; and (v) cash on hand.

The acquisition of Texas Genco 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 $1,782 million and was recorded as goodwill.

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 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.

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.

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NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4 Fair Value of Financial Instruments

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

	Year Ended December 31,			
	Carrying Amount		Fair Value	
	2008	2007	2008	2007
	(In millions)			
Cash and cash equivalents	$ 1,494	$ 1,132	$ 1,494	$ 1,132
Funds deposited by counterparties	754		754	
Restricted cash	16	29	16	29
Cash collateral paid in support of energy risk management activities	494	85	494	85
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	7	32	7	32
Marketable equity securities	2	7	2	7
Trust fund investments	305	390	305	390
Notes receivable	156	126	166	138
Derivative assets	5,485	1,184	5,485	1,184
Long-term debt, including current portion	8,026	8,180	7,496	8,164
Cash collateral received in support of energy risk management activities	760	14	760	14
Derivative liabilities	4,489	1,676	4,489	1,676

For cash and cash equivalents, funds deposited by counterparties, restricted cash, and cash collateral paid and received in support of energy risk management activities, 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 US 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 long-term debt is based on quoted market prices for these instruments that are publicly traded, or estimated based on the income approach valuation technique for non-publicly traded debt using current interest rates for similar instruments with equivalent credit quality.

Adoption of SFAS No. 157

The Company partially adopted SFAS 157 on January 1, 2008, delaying application for non-financial assets and non-financial liabilities as permitted. This statement establishes a framework for measuring fair value, and expands disclosures about fair value measurements.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access as of the measurement date. NRG s financial assets and liabilities utilizing Level 1 inputs include active exchange-traded securities, energy derivatives, and trust fund investments.

Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. NRG s financial assets and liabilities utilizing Level 2 inputs include fixed income securities, exchange-based derivatives, and over the counter derivatives such as swaps, options and forwards.

Level 3 unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date. NRG s financial assets and liabilities utilizing Level 3 inputs include infrequently-traded, non-exchange-based derivatives and commingled investment funds, and are measured using present value pricing models.

In accordance with SFAS 157, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety.

Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value on the Company s consolidated balance sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2008:

	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
As of December 31, 2008				
Cash and cash equivalents	$ 1,494	$	$	$ 1,494
Funds deposited by counterparties	754			754
Restricted cash	16			16
Cash collateral paid in support of energy risk management activities	494			494
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities			7	7
Marketable equity securities	2			2
Trust fund investments	167	107	31	305
Derivative assets	2,168	3,264	53	5,485

3

(3)
-
Share of after tax profits of associates and joint ventures
26

26

Profit before taxation
3,426
430
104
508
1,706
(124)
6,050

Taxation
(680)
(85)
(15)
(122)
(201)
(77)
(1,180)
Tax rate %
19.8%

19.5%

Profit after taxation
2,746
345
89
386
1,505
(201)
4,870

Profit attributable to non-controlling interests
338

197

535

Profit attributable to shareholders
2,408
345
89
386
1,308
(201)
4,335

Earnings per share
49.0p
7.0p
1.8p
7.9p
26.6p
(4.0)p
88.3p

Weighted average number of shares (millions)
4,911

4,911

Adjusted results exclude the above items from Total results as GSK believes that Adjusted results are more representative of the performance of the Group's operations and allow the key trends and factors driving performance to be more easily and clearly identified by shareholders. For a fuller explanation of Adjusted results, see 'Reporting definitions' on page 37.

Income statement – Adjusted results reconciliation
Nine months ended 30 September 2017

	Total results £m	Intangible amort-isation £m	Intangible impair-ment £m	Major restruct-uring £m	Transaction-related £m	Divestments, significant legal and other items £m	Adjusted results £m
Turnover	22,547						22,547
Cost of sales	(7,784)	410	334	466	61		(6,513)
Gross profit	14,763	410	334	466	61		16,034
Selling, general and administration	(7,139)			152		66	(6,921)
Research and development	(3,267)	34	87	253		23	(2,870)
Royalty income	287						287
Other operating income/(expense)	(1,069)			1	1,297	(229)	-
Operating profit	3,575	444	421	872	1,358	(140)	6,530
Net finance costs	(531)			3		6	(522)
Profit on disposal of associates	28					(28)	-
Share of after tax profits of associates and joint ventures	11						11
Profit before taxation	3,083	444	421	875	1,358	(162)	6,019
Taxation	(551)	(100)	(125)	(249)	(152)	(109)	(1,286)
Tax rate %	17.9%						21.4%

Profit after taxation	2,532	344	296	626	1,206	(271)	4,733
Profit attributable to non-controlling interests	454				147		601
Profit attributable to shareholders	2,078	344	296	626	1,059	(271)	4,132
Earnings per share	42.5p	7.1p	6.1p	12.8p	21.7p	(5.6)p	84.6p
Weighted average number of shares (millions)	4,884						4,884

Adjusted results exclude the above items from Total results as GSK believes that Adjusted results are more representative of the performance of the Group's operations and allow the key trends and factors driving performance to be more easily and clearly identified by shareholders. For a fuller explanation of Adjusted results, see 'Reporting definitions' on page 37.

Independent review report to GlaxoSmithKline plc

We have been engaged by GlaxoSmithKline plc ("the Company") to review the condensed financial information in the Results Announcement for the three and nine months ended 30 September 2018.

What we have reviewed
The condensed financial information comprises:

- the income statement and statement of comprehensive income for the three and nine month periods ended 30 September 2018 on pages 40 and 41 to 42 respectively;
- the balance sheet as at 30 September 2018 on page 46;
- the statement of changes in equity for the nine month period then ended on page 47;
- the cash flow statement for the nine month period then ended on page 48 and;
- the accounting policies and basis of preparation and the explanatory notes to the condensed financial information on pages 49 to 57 that have been prepared applying consistent accounting policies to those applied by the Group in the Annual Report 2017, which was prepared in accordance with International Financial Reporting Standards ("IFRS") as adopted by the European Union, except for the implementation of IFRS 15 "Revenue from Contracts with Customers" and IFRS 9 "Financial Instruments" from 1 January 2018.

We have read the other information contained in the Results Announcement, including the non-IFRS measures contained on pages 49 to 57, and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed financial statements.

This report is made solely to the Company in accordance with International Standard on Review Engagements (UK and Ireland) 2410 "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board. Our work has been undertaken so that we might state to the Company those matters we are required to state to it in an independent review report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company, for our review work, for this report, or for the conclusions we have formed.

Directors' responsibilities
The Results Announcement of GlaxoSmithKline plc, including the condensed financial information, is the responsibility of, and has been approved by, the directors. The directors are responsible for preparing the Results Announcement by applying consistent accounting policies to those applied by the Group in the Annual Report 2017, which was prepared in accordance with IFRS as adopted by the European Union, except for the implementation of IFRS 15 "Revenue from Contracts with Customers" and IFRS 9 "Financial Instruments" from 1 January 2018.

Our responsibility
Our responsibility is to express to the Company a conclusion on the interim financial information in the Results Announcement based on our review.

Scope of review
We conducted our review in accordance with International Standard on Review Engagements (UK and Ireland) 2410 "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board for use in the United Kingdom. A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion
Based on our review, nothing has come to our attention that causes us to believe that the condensed interim financial information in the Results Announcement for the three and nine months ended 30 September 2018 are not prepared, in all material respects, in accordance with the accounting policies set out in the accounting policies and basis of preparation section on page 52.

Deloitte LLP
Statutory Auditor
London, United Kingdom
31 October 2018

SIGNATURES

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

GlaxoSmithKline plc
(Registrant)

Date: October 31, 2018

By: VICTORIA WHYTE

Victoria Whyte
Authorised Signatory for and on
behalf of GlaxoSmithKline plc