NRG ENERGY, INC.
Form 10-K
February 23, 2010

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, 2009.

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

Commission file No. 001-15891
NRG Energy, Inc.
(Exact name of registrant as specified in its charter)

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

(609) 524-4500
(Registrant s telephone number, including area code:)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Exchange on Which Registered**
Common Stock, par value $0.01	New York Stock Exchange

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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. þ

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 (Do not check if a smaller reporting company)   Smaller reporting company o

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

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $6,803,812,501 based on the closing sale price of $25.96 as reported on the New York Stock Exchange.

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 17, 2010**
Common Stock, par value $0.01 per share	261,898,178

Documents Incorporated by Reference:

Portions of the Proxy Statement for the 2010 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K

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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
APB	Accounting Principles Board
ARO	Asset Retirement Obligation
ASC	The FASB Accounting Standards Codification, which the FASB has established as the source of authoritative U.S. GAAP
ASU	Accounting Standards Updates updates to the ASC
Baseload capacity	Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAA	Clean Air Act
CAGR	Compound annual growth rate
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
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
C&I	Commercial, industrial and governmental/institutional
CL&P	The Connecticut Light & Power Company
CO_2	Carbon dioxide
COLA	Combined Construction and Operating License Application
CPS	CPS Energy
CS	Credit Suisse Group
CSF I	NRG Common Stock Finance I LLC
CSF II	NRG Common Stock Finance II LLC
CSF CAGRs	Embedded derivatives within the CSF Debt, individually referred to as CSF I CAGR and CSF II CAGR
CSF Debt	CSF I and CSF II issued notes and preferred interest, individually referred to as CSF I Debt and CSF II Debt
CSRA	Credit Sleeve Reimbursement Agreement with Merrill Lynch in connection with acquisition of Reliant Energy, as hereinafter defined
CSRA Amendment	Amendment of the existing CSRA with Merrill Lynch which became effective October 5, 2009
DNREC	Delaware Department of Natural Resources and Environmental Control
DOE	Department of Energy
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
EITF	Emerging Issues Task Force

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
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
FPA	Federal Power Act
Fresh Start	Reporting requirements as defined by ASC-852, *Reorganizations*
FSP	FASB Staff Position
GHG	Greenhouse Gases
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
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
MACT	Maximum Achievable Control Technology
Mass	Residential and small business
Merit Order	A term used for the ranking of power stations in order of ascending marginal cost
MIBRAG	Mitteldeutsche Braunkohlengesellschaft mbH
MMBtu	Million British Thermal Units
MRTU	Market Redesign and Technology Upgrade
MVA	Megavolt-ampere
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, 2009
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.

NINA	Nuclear Innovation North America LLC
NO_x	Nitrogen oxide
NOL	Net Operating Loss
NOV	Notice of Violation
NPNS	Normal Purchase Normal Sale
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
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
PML	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
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
QF	Qualifying Facility under PURPA
Reliant Energy	NRG s retail business in Texas purchased on May 1, 2009, from Reliant Energy, Inc. which is now known as RRI Energy, Inc., or RRI
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
REPS	Reliant Energy Power Supply, LLC
RERH	RERH Holding, LLC and its subsidiaries
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
RRI	RRI Energy, Inc.
RTO	Regional Transmission Organization, also referred to as an Independent System Operators, or ISO
Sarbanes-Oxley	Sarbanes Oxley Act of 2002, as amended
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
SIFMA	Securities Industry and Financial Markets Association
Senior Notes	The Company s $5.4 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 and $700 million of 8.5% senior notes due 2019
SERC	Southeastern Electric Reliability Council/Entergy

SFAS	Statement of Financial Accounting Standards issued by the FASB
SO_2	Sulfur dioxide
SOP	Statement of Position issued by the American Institute of Certified Public Accountants
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
TANE	Toshiba American Nuclear Operating Company
TANE Facility	NINA s $500 million credit facility with TANE which matures on February 24, 2012
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
TWh	Terawatt hour
U.S.	United States of America
U.S. EPA	United States Environmental Protection Agency
U.S. GAAP	Accounting principles generally accepted in the United States
VaR	Value at Risk
WCP	WCP (Generation) Holdings, Inc.

ACCOUNTING PRONOUNCEMENTS

The following ASC topics are referenced in this report. In addition, certain U.S. GAAP standards and interpretations were adopted by the Company in 2009 prior to the July 1, 2009, effective date of the ASC, and were subsequently incorporated into one or more ASC topics. Further, certain U.S. GAAP standards were ratified by the FASB in 2009 prior to July 1, 2009, but are not yet effective and have therefore not yet been incorporated into the ASC. This glossary includes the definition of these legacy standards and interpretations under the ASC topic or topics in which they have been, or are expected to be, fully or partially incorporated.

ASC 105	ASC-105, *Generally Accepted Accounting Principles*; incorporates: SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*
ASC 270	ASC-270, *Interim Reporting*; incorporates: FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*
ASC 275	ASC-275, *Risks and Uncertainties;* incorporates: FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets*
ASC 320	ASC-320, *Investments-Debt and Equity Securities*; incorporates: FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*
ASC 323	ASC-323, *Investments-Equity Method and Joint Ventures*; incorporates: EITF 08-6, *Equity Method Investment Accounting Considerations* APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*
ASC 350	ASC-350, *Intangibles-Goodwill and Others*; incorporates: FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets* SFAS No. 142, *Goodwill and Other Intangible Assets*
ASC 360	ASC-360, *Property, Plant, and Equipment;* incorporates: SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*
ASC 410	ASC-410, *Asset Retirement and Environmental Obligations;* incorporates: SFAS No. 143, *Accounting for Asset Retirement Obligations*
ASC 450	ASC-450, *Contingencies;* incorporates: SFAS No. 5, *Accounting for Contingencies*
ASC 460	ASC-460, *Guarantees;* incorporates: FIN No. 45, *Guarantor s Accounting and Disclosure Requirements of Guarantees, Including Indirect Guarantees of Indebtedness of Others*
ASC 470	ASC-470, *Debt*; incorporates: FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*
ASC 715	ASC-715, *Compensation-Retirement Benefits;* incorporates: FSP FAS 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets* 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)*
ASC 718	ASC-718, *Compensation-Stock Compensation*; incorporates: EITF 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock*
ASC 740	ASC-740, *Income Taxes*; incorporates: FIN No. 48, *Accounting for Uncertainty in Income Taxes* SFAS No. 109, *Accounting for Income Taxes* APB Opinion No. 23 *Accounting for Income Taxes Special Areas*

ASC 805	ASC-805, *Business Combinations*; incorporates: SFAS 141(R), *Business Combinations* FSP FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies*
ASC 810	ASC-810, *Consolidation*; incorporates: SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, Consolidated Financial Statements*
ASC 815	ASC-815, *Derivatives and Hedging*; incorporates: SFAS 161, *Disclosures About Derivative Instruments and Hedging Activities* EITF 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock* EITF 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*
ASC 820	ASC-820, *Fair Value Measurements and Disclosures*; incorporates: FSP FAS 157-2, *Effective Date of FASB Statement No. 157* FSP FAS 157-4 *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* EITF 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement*
ASC 825	ASC-825, *Financial Instruments*; incorporates: FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)* FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*
ASC 852	ASC-852, *Reorganizations;* incorporates: Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*
ASC 855	ASC-855, *Subsequent Events*; incorporates: SFAS 165, *Subsequent Events*
ASC 980	ASC-980, *Regulated Operations;* incorporates: SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*
ASU 2009-5	ASU 2009-5, *Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value*
ASU 2009-15	ASU 2009-15, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing;* incorporates: EITF 09-1, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing*
ASU 2009-17	ASU No. 2009-17, *Consolidations: Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*; incorporates: SFAS 167, *Amendments to FASB Interpretations No. 46 (R)*
ASU 2010-02	ASU No. 2010-02, *Consolidation (Topic 810): Accounting and Reporting for Decreases in Ownership of a Subsidiary a Scope Clarification*
ASU 2010-06	ASU No. 2010-06, *Fair Value Measurement and Disclosures: Improving Disclosures about Fair Value Measurements*

PART I

Item 1 Business

General

NRG Energy, Inc., or NRG or the Company, is primarily a wholesale power generation company with a significant presence in major competitive power markets in the U.S., as well as a major retail electricity franchise in the Electric Reliability Council of Texas, or ERCOT, market. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, the trading of energy, capacity and related products in the U.S. and select international markets, and the supply of electricity and energy services to retail electricity customers in the Texas market.

As of December 31, 2009, NRG had a total global generation portfolio of 187 active operating fossil fuel and nuclear generation units, at 44 power generation plants, with an aggregate generation capacity of approximately 24,115 MW, and approximately 400 MW under construction which includes partner interests of 200 MW. In addition to its fossil fuel plant ownership, NRG has ownership interests in operating renewable facilities with an aggregate generation capacity of 365 MW, consisting of three wind farms representing an aggregate generation capacity of 345 MW (which includes partner interest of 75 MW) and a solar facility with an aggregate generation capacity of 20 MW. Within the U.S., NRG has large and diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 23,110 MW of fossil fuel and nuclear generation capacity in 179 active generating units at 42 plants. The Company s power generation facilities are most heavily concentrated in Texas (approximately 11,340 MW, including 345 MW from three wind farms), the Northeast (approximately 7,015 MW), South Central (approximately 2,855 MW), and West (approximately 2,150 MW, including 20 MW from a solar farm) regions of the U.S., with approximately 115 MW of additional generation capacity from the Company s thermal assets. In addition, through certain foreign subsidiaries, NRG has investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity.

NRG s principal domestic power plants consist of a mix of natural gas-, coal-, oil-fired, nuclear and renewable facilities, representing approximately 46%, 32%, 16%, 5% and 1% of the Company s total domestic generation capacity, respectively. In addition, 9% 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 the Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s 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.

On May 1, 2009, NRG acquired Reliant Energy, which is the second largest electricity provider to residential and small business, or Mass, customers in Texas. Reliant Energy is also the largest electricity and energy services provider, based on load, to commercial, industrial and governmental/institutions, or C&I, customers in Texas. Based on metered locations, as of December 31, 2009, Reliant Energy had approximately 1.5 million Mass customers and approximately 0.1 million C&I customers. Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service.

Furthermore, 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. These investments include low or no Greenhouse Gas, or GHG, emitting energy generating sources, such as nuclear, wind, solar thermal, photovoltaic, clean coal and gasification, and the retrofit of post-combustion carbon capture technologies.

NRG s Business Strategy

NRG s business strategy is intended to maximize shareholder value through production and the sale of safe, reliable and affordable power to its customers and in the markets served by the Company, while aggressively positioning the Company to meet the market s increasing demand for sustainable and low carbon energy solutions, such as nuclear, renewable, electric vehicle and smart grid services. The Company believes that success in providing energy solutions that address sustainability and climate change concerns will not only reduce the carbon and capital intensity of the Company s financial performance in the future, it also will reduce the real and perceived linkage between the Company s financial performance and prospects, and volatile commodity prices particularly natural gas.

In support of this strategy and NRG s core business strengths, the Company will continue to maintain its focus and execution 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; (iii) empowering retail customers with distinctive products and services that transform how they use, manage and value energy; (iv) engaging in a proactive capital allocation plan focused on achieving the regular return of capital to stockholders within the dictates of prudent balance sheet management; and (v) pursuit of selective acquisitions, joint ventures, divestitures and investments in energy-related new businesses and new technologies in order to enhance the Company s asset mix and competitive position in its core markets, both with respect to its traditional core business and in respect of opportunities associated with the new energy economy.

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 enable the Company to convert the challenges faced by the power industry in the coming years into opportunities for financial growth. 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 2.0 initiative, NRG will continue its companywide effort 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.

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 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 in the execution of asset-based risk management, hedging, marketing and trading strategies within well-defined risk and liquidity guidelines. 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.

The Company also seeks to achieve synergies between the Company s retail and wholesale business in Texas through its complementary generation portfolio in the Texas region, thereby creating the potential for a more stable, reliable and competitive business that benefits Texas consumers. By backing Reliant Energy s load-serving requirements with NRG s generation and risk management practices, the need to sell and buy power from other financial institutions and intermediaries that trade in the ERCOT market may be reduced, resulting in reduced transaction costs, credit exposures, and collateral postings. In addition, with Reliant Energy s base of retail customers, NRG now has a customer interface with the scale that is important to the successful deployment of consumer-facing energy technologies and services.

Finally, NRG remains focused on cash flow and maintaining appropriate levels of liquidity, debt and equity in order to ensure continued access, through all economic and financial cycles, to capital for investment, to enhance risk-adjusted returns and to provide flexibility in executing NRG s business strategy, including a regular return of capital to its debt and equity holders.

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, as well as clean coal and the retrofit of post-combustion carbon capture technologies. Primarily through the *Repowering*NRG and econrg initiatives, 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, with an emphasis on new capacity that is supported by long-term power sales agreements and financed with limited or non-recourse project financing, and the demonstration and deployment of green technologies. *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 in locations where the Company anticipates retiring certain existing units and adding new generation to meet growing demand in the Company s core markets. econrg represents NRG s commitment to environmentally responsible power generation by addressing the challenges of climate change, clean air and water, and conservation of natural resources while taking advantage of business opportunities that may inure to NRG. NRG expects that these efforts will provide some or all of the following benefits: improved heat rates; lower delivered costs; expanded electricity production capability; 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 GHG emissions or can be equipped to capture and sequester GHG emissions. In addition, several of the Company s original *Repowering*NRG projects or projects commenced under that initiative since its inception may qualify for financial support under the infrastructure financing component of the American Recovery and Reinvestment Act as well as other government incentive packages. NRG has several applications pending or contemplated.

New Businesses and New Technology NRG is focused on the development and investment in energy-related new businesses and new technologies, including low or no GHG emitting energy generating sources, such as nuclear, wind, solar thermal, and photovoltaic, as well as other endeavors where the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company, such as smart meters, electric vehicle ecosystems, and distributed clean solutions. The Company has made a series of recent advancements in these initiatives, including: (i) the acquisition of Bluewater Wind, an offshore wind development company; (ii) the acquisition of Blythe Solar, the largest photovoltaic solar power facility in California; (iii) the commercial operation of the Langford Wind Farm, the Company s third wind farm to be brought online; (iv) a partnership between Reliant Energy and the City of Houston and a partnership between Reliant Energy and Nissan to make Houston, Texas a launch city for the use of electric vehicles; and (v) the use of smart meters for Reliant Energy customers. Furthermore, the Company, supported by the econrg initiative, 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.

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 and initiatives. NRG Global Giving is designed to enhance respect for the community, which is one of NRG s core values. The Global Giving Program invests NRG s resources to strengthen the communities where NRG does business and seeks to make community investments in four focus areas: community and economic development, education, environment and human welfare.

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.

The deregulated retail energy business in ERCOT is a competitive business. In general, competition in the retail energy business is on the basis of price, service, brand image, product offerings and market perceptions of creditworthiness. Reliant Energy sells electricity pursuant to fixed price or indexed products, and customers elect terms of service typically ranging from one month to five years. Reliant Energy s rates are market-based rates, and not subject to traditional cost-of-service regulation by the Public Utility Commission of Texas, or PUCT. Non-affiliated transmission and distribution service companies provide, on a non-discriminatory basis, the wires and metering services necessary to access customers.

Competitive Strengths

Scale and diversity of assets NRG has one of the largest and most diversified power generation portfolios in the U.S., with approximately 23,110 MW of fossil fuel and nuclear generation capacity in 179 active generating units at 42 plants and 365 MW renewable generation capacity which consists of ownership interests in three wind farms and a solar facility as of December 31, 2009. 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. As of December 31, 2009, the Company s power generation assets consisted of approximately 10,660 MW of gas-fired; 7,560 MW of coal-fired; 3,715 MW of oil-fired; 1,175 MW of nuclear and 365 MW of renewable generating capacity in the U.S.

NRG has a significant power generation presence in major competitive power markets of the U.S. as set forth in the map below:

(1) Includes 115 MW as part of NRG s Thermal assets. For combined scale, approximately 2,095 MW is dual-fuel capable. Reflects only domestic generation capacity as of December 31, 2009.

The Company s U.S. power generation portfolio by dispatch level is comprised of approximately 37% baseload, 37% intermediate, 25% peaking and 1% intermittent units. NRG s U.S. baseload facilities, which consist of approximately 8,735 MW of generation capacity measured as of December 31, 2009, provide the Company with a significant source of stable cash flow, while its intermediate and peaking facilities, with approximately 14,375 MW of generation capacity as of December 31, 2009, 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 9% 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 2009, NRG completed the construction of the Cedar Bayou Generating Station (520 MW including partner interests of 260 MW) and the Langford wind farm (150 MW), which provide electricity to the Company s core region. In addition, the Company acquired Blythe Solar (20 MW) in November 2009, which provides electricity to the Company s West region.

The following chart demonstrates the diversification of NRG s domestic power generation assets as of December 31, 2009**:**

Approximate North America Portfolio Net Capacity by Fuel Type	**Approximate North America Portfolio Net Capacity by Dispatch Level**	**Approximate North America Portfolio Net Capacity by Region**

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, 2009, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 47% of its expected baseload coal requirement from 2010 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.

With its complementary generation portfolio, the Texas region is a supplier of power to Reliant Energy, thereby creating the potential for more stable, reliable cash flows. By backing Reliant Energy s load-serving requirements with NRG s generation and risk management practices, the need to sell and buy power from other financial institutions and intermediaries that trade in the ERCOT market may be reduced, resulting in lower transaction costs and credit exposures. This combination of generation and retail allows for a reduction in actual and contingent collateral, initially through offsetting transactions and over time by reducing the need to hedge the retail power supply through third parties.

Favorable cost dynamics for baseload power plants In 2009, approximately 87% of the Company s domestic generation output was from plants fueled by coal or nuclear fuel. In many of the competitive markets where NRG operates, the price of power is typically set by the marginal costs of natural gas-fired and oil-fired power plants that historically have higher variable costs than solid-fuel baseload power plants. As a result of NRG s lower marginal cost for baseload coal and nuclear generation assets, the Company expects the baseload assets in ERCOT to generate power the 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 Houston, New York City, southwestern Connecticut 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

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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.

Performance Metrics

The following table contains a summary of NRG s operating revenues by segment for the years ended December 31, 2009, 2008 and 2007, as discussed in Item 14 Note 18, *Segment Reporting,* to the Consolidated Financial Statements.

	Year Ended December 31, 2009 (In millions)							
Region	**Energy Revenues**	**Capacity Revenues**	**Retail Revenues**	**Risk Management Activities**	**Contract Amortization**	**Thermal Revenues**	**Other Revenues**	**Total Operating Revenues**
Reliant Energy[(a)]	$	$	$ 4,440	$	$ (258)	$	$	$ 4,182
Texas	2,439	193		229	57		28	2,946
Northeast	489	407		277			28	1,201
South Central	360	269		(71)	22		1	581
West	34	122		(8)			2	150
International	52	79					13	144
Thermal	7	7		4		100	17	135
Corporate and Eliminations	(350)	(47)		(13)			23	(387)
Total	$ 3,031	$ 1,030	$ 4,440	$ 418	$ (179)	$ 100	$ 112	$ 8,952

(a) For the period May 1, 2009 to December 31, 2009.

	Year Ended December 31, 2008 (In millions)						
Region	**Energy Revenues**	**Capacity Revenues**	**Risk Management Activities**	**Contract Amortization**	**Thermal Revenues**	**Other Revenues**	**Total Operating Revenues**
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

	Year Ended December 31, 2007						
Region	Energy Revenues	Capacity Revenues	Risk Management Activities	Contract Amortization	Thermal Revenues	Other Revenues	Total Operating Revenues
	(In millions)						
Texas	$ 2,698	$ 363	$ (33)	$ 219	$	$ 40	$ 3,287
Northeast	1,104	402	27			72	1,605
South Central	404	221	10	23			658
West	4	122				1	127
International	42	83				15	140
Thermal	13	5			125	16	159
Corporate and Eliminations						13	13
Total	$ 4,265	$ 1,196	$ 4	$ 242	$ 125	$ 157	$ 5,989

In understanding NRG s wholesale generation 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.

Net heat rate The net heat rate for the Company s fossil-fired power plants represents the total amount of fuel in BTU required to generate one net kWh provided.

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.

In addition, the Company believes that retail customer counts and weighted average retail customer counts are particularly important performance metrics when evaluating this segment. For further results of Reliant Energy s business metrics see Item 6 *Management s Discussion and Analysis of Financial Conditions and Results of Operation.*

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, 2009, and 2008:

		Year Ended December 31, 2009			
Region	**Net Owned Capacity (MW)**	**Net Generation (MWh)**	**Annual Equivalent Availability Factor**	**Average Net Heat Rate Btu/kWh**	**Net Capacity Factor**
		(In thousands of MWh)			
Texas[(a)]	11,340	44,993	88.2%	10,200	38.4%
Northeast[(b)]	7,015	9,220	89.2	10,900	13.5
South Central	2,855	10,398	89.6	10,500	41.1
West	2,150	1,279	86.5%	12,300	8.2%

		Year Ended December 31, 2008			
Region	**Net Owned Capacity (MW)**	**Net Generation (MWh)**	**Annual Equivalent Availability Factor**	**Average Net Heat Rate Btu/kWh**	**Net Capacity Factor**
		(In thousands of MWh)			
Texas[(a)]	11,010	46,937	88.1%	10,300	49.6%
Northeast[(b)]	7,202	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%

(a) Net generation (MWh) does not include Sherbino I Wind Farm LLC, 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, 2009, NRG had 4,607 employees, approximately 1,640 of whom were covered by U.S. bargaining agreements. During 2009, the Company did not experience any labor stoppages or labor disputes at any of its facilities. The increase in the number of employees is primarily due to the Company s acquisition of Reliant Energy in May 2009.

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 baseload generation assets. The objective of these hedging strategies is to stabilize the cash flow generated by NRG s portfolio of assets.

The following table summarizes NRG s U.S. baseload capacity and the corresponding revenues and average natural gas prices resulting from baseload hedge agreements extending beyond December 31, 2010, and through 2014:

	2010	2011	2012	2013	2014	Annual Average for 2010-2014
	(Dollars in millions unless otherwise stated)					
Net Baseload Capacity (MW) [a]	8,557	8,477	8,450	8,450	8,295	8,446
Forecasted Baseload Capacity (MW) [b]	7,217	7,065	7,272	7,268	7,138	7,192
Total Baseload Sales (MW)[c][h]	7,175	4,882	3,229	1,951	797	3,607
Percentage Baseload Capacity Sold Forward[d]	99%	69%	44%	27%	11%	50%
Total Forward Hedged Revenues[e][f][g]	$ 3,535	$ 2,246	$ 1,688	$ 944	$ 345	$ 1,752
Weighted Average Hedged Price ($ per MWh)[e]	$ 56	$ 53	$ 60	$ 55	$ 49	$ 55
Weighted Average Hedged Price ($ per MWh) excluding South Central region[f]	$ 59	$ 55	$ 68	$ 71	$	$ 60
Average Equivalent Natural Gas Price ($ per MMBtu)	$ 7.57	$ 7.15	$ 7.91	$ 7.44	$ 7.18	$ 7.49
Average Equivalent Natural Gas Price ($ per MMBtu) excluding South Central region	$ 7.67	$ 7.18	$ 8.51	$ 8.71	$	$ 7.73

(a) Nameplate capacity net of station services reflecting unit retirement schedule.

(b) Expected generation dispatch output (MWh) based on budget forward price curve, which is then divided by 8,760 hours (8,784 hours in 2012) to arrive at MW capacity. The dispatch takes into account planned and unplanned outage assumptions.

(c) 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, 2009 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.

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

(e) Represents all North American baseload sales, including energy revenue and demand charges.
(f) The South Central region s weighted average hedged prices ranges from $43/MWh $50/MWh. These prices include demand charges and an estimated energy charge.
(g) Include frozen OCI primarily from Merrill Lynch CSRA sleeve unwind.
(h) Include the inter-company sales from wholesale business to Reliant Energy s retail business.

Reliant Energy sells electricity on fixed price or indexed products, and these contracts have terms typically ranging from one month to five years. In a typical year, the Company sells approximately 50 TWh of load (comprised of approximately 40% to Mass customers and approximately 60% to C&I customers), but this amount can be affected by weather, economic conditions and competition. The wholesale supply is typically purchased as the load is contracted in order to secure profit margin. The wholesale supply is purchased from a combination of NRG s wholesale portfolio and other third parties, depending on the existing hedge position for the NRG wholesale portfolio at the time.

Capacity Revenue Sources

NRG revenues and free cash flows benefit from capacity/demand payments originating from either market clearing capacity prices, Reliability Must-Run, or RMR, Resource Adequacy, or RA, contracts and tolling arrangements as many of NRG s plants are well situated within load pockets and make critical contributions to system stability. Specifically, in the Northeast, the Company s largest sources for capacity revenues are derived either from market capacity auctions including New York, PJM Interconnection LLC, or PJM and New England auctions and/or RMRs. In South Central, NRG earns significant capacity revenue from its long-term full-requirements load contracts with 10 Louisiana distribution cooperatives, which are not unit specific. Of the ten contracts, seven expire in 2025 and account for 50% of the contract load, while the remaining three expire in 2014 and comprise 40% of contract load. Capacity revenues from these long terms contracts are tied to summer peak demand as well as provide a mechanism for recovering a portion of the costs for mandated environmental projects over the remaining life of the contract. In West, most of the Company s sites benefit from either tolling agreements and/or RA contracts. Texas, does not have a capacity market; Texas capacity revenues reflect bilateral transactions. Prior to NRG s acquisition of Texas Genco, the PUCT regulations required that Texas generators sell 15% of their capacity by auction at reduced rates. The Company was subsequently released from this obligation and the legacy capacity contracts expired in 2009. See each of the *Regional Business Descriptions Market Framework* below for further discussion of the plants and relevant capacity revenue eligibility.

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, 2009, NRG had purchased forward contracts to provide fuel for approximately 47% of the Company s requirements from 2010 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 34 million tons of coal in 2009, of which 96% is Powder River Basin coal and lignite. The Company is one of the largest coal purchasers in the U.S.

The following table shows the percentage of the Company s coal and lignite requirements from 2010 through 2014 that have been purchased forward:

	Percentage of Company s Requirement[(a)(b)]
2010	93%
2011	60%
2012	51%
2013	15%
2014	16%

(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.
(b) Does not include coal inventory.

As of December 31, 2009, NRG had approximately 6,280 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 five 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 South Texas Project s, or 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 of the Company s wholesale power generation segments 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 wholesale generation business segments.

The sale of electric power to retail customers is also a seasonal business with the demand for power peaking during the summer months. Weather may impact operating results and extreme weather conditions could materially affect results of operations. The rates charged to retail customers may be impacted by fluctuations in the price of natural gas, transmission constraints, competition, and changes in market heat rates.

Regional Business Descriptions

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

RELIANT ENERGY

Operating Strategy

Reliant Energy s business is to earn a margin by selling electricity to end-use customers, providing innovative and value-enhancing services to such customers, and acquiring supply for the estimated demand. As a retail energy provider, Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payment for electricity sold, and maintains call centers to provide customer service. In addition, Reliant Energy is focused on developing innovative energy solutions including the infrastructure for electric vehicles and energy efficiency tools and services for consumers to manage their energy usage. NRG presently purchases a substantial portion of Reliant Energy s supply requirements from third parties such as generation companies and power marketers and has begun the process of becoming the primary provider for their supply requirements. Transmission and distribution services are purchased from entities regulated by the PUCT and subject to ERCOT protocols.

The energy usage of Reliant Energy s retail customers varies by season, with generally higher usage during the summer period. As a result, Reliant Energy s net working capital requirements generally increase during summer months along with the higher revenues, and then decline during off-peak months.

Customer Segments

The following is a description of Reliant Energy s significant customer segments in Texas.

Mass Reliant Energy s Mass customer base is made up of approximately 1.5 million residential and small business customers in the ERCOT market with more than half located in the Houston area. Reliant Energy also serves customers in other competitive markets in ERCOT including the Dallas, Fort Worth, and Corpus Christi areas.

C&I Reliant Energy markets electricity and energy services to approximately 0.1 million C&I customers in Texas. These customers include refineries, chemical plants, manufacturing facilities, hospitals, universities, commercial real estate, government agencies, restaurants and other commercial facilities.

Market Framework

In the ERCOT market, Reliant Energy is certified by the PUCT as a retail energy provider, or REP, to contract with end-users to sell electricity and provide other value enhancing services. In addition, Reliant Energy contracts with transmission and distribution service providers, or TDSPs, to arrange for transportation to the customer. Reliant Energy activities in Texas are subject to standards and regulations adopted by the PUCT and ERCOT. Reliant Energy operates within the same ERCOT market as the Company s Texas region. For further discussion of the Texas market framework, which includes overall market structure in addition to items specific to the generation business, see Texas region Market Framework discussion, below.

For further discussion of the Company s Reliant Energy operations, see Item 14 Note 3, *Business Acquisitions,* to the Consolidated Financial Statements.

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. As of December 31, 2009, NRG s generation assets in the Texas region consisted of approximately 5,355 MW of baseload generation assets, approximately 345 MW of intermittent wind generation assets, excluding partner interests of 75 MW, in addition to approximately 5,640 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 STP. In addition, in June 2009, NRG completed construction and began commercial operations of the 520 MW Cedar Bayou 4 natural gas-fueled combined cycle generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas, of which NRG holds a 50% undivided interest. Also in 2009, NRG completed construction and began commercial operations of the 150 MW Langford wind farm located in west Texas. Both Cedar Bayou 4 and Langford are located in the ERCOT market. Power plants are generally dispatched in order of lowest operating cost and as of December 2009, approximately 59% of the net generation capacity in the ERCOT market was natural gas-fired. Generally, NRG s three solid-fuel baseload facilities and three wind farms have significantly lower operating costs than natural gas plants. NRG expects these three solid-fuel facilities to operate the majority of the time when available, subject to planned and forced outages.

Operating Strategy

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		
	2009	2008	2007
	(In thousands of MWh)		
Coal	30,023	32,825	32,648
Gas[(a)]	5,224	4,647	5,407
Nuclear[(b)]	9,396	9,456	9,724
Wind	350	9	
Total	44,993	46,937	47,779

(a) MWh information reflects the undivided interest in total MWh generation from Cedar Bayou 4 beginning June 2009.
(b) MWh information reflects the undivided interest in total MWh generated by STP.

Generation Facilities

As of December 31, 2009, NRG s generation facilities in Texas consisted of approximately 11,340 MW of generation capacity. The following table describes NRG s electric power generation plants and generation capacity as of December 31, 2009:

Plant	Location	% Owned	Net Generation Capacity (MW)[(c)]	Primary Fuel-type
Solid-Fuel Baseload Units:				
W. A. Parish[(a)]	Thompsons, TX	100.0	2,490	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			5,355	
Intermittent Units:				
Elbow Creek	Howard County, TX	100.0	120	Wind
Sherbino	Pecos County, TX	50.0	75	Wind
Langford	Christoval, TX	100.0	150	Wind
Total Intermittent Baseload			345	
Operating Natural Gas-Fired Units:				
Cedar Bayou	Baytown, TX	100.0	1,495	Natural Gas
Cedar Bayou 4	Baytown, TX	50.0	260	Natural Gas
T. H. Wharton	Houston, TX	100.0	1,025	Natural Gas
W. A. Parish[(a)]	Thompsons, TX	100.0	1,175	Natural Gas
S. R. Bertron	Deer Park, TX	100.0	765	Natural Gas

Greens Bayou	Houston, TX	100.0	760	Natural Gas
San Jacinto	LaPorte, TX	100.0	160	Natural Gas
Total Operating Natural Gas-Fired			5,640	
Total Operating Capacity			11,340	

(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.

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 U.S. 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 2,490 MW as of December 31, 2009. Two of these units are 650 MW and 655 MW steam units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 575 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 Reduction systems, 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, 2009. The first unit is an 830 MW steam unit that was placed in commercial service in 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.

The lignite used to fuel the Texas region s Limestone facility is obtained from a surface mine, or the Jewett mine, adjacent to the Limestone facility under a long-term contract with Texas Westmoreland Coal Co., or TWCC. The contract is based on a cost-plus arrangement with incentives and penalties to ensure proper management of the mine. NRG has the flexibility to increase or decrease lignite purchases with adequate notice. The mining period was extended through 2018 with an option to extend the mining period by two five-year intervals. The agreement ensures lignite supply to NRG and confirms NRG s responsibility for the final reclamation at the mine. Subject to the terms of the contract, NRG has the ability to step in and operate the mine under certain circumstances.

STP Electric Generating Station STP is one of the newest and largest nuclear-powered generation plants in the U.S. 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, 2009, 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 United States Nuclear Regulatory Commission, or 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 2009, hourly demand ranged from a low of 21,350 MW to a high of 63,534 MW. The ERCOT market has limited interconnections compared to other markets in the U.S. currently limited to 1,086 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.

As of December 2009, installed generation capacity of approximately 84,000 MW existed in the ERCOT market, including 3,000 MW of generation that has suspended operations, or been mothballed . Natural gas-fired generation represents approximately 50,000 MW, or 59%. Approximately 24,000 MW, or 29%, was lower marginal cost generation capacity such as coal, lignite and nuclear plants. NRG s coal and nuclear fuel baseload plants represent approximately 5,355 MW net, or 22%, of the total solid-fuel baseload net generation capacity in the ERCOT market. Additionally, NRG commenced commercial operations of the 520 MW Cedar Bayou 4 natural gas-fueled combined cycle generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas, of which NRG holds a 50% undivided interest. Also in 2009, NRG commenced commercial operations of the 150 MW Langford wind farm located in west Texas. Both Cedar Bayou 4 and Langford are located in the ERCOT market.

The ERCOT market has established a target equilibrium reserve margin level of approximately 12.5%. The reserve margin for 2009 was 16.8% forecast to increase to 21.8% for 2010 per ERCOT s latest Capacity Demand and Reserve Report. There are currently plans being considered by the PUCT to build a significant amount of transmission from west Texas and continuing across the state to enable wind generation to reach load. The ultimate impact on the reserve margin and wholesale dynamics from these plans are unknown.

In the ERCOT market, buyers and sellers enter into bilateral wholesale capacity, power and ancillary services contracts or may participate in the centralized ancillary services market, including balancing energy, with the ERCOT administers. Published in August 2009, the 2008 State of the Market Report for the ERCOT Wholesale Electricity Markets from the Independent Market Monitor indicated that natural gas is typically the marginal fuel in the ERCOT market. As a result of NRG s lower marginal cost for baseload coal and nuclear generation assets, the Company expects these ERCOT assets to generate power the majority 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 Elbow Creek, Langford, and Sherbino 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 to 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, or LMP, 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.

NORTHEAST

NRG s second largest asset base is located in the Northeast region of the U.S. with generation assets 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. As of December 31, 2009, NRG s generation assets in the Northeast region consisted of approximately 1,870 MW of baseload generation assets and approximately 5,145 MW of intermediate and peaking assets.

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		
	2009	**2008**	**2007**
	(In thousands of MWh)		
Coal	7,945	11,506	11,527
Oil	134	349	1,169
Gas	1,141	1,494	1,467
Total	9,220	13,349	14,163

Certain of the Northeast region assets are located in or near load centers and inside 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 preceding the Forward Capacity Market, or FCM, were effective December 1, 2006. In all seven 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 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 Certain of the Northeast region s Connecticut assets have been designated as required to be available to ensure reliability to ISO-NE. These assets are subject to 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 2009, 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, 2009, NRG s generation facilities in the Northeast region consisted of approximately 7,015 MW of generation capacity and are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity (MW) (c)	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(b)	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	135	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			7,015	

(a) In 2003, Somerset entered into an agreement with the Massachusetts Department of Environmental Protection, or MADEP, to retire or repower 100MW Unit 6, 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. Subsequently, NRG requested of ISO-NE that it be allowed to place Unit 6 on deactivated reserve effective January 2, 2010, in advance of the required shut-down date. On December 21, 2009, ISO-NE granted NRG s request.

(b) Indian River Unit 2 will be retired May 1, 2010 and Indian River Unit 1 will be retired May 1, 2011. In addition, NRG and DNREC announced a proposed plan, subject to definitive documentation, that would shut down Indian River Unit 3 by December 31, 2013.

(c) Actual capacity can vary depending on factors including weather conditions, operational conditions and other factors.

The table below reflects the plants and relevant capacity revenue sources for the Northeast region:

	Sources of Capacity Revenue: Market Capacity, RMR and Tolling

Region, Market and Facility	Zone	Arrangements
Northeast Region:		
NEPOOL (ISO-NE):		
Devon	SWCT	LFRM/FCM
Connecticut Jet Power	SWCT	LFRM/FCM
Montville	CT ROS	RMR[(a)]/FCM
Somerset	SE MASS	LFRM/FCM
Middletown	CT ROS	RMR[(a)]/FCM
Norwalk Harbor	SWCT	RMR[(a)]/FCM
PJM:		
Indian River	PJM East	DPL South
Vienna	PJM East	DPL South
Conemaugh	PJM West	PJM MAAC
Keystone	PJM West	PJM MAAC
New York (NYISO):		
Oswego	Zone C	UCAP ROS
Huntley	Zone A	UCAP ROS
Dunkirk	Zone A	UCAP ROS
Astoria Gas Turbines	Zone J	UCAP NYC
Arthur Kill	Zone J	UCAP NYC

(a) Per the terms of the RMR agreement, any FCM transition capacity payments are offset against approved RMR payment. RMR agreements will expire June 1, 2010, the first day of the First Installed Capacity Commitment Period of the FCM.

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 fire 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 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 installed back-end control facilities at Dunkirk in 2009. All units have returned to service and the fabric filters are functioning as designed.

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 in January 2009, Huntley Units 67 and 68 fabric filters were placed in service and they are functioning as designed.

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. On February 3, 2010, the Company together with DNREC announced a proposed plan to retire the

155 MW unit 3 by December 31, 2013. The plan, subject to definitive documentation, extends the operable period of the plant two years beyond the December 31, 2011 date and avoids the incremental cost of control technology. The 410 MW unit 4 is not affected by this proposal, and in 2009, the Company began construction to install selective catalytic reduction systems, scrubbers and fabric filters on this unit. These controls are scheduled to be operational at the end of 2011.

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

NRG is the third largest generator in the South Central region of the U.S. with generation assets within the control areas of the Southeastern Electric Reliability Council/Entergy, or SERC-Entergy, region. As of December 31, 2009, 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 1,495 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 ten 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 455 MW of peaking generation in Rockford, Illinois under the PJM region.

The South Central region lacks a regional transmission organization, or RTO, 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 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 ten 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		
	2009	2008	2007
	(In thousands of MWh)		
Coal	10,235	10,912	10,812
Gas	163	236	118
Total	10,398	11,148	10,930

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, 2009, are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity (MW) [(b)]	Primary Fuel type
Big Cajun II[(a)]	New Roads, LA	86.0	1,495	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	155	Natural Gas
Sterlington	Sterlington, LA	100.0	175	Natural Gas
Total South Central			2,855	

(a) NRG owns 100% of Units 1 & 2; 58% of Unit 3.
(b) Actual capacity can vary depending on factors including weather conditions, operational conditions and other factors.

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 1,745 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 1,495 MW of the plant. All three units have been upgraded with advanced low-NO_x 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, 2009, NRG had long-term all-requirements contracts with ten Louisiana distribution cooperatives with initial terms ranging from ten to twenty-five years. Of the ten contracts, seven expire in 2025 and account for 50% of the contract load, while the remaining three expire in 2014 and comprise 40% of contract load. In addition to earning energy revenues from these cooperative agreements, NRG also earns capacity revenues which are tied to summer peak demand as well as provide a mechanism for recovering a portion of the costs for mandated environmental projects over the remaining life of the contract. During 2009, NRG successfully executed all-requirements contracts with three Arkansas municipalities with service start dates as early as mid-year 2010. These new contracts account for over 500 MW of total load obligations for NRG and the South Central region, more than offsetting the South Central region s reduction in load in 2009 due to the expiration of a Louisiana distribution cooperative contract. In addition, NRG also has certain long-term contracts with the Municipal Energy Agency of Mississippi, Mississippi Delta Energy Agency, South Mississippi Electric Power Association, and Southwestern Electric Power Company, 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, depending upon the then-current gas commodity pricing, and these purchases can be at higher prices than can be recovered under the Company s contracts. NRG has to date successfully mitigated the risk of these peak contract load requirements by contracting for new large industrial or municipal loads outside contract pricing at market 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 generation assets in the West region of the U.S. are primarily located in the California Independent System Operator, or CAISO, control area. The West region s generation assets 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. 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 a 50% interest in the Saguaro power plant which is a 90 MW baseload, gas-fired plant located in Nevada and a 20 MW photovoltaic solar facility located in southern California.

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 renewable and repowering projects that leverage off of existing capabilities, assets and sites, as well as the preservation and ultimate realization of the commercial value of the underlying real estate. There are four principal components to this strategy: (i) capturing the value of the portfolio s generation assets through a combination of forward contracts and market sales of capacity, energy, and ancillary services; (ii) leveraging existing site control and emission allowances to permit new, more efficient generating units at existing sites; (iii) developing renewable project opportunities that are positioned to compete for long-term contracts offered by load serving entities; and (iv) 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 2010, on a tolling basis, and recovers its operating costs plus a capacity payment. For calendar year 2009, El Segundo station entered into 548 MWs of RA capacity contracts and placed the capacity in the market through a portfolio of forward contracts. For calendar year 2010, El Segundo station entered into 335 MWs of RA capacity contracts and retained its rights to sell energy and ancillary services into the market. Cabrillo II sold 188 MW of RA capacity for calendar year 2009 and 2010, and 88 MW for the period January 1, 2011 through November 30, 2013. 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 NV Energy (formerly Nevada Power) and two steam hosts. The Saguaro plant is contracted to NV Energy through 2022, one steam host, Olin (formerly known as Pioneer), whose contract was extended in 2009 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.

On November 20, 2009, NRG, through its wholly owned subsidiary NRG Solar LLC, acquired Blythe Solar from First Solar, Inc. On December 18, 2009, construction was completed and commercial operation began for the 20 MW utility-scale photovoltaic, or PV, solar facility located in Riverside County in southeastern California. The Blythe Solar PV field will provide electricity to Southern California Edison, or SCE, under a 20-year Power Purchase Agreement, or PPA. First Solar will operate and maintain the solar facility under contract.

Generation Facilities

NRG s power generation assets in the West region as of December 31, 2009, are summarized in the table below:

Net

Plant	Location	% Owned	Generation Capacity (MW) [(a)]	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
Blythe Solar	Blythe, CA	100.0	20	Solar
Total West Region			2,150	

(a) Actual capacity can vary depending on factors including weather conditions, operational conditions and other factors.

The table below reflects the plants and relevant capacity revenue sources for the West region:

Region, Market and Facility	**Zone**	**Sources of Capacity Revenue: Market Capacity, RMR and Tolling Arrangements**
West Region:		
California (CAISO):		
Encina	CAISO	Toll (a)
Cabrillo II	CAISO	RA Capacity (b)
El Segundo Power	CAISO	RA Capacity (c)
Long Beach	CAISO	Toll(d)
Blythe	CAISO	Toll (e)

(a) Toll expires December 31, 2010.
(b) The RMR agreement covering 160 MW expired on 12/31/2008 and was replaced by RA contracts covering the entire Cabrillo II portfolio during 2009 (RA contracts for 88 MW run through November 30, 2013).
(c) El Segundo includes approximately 670MW economic call option and 548 MW of RA contracts for 2009.
(d) NRG has purchased back energy and ancillary service value of the toll through July 31, 2011. Toll expires August 1, 2017.
(e) Blythe reached commercial operations on December 18, 2009 and sells all its energy under a 20-year PPA.

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 NO_x burner modifications and Selective Catalytic Reduction, or 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 CAISO. 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.

Blythe Solar Blythe Solar consists of a 20 MW utility-scale photovoltaic, or PV, solar facility located in Riverside County in southeastern California. The site uses approximately 350,000 photovoltaic solar modules that turn sunlight directly into electricity. The Blythe Solar site covers approximately 200 acres. The output of the facility is fully contracted to SCE under a 20-year PPA.

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 nodal 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. CAISO s new market, known as Market Redesign and Technology Upgrade, or MRTU, became operational on April 1, 2009. MRTU established a day-ahead market for energy and ancillary services and settles 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 set at 20% for 2010 and the Governor, by Executive Order, has directed that the standard be increased to 33% by 2020. This increase is expected to create greater demand for low emission resources. The intermittent and remote nature of most renewable resources will create a strong demand for flexible load pocket resources. NRG s California portfolio may also be impacted by legislation and 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 the Company s 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. The El Segundo repowering project has been selected and contracted by a load-serving entity and is in the final stages of permitting. The project is planned to be in operation in the summer of 2013. A permit application for the Encina repowering project has been submitted and is under evaluation by the California Energy Commission. The Encina repowering project has cost and location advantages that enhance its competitive prospects. Both projects are supported by air emissions credits that have been banked after the retirement of older generating units.

INTERNATIONAL

As of December 31, 2009, NRG, through certain foreign subsidiaries, had investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity. 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, 2009, 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
Total International			1,005	

Australia Through a joint venture, NRG holds a 37.5% equity interest in the Gladstone power station, or Gladstone. 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.

Germany 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. The 900 MW Schkopau generating plant, in which the Company has a 41.9% equity interest, is fueled with lignite.

On June 10, 2009, NRG completed the sale of its 50% ownership interest in Mitteldeutsche Braunkohlengesellschaft mbH, or MIBRAG, to a consortium of Severoćeské doly Chomutov, a member of the CEZ Group, and J&T Group. Mibrag B.V. s principal holding is MIBRAG, which is jointly owned by NRG and URS Corporation. For further discussion of MIBRAG disposition, see Item 14 Note 4, *Discontinued Operation and Dispositions,* to the Consolidated Financial Statements.

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, 2009, NRG Thermal provided steam heating to approximately 495 customers and chilled water to 100 customers in five different cities in the U.S. The Company s thermal businesses in Pittsburgh, Harrisburg and San Francisco are regulated by their respective state s 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 two industrial customers with high-pressure steam. NRG Thermal also owns an 88 MW combustion turbine peaking generation facility and a 16 MW coal-fired cogeneration facility in Dover, Delaware as well as a 12 MW gas-fired project in Harrisburg, Pennsylvania. Approximately 37% of NRG Thermal s revenues are derived from its district heating and chilled water business in Minneapolis, Minnesota.

The table below reflects relevant electric capacity revenue sources for the Thermal region:

Region and Facility	Zone	Sources of Capacity Revenue: Market Capacity, RMR and Tolling Arrangements
Thermal:		
Dover	PJM East	DPL South
Paxon Creek	PJM West	PJM MAAC

New and On-going Company Initiatives and Development Projects

NRG has a comprehensive set of initiatives and development projects that supports it s strategy focused on: (i) top decile and enhanced operating performance; (ii) repowering of power generation assets at existing sites and development of new power generation projects; (iii) empowering retail customers with distinctive products and services; (iv) engaging in a proactive capital allocation plan; and (v) pursuing selective acquisitions, joint ventures, divestitures and investment in new energy-related businesses and new technologies in order to enhance the Company s asset mix and combat climate change.

***FOR*NRG Update**

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 appropriate historic baselines.

The 2009 *FOR*NRG goal was a 20 basis point improvement in ROIC which corresponds to approximately $30 million in cash flow. As of December 31, 2009, the Company exceeded its 2009 goal with a 50.37 basis point improvement in ROIC, which is equivalent to approximately $76 million in cash flows. The performance of the plants coupled with strategic projects undertaken by corporate functions is evidenced in the overall corporate performance. During 2010, the Company expects to progress further toward the program goal of 100 basis point ROIC improvement by 2012.

*Repowering*NRG Update

NRG has several projects in varying stages of development that include the following: a new generating unit at the Limestone power station and the repowering of Encina and El Segundo sites. In addition, on December 22, 2009, NRG entered into a 13-year agreement with University Medical Center of Princeton to provide comprehensive high efficiency energy to this 237 room hospital. The hospital, which is currently under construction, will use electricity from an NRG owned combined heat and power system that includes the production of steam for heating and chilled water for air conditioning, achieved by means of a thermal energy storage system. Construction of the facility will commence in early 2010 with expected commercial operation by the first quarter 2012. The development of these projects is subject to certain conditions and milestones which may effect the Company s decision to pursue further development of these projects. The Company s development projects are generally subject to certain conditions, milestones, or other factors that may result in the Company s decision to no longer pursue development of these projects.

The following is a summary of the 2009 repowering projects that have been completed and operating as well as those still under construction. In addition, NRG continues to participate in active bids in response to requests for proposals in markets in which it operates.

Plants Completed and Operating

Cedar Bayou Generating Station On June 24, 2009, NRG and Optim Energy, LLC, or Optim Energy, completed construction and began commercial operation of a new natural gas-fueled combined cycle generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas. NRG and Optim Energy have a 50/50 undivided interest basis in the 520 MW generating plant. NRG is the operator of the plant and Optim Energy is acting as energy manager for Cedar Bayou unit 4. Cedar Bayou unit 4 is providing the Company a net capacity of 260 MW given NRG s 50% ownership.

Plants under Construction

GenConn Energy LLC In a procurement process conducted by the Department of Public Utility Control, or DPUC, and finalized in 2008, GenConn Energy, 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 operation 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, construction and procurement of the eight GE LM6000 combustion turbines required for the projects. Construction has begun at the Devon facility while site demolition and excavation has begun at the Middletown location.

On April 27, 2009, GenConn closed on $534 million of project financing related to these projects. The project financing includes a seven-year project backed term loan and a five-year working capital facility which together total $291 million. In addition, NRG and United Illuminating have each closed an equity bridge loan of $121.5 million, which together total $243 million. NRG is funding its share of costs related to these projects via year to date draw downs on the equity bridge loan of $108 million as of December 31, 2009. In August 2009, GenConn began to draw on the project financing facility to cover costs related to the Devon project.

Retail Development

Electric Vehicle Services In 2009, NRG began development of a service business to support the mass deployment of electric vehicles through its subsidiary Reliant Energy. In 2010, Reliant Energy plans to begin selling new products and services that enable both public and home charging of electric vehicles. In conjunction with this effort, Reliant Energy announced in November 2009 that it will work with Nissan Motor Co. to make the City of Houston a launch city for the broader use of electric vehicles. Also in November 2009, Reliant Energy announced a joint project with the City of Houston to add plug-in fleet vehicles as well as public charging stations to support them.

Smart Energy In 2009, Reliant Energy submitted an application to the Department of Energy, or DOE, requesting $20 million in the Smart Grid Investment Grant funds for a three-year project to bring a suite of Smart Grid enabled products to residential customers. Reliant Energy s project was selected by the DOE in October 2009. The Company is now in the process of negotiating a definitive agreement with the DOE and expects to begin the project in the first quarter 2010. Reliant Energy s share of the project costs are expected to be $45.5 million over a three-year period.

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.

Nuclear Development

Nuclear Innovation North America In 2008, NRG formed Nuclear Innovation North America LLC, or 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 South Texas Projects Units 3 and 4, or STP Units 3 and 4. NINA is currently owned 88% by NRG and 12% by Toshiba American Nuclear Energy Corporation, or TANE, a wholly owned subsidiary of Toshiba Corporation.

Based on its current NRC schedule, the Company expects to achieve commercial operation for Unit 3 in 2016 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. NINA is in the process of assessing the potential for increasing the gross output of the units through an uprate amendment, shortly after receipt of the Combined Operating License, or COL. This would increase the rated gross output of the units to approximately 3,000 MWs. The NRC licensing process also provides an opportunity for individuals to intervene in the COL application as an ordinary part of the COL application process. At this time, several individuals have elected to intervene in the COL proceedings and NINA is currently in the process of defending, addressing or eliminating, as appropriate, all open contentions by the interveners.

The DOE has confirmed that the STP Units 3 and 4 project is one of four projects selected for further due diligence and negotiation leading to a conditional commitment under the DOE loan guarantee program. NINA is currently in discussions with the DOE on the specific terms and amount to be loaned for the project. NRG believes DOE loan guarantee support is critical to new nuclear development projects. In addition to U.S. loan guarantees, NINA is seeking to augment potential financial support from the DOE by actively pursuing additional loan guarantees through the Japanese government. The project is expected to have significant Japanese content.

In 2009, NINA executed an EPC agreement with TANE to build STP Units 3 and 4. The EPC agreement is structured so as to assure that the new plant is constructed on time, on budget and to exacting standards. There are three primary cost elements that make up the total cost of the STP Units 3 and 4. The largest is the EPC Cost, which is the cost the prime contractor will charge for the engineering, construction, procurement, and material/equipment of the STP Units 3 and 4. The second cost is what is referred to as Owners Cost, comprised of licensing fees, contingency, internal and agent resource costs, operations training, owner s engineers and other third party support costs. The final cost component is the Financing Cost, which includes subsidy costs of the DOE loan guarantee, interest during construction, and support services associated with putting the financing in place.

On December 30, 2009, NINA had received an estimate from TANE, the prime contractor, containing the overnight estimate of the EPC Cost. The estimate was approximately $11.5 billion for STP Units 3 and 4 with an opportunity to reduce cost subject to certain specification changes. Based on the estimate provided by TANE and the Company s internal assessments, NINA continues to believe that its stated target of $9.8 billion, or $3,229/kW based on 3,000 MW gross output is achievable. Cost reductions will be achieved through a combination of specification changes and the re-alignment of risks and responsibilities among key project stakeholders.

Owners Costs for the project, on an escalated basis, are estimated to total approximately $2.1 billion during the construction period. This is primarily comprised of the costs for NRG s agent STPNOC, owners contingency and the initial fuel load. Financing Costs are estimated to be approximately $1.5 billion during the construction period, and are comprised of the variables described above.

On February 17, 2010, an agreement in principle was reached with CPS for NINA to acquire a controlling interest in the project to construct STP Units 3 and 4 through a settlement of the litigation between the parties. As part of the agreement, NINA would increase its ownership in the STP Units 3 and 4 project from 50% to 92.375% and would assume full management control of the project. NINA would also pay $80 million to CPS, subject to receipt of a conditional DOE loan guarantee. The first $40 million would be promptly paid after receipt of the guarantee and the other half six months later. An additional $10 million would be donated by NRG over four years in annual payments of $2.5 million to the Residential Energy Assistance Partnership in San Antonio. As part of the agreement with CPS, all litigation would be dismissed with prejudice. The parties continue to negotiate terms regarding final documentation of the agreement in principle.

The agreement would enable the STP Unit 3 and 4 project expansion to move forward and allow NINA to continuing pursuing its application for a conditional loan guarantee from the DOE. If NINA is not successful in reaching a final settlement with CPS, obtaining a conditional loan guarantee or selling down its interest in STP Units 3 and 4, there could be negative implications for the project that may result in a reassessment of the probability of success of the project and an impairment of the value of the capitalized assets for STP Units 3 and 4. An impairment would result in a permanent write-down of the $299 million of construction-in-progress capitalized through December 31, 2009, plus any amounts capitalized through the impairment date.

Renewable Development

NRG has routinely invested in the development of renewable energy projects such as wind, solar and biomass, to support the Company s econrg initiative. NRG s renewable strategy is to capitalize on both first mover advantages and the Company s inherent regional presence. The following are the renewable development projects that Company is actively engaged in:

Solar Development

NRG intends to leverage its market knowledge, functional expertise, cash position and tax appetite to be the leading developer and owner of assets in the high growth solar power industry. The Company intends to align itself with technology providers who it believes are or will be the leading technologies in the industry. These strategic relationships will exist with photovoltaic, or PV, concentrated solar power, or CSP, Sterling Dish, and storage technologies. NRG will focus on projects that are supported by long term off-take agreements and have the ability to secure either commercial bank or DOE funding to maximize equity returns. In 2009, NRG completed the following activities:

Acquisition and completion of Blythe Solar On November 20, 2009, NRG, through its wholly-owned subsidiary NRG Solar LLC, acquired FSE Blythe 1, LLC, or Blythe Solar, from First Solar, Inc. On December 18, 2009, construction was completed and commercial operation began for the 20 MW utility-scale PV solar facility located in Riverside County in southeastern California. The Blythe Solar PV field provides electricity to Southern California Edison, or SCE, under a 20-year PPA. The site uses approximately 350,000 photovoltaic solar modules that turn sunlight directly into electricity. The Blythe Solar site covers approximately 200 acres of held land which is fully permitted and is connected to SCE s electrical distribution grid. The project is eligible for a cash grant from the Department of Treasury and NRG will file an application for an $18 million grant.

Agreement with eSolar On June 1, 2009, NRG completed an agreement with eSolar, a leading provider of modular, scalable solar thermal power technology, to acquire the development rights for up to 465 MW of solar thermal power plants at sites in California and the Southwest. The first plant is anticipated to begin producing electricity as early as 2011, subject to certain technology demonstration milestones being pursued by eSolar and a successful financial closing in 2010. At the closing with eSolar, NRG invested $5 million for an equity interest in eSolar and $5 million for deposits and land purchase options associated with development rights for three projects on sites in south central California and the Southwest U.S. as well as a portfolio of PPAs to develop, build, own and operate up to 10 eSolar modular solar generating units at these sites. These development assets will use eSolar s CSP, technology to sell renewable electricity under contracted PPAs with local utilities.

NRG has three projects in various stages of development: NRG New Mexico SunTower, Alpine SunTower and Desert View SunTower. While each of these projects has an anticipated commercial operation date, the development of these projects are subject to certain conditions and milestones which may effect the Company s decision to pursue further development of these projects.

Wind Development

NRG is an active participant in both onshore and offshore wind energy across its core regions. As part of this strategy, the Company actively engages in the development, acquisition, divestiture and establishment of joint ventures of wind projects. In the Northeast, there are strong offshore wind resources located near major load centers which can support projects of a size and scale larger than most on land wind and other renewable projects in the region. NRG looks to achieve a first-mover advantage in the U.S. offshore wind market through the development, construction and operation of projects in the region, as evidenced by the NRG s acquisition of Bluewater Wind in the fourth quarter 2009. In 2009, NRG completed the following activities:

Bluewater Wind Acquisition On November 9, 2009, NRG through its wholly-owned subsidiary, NRG Bluewater Holdings LLC, completed the acquisition of a 100% interest in all the subsidiaries of Bluewater Wind LLC (such subsidiaries, with NRG Bluewater Holdings LLC, or NRG Bluewater) as part of the Company s strategy to promote development of renewable energy projects in its core regions. NRG Bluewater currently has a number of offshore wind energy projects that are in various stages of development along the eastern seaboard and the Great Lakes region of the U.S. In Delaware, NRG Bluewater has a 25-year, 200 MW PPA with Delmarva Power & Light Company that has been approved by the Delaware Public Service Commission and other state agencies. On December 8, 2009, NRG Bluewater was also selected to finalize a power purchase agreement from the State of Maryland to provide up to 55 MW of wind generation from the Delaware project. In 2009, NRG Bluewater was awarded a $4 million rebate from the state of New Jersey to build a meteorological tower, which would collect wind and other data from a site off the coast of New Jersey.

Langford Wind Project On December 8, 2009, NRG announced the completion of its Langford project, a wholly-owned 150 MW wind farm located in Tom Green, Irion, and Schleicher Counties, Texas. The Company funded and developed this wind farm which consists of 100 General Electric 1.5 MW wind turbines. The project is eligible for a cash grant from the Department of Treasury and NRG has filed an application for an $84 million grant.

Padoma Wind On January 11, 2010, NRG sold its terrestrial wind development company, Padoma Wind Power LLC, or Padoma, to Enel North America, Inc., or Enel. NRG acquired Padoma in 2006 to develop terrestrial wind projects. NRG is maintaining its existing ownership interest in its three Texas wind farms Sherbino, Elbow Creek and Langford. In addition, NRG will maintain a strategic partnership with Enel to evaluate potential opportunities in renewable energy. NRG will retain a Right of First Offer should Enel seek an equity partner in Padoma projects.

Biomass Development

NRG has several biomass projects in varying stages of development, including a pilot project at the Big Cajun II facility to be renewably fueled with switchgrass and high-biomass sorghum, as well as the retrofit a steam unit at Montville Station to enable the unit to use clean wood biomass to produce up to 40 MW of renewable energy.

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. Certain of the Reliant Energy entities are competitive Retail Electric Providers, or REPs, and as such are subject to the rules and regulations of the PUCT governing REPs. 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 U.S. 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 an 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 U.S. 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 with the violation and/or suspension or revocation of their market-based rate authority, as well as criminal and civil penalties. As a condition of the orders granting NRG market-based rate authority, NRG is required to file regional market updates demonstrating 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 April 27, 2009 and July 21, 2009, FERC accepted the Company s updated market power analyses for its Northeast and South Central assets, respectively. NRG s next such market power update filing is due June 30, 2010, for its CAISO and southwest assets.

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 entity 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 14 Note 7, *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 the PUCT. The 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. Certain of its subsidiaries within the Texas region are also subject to regulatory oversight as a power marketer or as a Qualified Scheduling Entity. 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. Certain of the Reliant Energy entities are competitive Retail Electric Providers, or REPs, and as such are subject to the rules and regulations of the PUCT governing REPs.

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.

For further discussion on regulatory developments see Item 14 Note 23, *Regulatory Matters,* to the Consolidated Financial Statements.

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 offer 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.

On October 6, 2008, as part of its determination of Competitive Renewable Energy Zones, or CREZ, the PUCT issued its final order approving 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 transmission expansion plan is composed of approximately 2,300 miles of new 345 kV lines and 42 miles of new 138 kV lines. In January 2009, Texas Industrial Energy Consumers, a trade organization composed of large industrial customers, appealed the PUCT s CREZ plan in state district court, seeking reversal of the final order. On March 30, 2009, the PUCT issued a final order designating the transmission utilities that plan to construct the various CREZ transmission component projects. A large number of separate transmission licensing proceedings will be required prior to construction of the CREZ facilities. In July of 2009, the PUCT approved schedules for utilities to file applications to license several of the CREZ transmission projects (to obtain certificates of convenience and necessity, or CCNs). If the CREZ projects are completed as currently anticipated, the transmission upgrades and associated wind generation could impact wholesale energy and ancillary service prices in ERCOT. There are various appeals and other challenges to CREZ that could disrupt or delay the schedule. As part of the normal ERCOT five-year planning process, transmission utilities are also planning other system improvements, 2,800 circuit miles of transmission and more than 17,000 MVA of autotransformer capacity, intended to support increasing power demand and to address transmission congestion in the ERCOT Region.

Northeast Region

New England NRG s Middletown, Montville and Norwalk facilities continue to be operated pursuant to RMR agreements. Unless terminated earlier, these RMR agreements will terminate upon the commencement of the FCM on June 1, 2010.

New York 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 2010 IRM of 18%, which is an increase of 1.5% from the 2009 requirement. This increase may be offset by lower load forecasts for 2010. 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. Of particular note to the New York City capacity market, New York Power Authority, or NYPA, retired its 885 MW Poletti facility on January 31, 2010.

West Region

California The CAISO MRTU commenced 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 generally be a positive development for its assets in the region, but additional time is needed to assess the impact of MRTU.

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

Climate Change The United States signed the Copenhagen Accord, or the Accord, which sets the stage for a worldwide approach to this global issue. Under the Accord, the U.S. has committed to a 17% reduction from 2005 emission levels of GHGs by 2020. While Congress was unable to come to agreement on climate legislation in 2009, the subject continues to be a topic for consideration in 2010. Lack of legislation will prolong the uncertainty associated with the nature and timing of GHG requirements, and therefore impact on NRG.

On December 15, 2009, the U.S. EPA issued a final rule finding that a mix of six key GHGs in the atmosphere, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride, threaten the public health and welfare. This action paves the way for finalization of the September 28, 2009, *Proposed GHG Emissions Standards for Motor Vehicles*. These actions are in response to the Supreme Court s decision in *Massachusetts v. U.S. EPA*, which requires the U.S. EPA to decide under the Clean Air Act s, or CAA, mobile source title whether GHGs contribute to climate change, and if so, promulgate appropriate regulations. Under the CAA, these regulations would render GHGs regulated pollutants and subject them to other existing requirements that affect stationary sources, including power plants. The primary impact on NRG would be a statutory requirement to install Best Available Control Technology, or BACT, determined on a case-by-case basis, for major modifications or improvements at power plants if they cause GHG emissions to increase by the statutory Prevention of Significant Deterioration, or PSD limits of 100 tons per year. The U.S. EPA also released, on September 30, 2009, a draft PSD tailoring rule for GHGs that would increase the major stationary source threshold of 25,000 tons per year of carbon dioxide equivalents. This threshold level would be used to determine (i) if an existing source would be required to obtain a Title V operating permit and (ii) if a new facility or a major modification at an existing facility would trigger PSD permitting requirements. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit and install BACT. The timing and implementation of the final motor vehicle rule, acceptance of the PSD tailoring rule and U.S. EPA s approach to BACT for GHGs could affect the level of impact to NRG s plants, and future repowering projects that have not completed their permitting process.

In 2009, in the course of producing approximately 71 million MWh of electricity, NRG s power plants emitted 59 million tonnes of CO_2, of which 53 million tonnes were emitted in the U.S., 3 million tonnes in Germany and

3 million tonnes in Australia. The impact from legislation or 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 *Repowering*NRG. Additionally, NRG s current contracts with its South Central region s cooperative customers allows for the recovery of emission-based costs.

Regulations A number of regulations are under review by U.S. EPA including CAIR, MACT, National Ambient Air Quality Standards, or NAAQS, for ozone, nitrogen dioxide, SO_2, small particle matter or $PM_{2.5}$, and the Phase II 316(b) Rule. These rules address air emissions and best practices for units with once-through-cooling. In addition, the U.S. EPA has announced that it is considering new rules regarding the handling and disposition of coal combustion byproducts. While the Company cannot predict the requirements in the final versions nor the ultimate effect that the changing regulations will have on NRG s business, NRG s planned environmental capital expenditures include 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 , or BTA, under Phase II 316(b) Rule. NRG continues to explore cost-effective alternatives that can achieve desired results. This planned investment reflects anticipated schedules and controls related to CAIR, MACT for mercury, and the Phase II 316(b) Rule which are under remand to the U.S. EPA and, as such, the full impact on the scope and timing of environmental retrofits from any new or revised regulations cannot be determined at this time.

Air On April 24, 2009, the U.S. EPA granted petitions to reconsider three NSR rules; Fugitive Emissions, $PM_{2.5}$ Implementation, and Reasonable Possibility. A notice for grant of reconsideration and administrative stay of the $PM_{2.5}$ Implementation Rule was published in the *Federal Register* on June 1, 2009. While none of these actions directly impact NRG at this point, it is unknown if any such final rules will impact future projects.

CAIR applies to 28 eastern states and Washington D.C., and caps both SO_2 and NO_x 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. The CAIR NO_x trading program went into effect on January 1, 2009 and remains in effect. Vintage 2010 and later SO_2 Acid Rain Program allowances in the CAIR region will be discounted on a 2:1 basis beginning January 1, 2010. 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 U.S. Court of Appeals for the District of Columbia, or D.C. Circuit, overturned portions of the U.S. EPA s Phase I implementation rule for the new eight-hour ozone standard. Specifically, the D.C. Circuit ruled that the U.S. EPA could revoke the one-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 NO_x emissions in severe non-attainment areas. The fees could be as high as $7,700/ton for emissions above 80% of baseline emissions levels. Depending on the determination of baseline emission levels, this could materially impact NRG s operations in Los Angeles, New York City Area and Houston.

The U.S. EPA strengthened the primary and secondary ground level ozone NAAQS, (eight hour average) from 0.08 ppm to 0.075 ppm on March 12, 2008. The U.S. EPA plans to finalize ozone non-attainment regions by March 2010 and states would likely submit plans to come into attainment 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 U.S. EPA 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 U.S. EPA and several states filed suits against a number of coal-fired power plants in mid-western and southern states alleging violations of the CAA, NSR, and, PSD requirements. The U.S. EPA previously issued two Notices 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. Further discussion on this matter can be found in Item 14 Note 22, *Commitments and Contingencies*, *Louisiana Generating, LLC*, to the Consolidated Financial Statements.

Water In July 2004, the U.S. EPA 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 BTA for minimizing adverse environmental impacts unless a facility shows that such standards would result in very high costs or little environmental benefit. As a result of a decision by the Second Circuit Court of Appeals, the U.S. EPA suspended the rule in July 2007 while preparing a revised version. The U.S. Supreme Court released a decision on the challenge on April 1, 2009, in which it concluded that the U.S. EPA does have the authority to allow a cost-benefit analysis in the evaluation of BTA. This ruling is favorable for the industry and NRG as it improves the U.S. EPA s ability to include alternatives to closed-loop cooling in its redraft of the Phase II 316(b) Rules. In the absence of federal regulations, some states in which NRG operates, such as California, Connecticut, Delaware and New York, are moving ahead with guidance for more stringent requirements for once-through cooled units which may have an impact on future operations.

Nuclear Waste The Obama administration has determined that Yucca Mountain, Nevada is not a workable option for a nuclear waste repository and will discontinue its program to construct a repository at the mountain in 2010. In order to meet the federal government s obligations to safely manage used nuclear fuel and radioactive waste under the U.S. Nuclear Waste Policy Act of 1982, the Department of Energy has announced the establishment of a blue ribbon commission to explore alternatives. Consistent with the U.S. 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 DOE including the fees to be paid by the owners for DOE s services. Since 1998, the DOE has been in default on its obligations to begin removing spent nuclear fuel and high-level radioactive waste from reactors.

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 U.S. Environmental Initiatives

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. 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 February 11, 2009, the U.S. Department of Justice acting at the request of the U.S. EPA commenced a lawsuit against Louisiana Generating, LLC in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. This is the same matter for which NOVs were issued to Louisiana

Generating, LLC on February 15, 2005, and on December 8, 2006. Further discussion on this matter can be found in Item 3 Legal Proceedings*, United States of America v. Louisiana Generating, LLC*.

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 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 Burton Island Old Ash Landfill, a historic captive landfill located at the Indian River facility. 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 is 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 matter.

Further details regarding the Company s Domestic Site Remediation obligations can be found in Item 14 Note 24, *Environmental Matters*, to the Consolidated Financial Statements.

International Environmental Matters

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

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

Schkopau, Germany 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 established a single national system for reporting of GHG, abatement actions and energy consumption and generation on July 1, 2008. This will underpin the Australian Emissions Trading Scheme, currently being debated in the Parliament. If it is passed into law, it is not expected to be effective until 2012. NRG may be able to mitigate its exposure to such law by getting free credits and/or contractually passing the obligation to buy credits on to its counterparties.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2010 through 2014 to meet NRG s environmental commitments will be approximately $0.9 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 U.S. EPA.

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

	Texas	Northeast	South Central	Total
	(In millions)			
2010	$	$ 230	$ 3	$ 233
2011		179	52	231
2012	6	45	108	159
2013	39	9	109	157
2014	50	4	68	122
Total	$ 95	$ 467	$ 340	$ 902

This estimate reflects the recent announcement to retrofit only Unit 4 at the Indian River Generating Station and shifts in the timing of other projects to reflect anticipated issuance dates for revised regulations.

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 regions 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.

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. The Company also routinely posts press releases, presentations, webcasts, and other information regarding the Company on the Company s website.

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 it 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. 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 and, depending upon the then-current gas commodity pricing, these purchases can be at higher prices than can be recovered under the Company s contracts. NRG s financial returns from its South Central region could be negatively impacted for a limited period if the rural cooperatives significantly grow their customer base during the remaining terms of these contracts prior to the expiration of half of the cooperative contracts in 2014. In addition, NRG has other obligations to supply power to load serving entities and, at times, NRG s load obligations may exceed its available generation and long-term purchases thus requiring the Company to purchase energy at market prices.

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.

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 ASC-815, *Derivatives and Hedging*, or ASC 815, 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.

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 development, 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 developing or constructing new generation facilities, improving its existing facilities and adding environmental controls to its existing facilities. The development, 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;
- performance risks; and
- unsuccessful partnering relationships.

In addition, NINA, the Company s 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 is subject to these and to additional risks, including delays in receiving or failure to receive commitments under the DOE s loan guaranty program and the inability to sell down NINA s interest in the STP expansion as the project develops.

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. In addition, the Company s nuclear development initiatives are an integral part of the Company s overall low or no carbon growth initiatives and the inability of the Company to maintain significant involvement in new nuclear development may result in the Company s inability to successfully implement the Company s other growth initiatives. 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.

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.

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 the Company s 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 or which complement the Company s industry. The acquisition of 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, the ability to retain customers and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, the Company s acquisitions may not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

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

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

Public utilities under the 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 U.S. 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, the Company s business prospects and financial results could be negatively impacted.

Furthermore, Congress is currently considering legislative proposals that would significantly increase the regulation of over-the-counter derivatives including those related to energy commodities, through the amendment of the Commodity Exchange Act. While NRG cannot predict at this time the outcome of any of the legislative efforts, many of the proposals generally contemplate mandatory clearing of such derivatives through clearing organizations and the increased standardization of contracts, products, and collateral requirements. Such changes could negatively impact NRG s ability to hedge its portfolio in an efficient, cost-effective manner, and, among other things, may limit NRG s ability to utilize liens as collateral. In addition, certain proposals seek to limit the proprietary trading activity of the banking institutions. Such changes may also result in a decrease in liquidity in the commodity markets.

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 U.S. Nuclear Waste Policy Act of 1982 to accept and dispose of STP s spent nuclear fuel. See also *Environmental Matters U.S. Federal Environmental Initiatives Nuclear Waste* in Item 1 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 U.S. to be collectively responsible for retrospective secondary insurance premiums for liability to the public arising from nuclear incidents resulting in claims in excess of the required primary insurance coverage amount of $300 million per reactor. The Price-Anderson Act only covers nuclear liability associated with any accident in the course of operation of the nuclear reactor, transportation of nuclear fuel to the reactor site, in the storage of nuclear fuel and waste at the reactor site and the transportation of the spent nuclear fuel and nuclear waste from the nuclear reactor. All other non-nuclear liabilities are not covered. Any substantial retrospective premiums imposed under the Price-Anderson Act or losses not covered by insurance could have a material adverse effect on NRG s financial condition, results of operations or cash flows.

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

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

Environmental laws and regulations have generally become more stringent over time, and the Company expects this trend to continue. Regulations currently under revision by U.S. EPA, including CAIR, MACT standards to control Mercury or acid gases 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.

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. In addition, GHG emissions from power plants will be subject to existing sections of the CAA including PSD/NSR and Title V permitting, at some point after the Light Duty Vehicle Greenhouse Gas Emissions Standards take effect. Implementation practices under the PSD/NSR requirements will determine the extent to which power plant operations are affected over time In 2009, in the course of producing approximately 71 million MWh of electricity, NRG s power plants emitted 59 million tonnes of CO_2 of which 53 million tonnes were emitted in the U.S., 3 million tonnes in Germany and 3 million tonnes in Australia.

Further 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 extent to which mitigation is required, 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 53 million tonnes of CO_2 emitted by NRG in the U.S. in 2009, approximately 8 million tonnes were emitted from the Company s generating units in Connecticut, Delaware, Maryland, Massachusetts, and New York that are subject to RGGI which started in 2009. While 2009 through 2011 CO_2 allowance prices have remained low, the impact of RGGI on future 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.

Hazards customary to the power production industry include the potential for unusual weather conditions, which could affect fuel pricing and availability, the Company s route to market or access to customers, i.e. transmission and distribution lines, or critical plant assets. To the extent that climate change contributes to the frequency or intensity of weather related events, NRG s operations and planning process could be impacted.

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, 2009, approximately 63% of NRG s employees at its U.S. generation plants were covered by collective bargaining agreements. In the event that the Company s union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, NRG would be responsible for procuring replacement labor or the Company could experience reduced power generation or outages. NRG s ability to procure such labor is uncertain. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on the Company s business, financial condition, results of operations and cash flow. In addition, a number of the Company s employees at NRG s plants are close to retirement. The Company s 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 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 ASC-350, *Intangibles-Goodwill and Others*; or ASC 305, 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.

Volatile power supply costs and demand for power could adversely affect the financial performance of NRG s retail business.

Although NRG has begun the process of becoming the primary provider of Reliant Energy s supply requirements, Reliant Energy presently purchases a significant portion of its supply requirements from third parties. As a result, Reliant Energy s financial performance depends on its ability to obtain adequate supplies of electric generation from third parties at prices below the prices it charges its customers. Consequently, the Company s earnings and cash flows could be adversely affected in any period in which Reliant Energy s power supply costs rise at a greater rate than the rates it charges to customers. The price of power supply purchases associated with Reliant Energy s energy commitments can be different than that reflected in the rates charged to customers due to, among other factors:

varying supply procurement contracts used and the timing of entering into related contracts;

subsequent changes in the overall price of natural gas;

daily, monthly or seasonal fluctuations in the price of natural gas relative to the 12-month forward prices;

transmission constraints and the Company s ability to move power to its customers; and

changes in market heat rate (i.e., the relationship between power and natural gas prices).

The Company s earnings and cash flows could also be adversely affected in any period in which the demand for power significantly varies from the forecasted supply, which could occur due to, among other factors, weather events, competition and economic conditions.

NRG s Texas retail business depends on the Electric Reliability Council of Texas, or ERCOT, to communicate operating and system information in a timely and accurate manner. Information that is not timely or accurate can have an impact on the Company s current and future reported financial results.

ERCOT communicates information relating to a customer s choice of retail electric provider and other data needed for servicing the customer accounts of the Company s retail electric providers. Any failure to perform these tasks will result in delays and other problems in enrolling, switching and billing customers. Information that is not timely or accurate may adversely impact the Company s ability to serve load in the optimum manner.

NRG s Texas retail business could be liable for a share of the payment defaults of other market participants.

If a market participant defaults on its payment obligations to an ISO, the Company, together with other market participants, are liable for a portion of the default obligation that is not otherwise covered by the defaulting market participant. Each ISO establishes credit requirements applicable to market participants and the basis for allocating payment default amounts to market participants. In ERCOT, the allocation is based on share of the total load.

Significant events beyond the Company s control, such as hurricanes and other weather-related problems or acts of terrorism, could cause a loss of load and customers and thus have a material adverse effect on the Company s Texas retail business.

The uncertainty associated with events beyond the Company s control, such as significant weather events and the risk of future terrorist activity, could cause a loss of load and customers and may affect the Company s results of operations and financial condition in unpredictable ways. In addition, significant weather events or terrorist actions could damage or shut down the power transmission and distribution facilities upon which the retail business is dependent. Power supply may be sold at a loss if these events cause a significant loss of retail customer load.

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;
- Volatile power supply costs and demand for power;
- 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, wind and solar 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;

NRG s ability to implement its *FOR*NRG strategy of increasing the return on invested capital through operational performance improvements and a range of initiatives at plants and corporate offices to reduce costs or generate revenues;

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

Reliant Energy s ability to maintain market share;

NRG s ability to successfully evaluate investments in new business and growth initiatives; and

NRG s ability to successfully integrate and manage any acquired businesses.

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, 2009. 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, 2009. 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	2,490	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
Cedar Bayou 4, Baytown, Texas	ERCOT	50.0	260	Natural Gas
T. H. Wharton, Houston, Texas	ERCOT	100.0	1,025	Natural Gas
W. A. Parish, Thompsons, Texas	ERCOT	100.0	1,175	Natural Gas
S. R. Bertron, Deer Park, Texas	ERCOT	100.0	765	Natural Gas
Greens Bayou, Houston, Texas	ERCOT	100.0	760	Natural Gas
San Jacinto, LaPorte, Texas	ERCOT	100.0	160	Natural Gas
Elbow Creek Wind Farm, Howard County, Texas	ERCOT	100.0	120	Wind
Langford Wind Farm, Christoval, Texas	ERCOT	100.0	150	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	135	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
South Central Region:				
Big Cajun II, New Roads, Louisiana[b]	SERC-Entergy	86.0	1,495	Coal
Bayou Cove, Jennings, Louisiana	SERC-Entergy	100.0	300	Natural Gas
Big Cajun I, Jarreau, Louisiana	SERC-Entergy	100.0	430	Natural Gas/Oil
Rockford I, Illinois	PJM	100.0	300	Natural Gas

Rockford II, Illinois	PJM	100.0	155	Natural Gas
Sterlington, Louisiana	SERC-Entergy	100.0	175	Natural Gas
West Region:				
Blythe, Blythe, California	CAISO	100.0	20	Solar
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

(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%

The following table summarizes NRG s thermal facilities as of December 31, 2009:

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	103 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, its Reliant Energy offices and call centers, and various other office space. In addition, NRG is constructing office space under a newly signed lease, to combine the Company s Texas region administration offices and Reliant Energy s offices.

Item 3 Legal Proceedings

***City of San Antonio, Texas, acting by and through the City Public Service Board of San Antonio, a Texas municipal utility v. Toshiba Corporation; NRG Energy, Inc.; Nuclear Innovation North America, LLC; NINA Texas 3 LLC; and NINA Texas 4 LLC (as amended), 37th Judicial District Court, Bexar County, TX, Case #2009CL19492* (filed December 6, 2009)** The original December 6, 2009, complaint against two Nuclear Innovation North America, or NINA, entities asked the court to declare the rights, obligations, and remedies of the parties pursuant to the 1997 and 2007 agreements between the parties should CPS unilaterally withdraw from the proposed

South Texas Project Units 3 and 4, or the STP Units 3 and 4 Project. On December 23, 2009, CPS amended its original December 6 complaint adding NRG, Toshiba Corporation, and NINA LLC as defendants and not only continued to request that the Court declare the rights, obligations, and remedies of the parties under the two operative governing agreements, but also sought $32 billion in damages. CPS amended its complaint again on December 28, 2009.

On January 6, 2010, CPS amended its complaint for the third time. In addition to requesting immediate injunctive relief, the amended complaint alleges that NRG, Toshiba, and NINA have been involved in a conspiracy to defraud CPS, that they purposefully misled CPS in inducing it to be a partner in the STP Units 3 and 4 Project, that they maliciously interfered with CPS contracts and business relationships, and that they willfully disparaged CPS. It sought declarations that: (i) owner consensus is required for all development decisions; (ii) there is a right to voluntary withdrawal, after which no further obligations accrue but undiluted ownership continues; (iii) both the partition waiver and forfeiture provisions are unenforceable against CPS under Texas law if they did apply; and (iv) CPS is not currently in breach. In addition, CPS sought relief among the following alternatives: partition by sale; an order forcing NRG and NINA to buy CPS undiluted share at an independent valuation; an order requiring NRG to compensate CPS $350 million investment and fair value for the site; an order granting CPS twelve months following withdrawal to sell its stake in the project; or an order that no further development take place without consensus of all project owners. The case was removed and remanded to and from federal court on three separate occasions. On January 19, 2010, CPS dismissed Toshiba from the lawsuit.

The parties agreed to a January 25, 2010, phased trial wherein all other claims would be reserved for an undetermined future phase II date and a trial would go forward in phase I only on CPS request for declaratory relief to determine the respective rights, obligations, and remedies of the parties under the two operative governing agreements should CPS withdraw from the STP Units 3 and 4 Project. On January 25,2010, the parties argued the NINA entities and NRG s Motion for Summary Judgment which was denied on January 26, 2010. After a two-day trial, the court issued its ruling on January 29, 2010, making a number of findings. It ruled that as of January 29, CPS and NINA were each 50% equity owners as tenants in common under Texas law in the STP Units 3 and 4 Project. The court found that while a withdrawing party does not forfeit its 50% interest upon a withdrawal, the governing agreements are silent as to whether that withdrawing party can recoup its sunk costs upon withdrawal. Finally, the court noted that for CPS to remain a 50% equity owner, it must pay all appropriate costs. Failure to do so, the court determined, would result in a complete loss of CPS equity share.

On February 17, 2010, an agreement in principle was reached with CPS for NINA to acquire a controlling interest in the STP Units 3 and 4 Project through a settlement of all pending litigation between the parties. As part of that agreement, all litigation would be dismissed with prejudice, including all Phase II claims, thereby ending this matter. For further discussion, see Item 1, *Nuclear Development.* The parties continue to negotiate terms regarding final documentation of the agreement in principle.

Public Utilities Commission of the State of California v. Long-Term Sellers of Long-Term Contracts to the California Department of Water Resources*, *FERC Docket No. EL02-60 et al. 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 U.S. Court of Appeals for the 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 *Mobile-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 U.S. 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: (i) that the *Mobile-Sierra* public interest standard of review applied to contracts made under a seller s market-based rate authority; (ii) that the public interest bar required to set aside a contract remains a very high one to overcome; and (iii) that the *Mobile-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 U.S. Supreme Court affirmed the Ninth Circuit s decision agreeing that the case should be remanded to the FERC to clarify the 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 U.S. 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 U.S. Supreme Court did not address in its June 26, 2008, decision; whether the *Mobile-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 that 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 U.S. Supreme Court s June 26, 2008 decision. On December 15, 2008, WCP and the other seller-defendants filed with the FERC a Motion for 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.

On January 14, 2010, the U.S. Supreme Court issued its decision in an unrelated proceeding involving the *Mobile-Sierra* doctrine that will affect the standard of review applied to the CDWR contract on remand before the FERC. In *NRG Power Marketing v. Maine Public Utilities Commission*, the Supreme Court held by an 8 to 1 margin that the *Mobile-Sierra* presumption regarding the reasonableness of contract rates does not depend on the identity of the complainant who seeks a FERC investigation/refund. The Supreme Court proceeding arose following an appeal by the Attorneys General of the State of Connecticut and of the Commonwealth of Massachusetts regarding the settlement establishing the New England Forward Capacity Market. The settlement, filed with the FERC on March 7, 2006, provides for interim capacity transition payments for all generators in New England for the period from December 1, 2006, through May 31, 2010, and for the Forward Capacity Market auction rates thereafter. The Court of Appeals for the DC Circuit, or DC Circuit, had rejected all substantive challenges to the settlement, but had sustained one procedural argument relating to the applicability of the *Mobile-Sierra* doctrine to third parties. The Supreme Court reversed the DC Circuit on this point, and remanded the case for further consideration of whether the transition payments and auction rates qualify as contract rates.

***United States of America v. Louisiana Generating, LLC., U.S.D.C Middle District of Louisiana,* Civil Action No. 09-100-RET-CN (filed February 11, 2009)** The U.S. Department of Justice acting at the request of the U.S. EPA commenced a lawsuit against Louisiana Generating, LLC in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. This is the same matter for which NOVs were issued to Louisiana Generating, LLC on February 15, 2005, and on December 8, 2006. Specifically, it is alleged that in the late 1990 s, several years prior to NRG s acquisition of the Big Cajun II power plant from the Cajun Electric bankruptcy and several years prior to the NRG bankruptcy, modifications were made to Big Cajun II Units 1 and 2 by the prior owners without appropriate or adequate permits and without installing and employing the BACT to control emissions of nitrogen oxides and/or sulfur dioxides. The relief sought in the complaint includes a request for an injunction to: (i) preclude the operation of Units 1 and 2 except in accordance with the CAA; (ii) order the installation of BACT on Units 1 and 2 for each pollutant subject to regulation under the CAA; (iii) obtain all necessary permits for Units 1 and 2; (iv) order the surrender of emission allowances or credits; (v) conduct audits to determine if any additional modifications have been made which would require compliance with the CAA s Prevention of Significant Deterioration program; (vi) award to the Department of Justice its costs in prosecuting this litigation; and (vii) assess civil penalties of up to $27,500 per day for each CAA violation found to have occurred between January 31, 1997, and March 15, 2004, up to $32,500 for each CAA violation found to have occurred between March 15, 2004, and January 12, 2009, and up to $37,500 for each CAA violation found to have occurred after January 12, 2009.

On April 27, 2009, Louisiana Generating, LLC made several filings. It filed an objection in the Cajun Electric Cooperative Power, Inc. s bankruptcy proceeding in the U.S. Bankruptcy Court for the Middle District of Louisiana to seek to prevent the bankruptcy from closing. It also filed a complaint in the same bankruptcy proceeding in the same court seeking a judgment that: (i) it did not assume liability from Cajun Electric for any claims or other liabilities under environmental laws with respect to Big Cajun II that arose, or are based on activities that were undertaken, prior to the closing date of the acquisition; (ii) it is not otherwise the successor to Cajun Electric; and (iii) Cajun Electric and/or the Bankruptcy Trustee are exclusively liable for the violations alleged in the February 11, 2009 lawsuit to the extent that such claims are determined to have merit. On June 8, 2009, the parties filed a joint status report setting forth their views of the case and proposing a trial schedule. On June 18, 2009, Louisiana Generating, LLC filed a motion to bifurcate the Department of Justice lawsuit into separate liability and remedy phases, and on June 30, 2009, the Department of Justice filed its opposition. On August 24, 2009, Louisiana Generating, LLC filed a motion to dismiss this lawsuit, and on September 25, 2009, the

Department of Justice filed its opposition to the motion to dismiss. A new federal bankruptcy judge was appointed on October 9, 2009.

On February 18, 2010, the Louisiana Department of Environmental Quality, or LDEQ, filed a motion to intervene in the above lawsuit and a complaint against Louisiana Generating LLC for alleged violations of Louisiana s PSD regulations and Louisiana s Title V operating permit program. LDEQ seeks similar relief to that requested by the Department of Justice. Specifically, LDEQ seeks injunctive relief to: (i) preclude the operation of Units 1 and 2 except in accordance with the CAA; (ii) order the installation of BACT on Units 1 and 2 for each pollutant subject to regulation under the CAA; (iii) obtain all necessary permits for Units 1 and 2 pursuant to the requirements of PSD and the Louisiana Title V operating permits program; (iv) conduct audits to determine if any additional modifications have occurred which would require it to meet the requirements of PSD and report the Results of the audit to the LDEQ and EPA; (v) order the surrender of emission allowances or credits; (vi) take other appropriate actions to remedy, mitigate and offset the harm to public health and the environment caused by violations of the CAA; (vii) assess civil penalties; and (viii) award to the LDEQ its costs in prosecuting the litigation. On February 19, 2010, the district court granted LDEQ s motion to intervene.

***Hohl Industrial Services, Inc, v. Dunkirk Power LLC, et al; New York State Supreme Court, County of Chautauqua; Index No, Kl-2009-1510* (original complaint filed August 28, 2009, cross claims filed by CBEEC on February 17, 2010)** In 2005, NRG entered into a Consent Decree with the New York State Department of Environmental Conservation whereby it agreed to reduce certain emissions generated by its Huntley and Dunkirk power plants. Pursuant to the Consent Decree, on November 21, 2007, Clyde Bergemann EEC, or CBEEC, and NRG entered into a firm fixed price contract for the supply of equipment, material and services for six fabric filters for NRG s Dunkirk Electric Power Generating Station. Subsequent to contracting with NRG, CBEEC subcontracted with Hohl Industrial Services, Inc., or Hohl, to perform steel erection and equipment installation at Dunkirk.

On August 28, 2009, Hohl filed its original complaint against NRG, its subsidiary Dunkirk Power LLC, or Dunkirk Power, and CBEEC among others for claims of breach of contract, quantum meruit, unjust enrichment and foreclosure of mechanics liens. As part of CBEEC s contractual obligation to NRG, CBEEC agreed to defend, under a reservation of rights, NRG s interest in this lawsuit. CBEEC filed an answer to the above complaint on behalf of itself, NRG and Dunkirk Power on October 5, 2009. On December 16, 2009, CBEEC filed a Motion for Summary Judgment on behalf of itself, NRG, and Dunkirk Power, which has yet to be decided.

On February 1, 2010, NRG and Dunkirk Power filed a Motion for Leave to file an Amended Answer with Cross-Claims against CBEEC. NRG asserted breach of contract claims seeking liquidated damages for the delays caused by CBEEC. NRG also retained its own counsel to represent its interest in the cross-claims and reserved its rights to seek reimbursement from CBEEC. On February 17, 2010, CBEEC filed an Amended Answer with Affirmative Defenses, Counterclaims and Cross-Claims against NRG. CBEEC is seeking approximately $30 million alleging breach of contract, quantum meruit, unjust enrichment, and foreclosure of two mechanic s liens, as a result of alleged delays caused by NRG and Dunkirk Power. A court ordered hearing and settlement conference is scheduled for February 23, 2010.

Excess Mitigation Credits From January 2002 to April 2005, CenterPoint Energy applied excess mitigation credits, or EMCs, to its monthly charges to retail electric providers as ordered by the PUCT. The PUCT imposed these credits to facilitate the transition to competition in Texas, which had the effect of lowering the retail electric providers monthly charges payable to CenterPoint Energy. As indicated in its Petition for Review filed with the Supreme Court of Texas on June 2, 2008, CenterPoint Energy has claimed that the portion of those EMCs credited to Reliant Energy Retail Services, LLC, or RERS, a retail electric provider and NRG subsidiary acquired from RRI Energy Inc., or RRI, totaled $385 million for RERS s Price to Beat Customers. It is unclear what the actual number may be. Price to Beat was the rate RERS was required by state law to charge residential and small commercial customers that were transitioned to RERS from the incumbent integrated utility company commencing in 2002. In its original stranded cost case brought before the PUCT on March 31, 2004, CenterPoint Energy sought recovery of all EMCs that were credited to all retail electric providers, including RERS, and the PUCT ordered that relief in its Order on Rehearing in Docket No. 29526, on December 17, 2004. After an appeal to state district court, the court entered a final judgment on August 26, 2005, affirming the PUCT s order with regard to EMCs credited to RERS. Various parties filed appeals of that judgment with the Court of Appeals for the Third District of Texas with the first such appeal filed on the same date as the state district court judgment and the last such appeal filed on October 10, 2005. On April 17, 2008, the Court of Appeals for the Third District reversed the lower court s decision ruling that CenterPoint Energy s stranded cost recovery should exclude only EMCs credited to RERS for its Price to Beat customers. On June 2, 2008, CenterPoint Energy filed a Petition for Review with the Supreme Court of Texas and on June 19, 2009, the Court agreed to consider the CenterPoint Energy appeal as well as two related petitions for review filed by other entities. Oral argument occurred on October 6, 2009.

In November 2008, CenterPoint Energy and RRI, on behalf of itself and affiliates including RERS, agreed to suspend unexpired deadlines, if any, related to limitations periods that might exist for possible claims against REI and its affiliates if CenterPoint Energy is ultimately not allowed to include in its stranded cost calculation those EMCs previously credited to RERS. Regardless of the outcome of the Texas Supreme Court proceeding, NRG believes that any possible future CenterPoint Energy claim against RERS for EMCs credited to RERS would lack legal merit. No such claim has been filed.

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.

PART II

Item 4 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 the 3.625% Convertible Perpetual Preferred Stock.

NRG s common stock is listed on the New York Stock Exchange and has been assigned the symbol: NRG. The high and low sales prices, as well as the closing price for the Company s common stock on a per share basis for 2009 and 2008 are set forth below:

Common Stock Price	Fourth Quarter 2009	Third Quarter 2009	Second Quarter 2009	First Quarter 2009	Fourth Quarter 2008	Third Quarter 2008	Second Quarter 2008	First Quarter 2008
High	$ 29.18	$ 29.26	$ 25.96	$ 25.38	$ 25.40	$ 43.95	$ 45.78	$ 43.96
Low	22.82	21.94	16.50	15.19	14.39	22.20	38.36	34.56

Closing	$ 23.61	$ 28.19	$ 25.96	$ 17.60	$ 23.33	$ 24.75	$ 42.90	$ 38.99

NRG had 253,995,308 shares outstanding as of December 31, 2009, and as of February 17, 2010, there were 261,898,178 shares outstanding. As of February 17, 2010, there were 70,000 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, 2009, were as follows:

For the Year Ended December 31, 2009	Total Number of Shares Purchased		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs		Dollar Value of Shares that may be Purchased Under the 2009 Capital Allocation Plan
First quarter		$			$	330,000,000
Second quarter						330,000,000
Third quarter	8,919,100		28.01	8,919,100		250,002,565
Fourth quarter	10,386,400		24.05	10,386,400		
Total for 2009	19,305,500	$	25.88	19,305,500	$	

The Company s Capital Allocation Plan included the completion of the 2008 Capital Allocation Plan with the planned purchase of $30 million of common stock as well as the purchase of an additional $300 million in common stock under the previously announced 2009 Capital Allocation Plan. In July 2009, as part of the Company s 2009 Capital Allocation Program, NRG s Board of Directors approved an increase to the Company s previously authorized common share repurchases under its capital allocation plan from the existing $330 million to $500 million. The Company s repurchases during the quarters ended September 30, 2009, and December 31, 2009, were $250 million and $250 million, respectively. The Company s share repurchases are subject to market prices, financial restrictions under the Company s debt facilities, and as permitted by securities laws.

Securities Authorized for Issuance under Equity Compensation Plans

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))

Equity compensation plans approved by security holders	7,947,003	$	25.07	5,129,593
Equity compensation plans not approved by security holders			N/A	
Total	7,947,003	$	25.07	5,129,593

(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 5,129,593 and 6,798,074 shares of common stock remaining available for grants of awards under NRG s LTIP as of December 31, 2009 and 2008, 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. As of December 31, 2009, there were 418,468 shares of treasury stock reserved for issuance under the ESPP. In January 2010, 54,845 shares were issued to employees accounts from the treasury stock reserve for the ESPP.

Stock Performance Graph

The performance graph below compares NRG s cumulative total shareholder return on the Company s common stock for the period December 31, 2004, through December 31, 2009, 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. NRG s common stock trades 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 December 31, 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.

	Dec-2004	**Dec-2005**	**Dec-2006**	**Dec-2007**	**Dec-2008**	**Dec-2009**
NRG Energy, Inc.	$ 100.00	$ 130.71	$ 155.37	$ 240.44	$ 129.43	$ 130.98
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
UTY	$ 100.00	$ 118.43	$ 142.34	$ 169.34	$ 123.15	$ 135.51

Item 5 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 14 Note 4, *Discontinued Operations and Dispositions*, 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 14 and Item 6, *Management s Discussion and Analysis of Financial Condition and Results of Operations.*

	Year Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
	(In millions unless otherwise noted)				
Statement of income data:					
Total operating revenues	$ 8,952	$ 6,885	$ 5,989	$ 5,585	$ 2,400
Total operating costs and expenses	7,283	5,119	5,073	4,724	2,290
Income from continuing operations, net	941	1,053	556	539	68
Income from discontinued operations, net		172	17	78	16
Net income attributable to NRG Energy, Inc.	942	1,225	573	617	84
Common share data:					
Basic shares outstanding average	246	235	240	258	169
Diluted shares outstanding average	271	275	288	301	171
Shares outstanding end of year	254	234	237	245	161
Per share data:					
Income attributable to NRG from continuing operations basic	3.70	4.25	2.09	1.89	0.28
Income attributable to NRG from continuing operations diluted	3.44	3.80	1.90	1.76	0.28
Net income attributable to NRG basic	3.70	4.98	2.16	2.19	0.38
Net income attributable to NRG diluted	3.44	4.43	1.96	2.02	0.38
Book value	29.72	26.75	19.55	19.60	11.31
Business metrics:					
Cash flow from operations	$ 2,106	$ 1,479	$ 1,517	$ 408	$ 68
Liquidity position [(a)]	3,971	4,124	2,715	2,227	758
Ratio of earnings to fixed charges	3.27	3.65	2.24	2.36	1.57
Ratio of earnings to fixed charges and preference dividends	3.04	3.19	1.99	2.08	1.32
Return on equity	12.24%	17.20%	10.38%	10.85%	3.77%
Ratio of debt to total capitalization	43.49%	47.50%	55.58%	57.18%	44.91%
Balance sheet data:					
Current assets	$ 6,208	$ 8,492	$ 3,562	$ 3,083	$ 2,197
Current liabilities	3,762	6,581	2,277	2,032	1,357

Property, plant and equipment, net	11,564	11,545	11,320	11,546	2,559
Total assets	23,378	24,808	19,274	19,436	7,467
Long-term debt, including current maturities and capital leases	8,418	8,161	8,346	8,698	2,456
Total stockholders equity	$ 7,697	$ 7,123	$ 5,519	$ 5,686	$ 2,231

N/A Not applicable

(a) Liquidity position is determined as disclosed in Item 6, Liquidity and Capital Resources, Liquidity Position. It includes funds deposited by counterparties of $177 million and $754 million as of December 31, 2009 and 2008, respectively, which represents cash held as collateral from hedge counterparties in support of energy risk management activities. It is the Company s intention to limit the use of these funds for repayment of the related current liability for collateral received in support of energy risk management activities.

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

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In millions)				
Energy	$ 3,031	$ 4,519	$ 4,265	$ 3,155	$ 1,840
Capacity	1,030	1,359	1,196	1,516	563
Retail revenue	4,440				
Risk management activities	418	418	4	124	(292)
Contract amortization	(179)	278	242	628	9
Thermal	100	114	125	124	124
Hedge Reset				(129)	
Other	112	197	157	167	156
Total operating revenues	$ 8,952	$ 6,885	$ 5,989	$ 5,585	$ 2,400

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. Capacity revenues also included revenues from the settlement of financial instruments that qualify for cash flow hedge accounting treatment. 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.

Retail revenue, representing operating revenue of Reliant Energy, consists of revenues from retail electric sales to residential, small business, commercial, industrial and governmental/institutional customers, as well as revenues from the sale of excess supply into various markets in Texas.

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 dates 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. Also included is amortization of the intangible asset for net in-market C&I contracts that was established in connection with the acquisition of Reliant Energy.

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

Other revenue primarily consists of operations and maintenance fees, or O&M fees, construction management services, or CMA 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. CMA fees are earned where NRG provides certain management and oversight of construction projects pursuant to negotiated agreements such as for the GenConn and Cedar Bayou 4 construction projects. Ancillary services are comprised of the sale of energy-related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products.

Item 6 Management s Discussion and Analysis of Financial Condition and Results of Operations

In this discussion and analysis, the Company discusses and explains its financial condition and results of operations, including:

- 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, 2009, 2008 and 2007. 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:

- Executive Summary, including introduction and overview, business strategy, and the 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 beginning with an overview of the Company s results, followed by a more detailed review of those results by operating segment;
- Financial condition addressing credit ratings, liquidity position, sources and uses of cash, capital resources and requirements, commitments, and off-balance sheet arrangements; and
- Critical accounting policies which are most important to both the portrayal of the Company s financial condition and results of operations, and which require management s most difficult, subjective or complex judgment.

Executive Summary

Overview

NRG Energy, Inc., or NRG or the Company, is primarily a wholesale power generation company with a significant presence in major competitive power markets in the U.S., as well as a major retail electricity franchise in the ERCOT (Texas) market. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, the trading of energy, capacity and related products in the U.S. and select international markets, and the supply of electricity and energy services to retail electricity customers in the Texas market.

As of December 31, 2009, NRG had a total global generation portfolio of 187 active operating fossil fuel and nuclear generation units, at 44 power generation plants, with an aggregate generation capacity of approximately 24,115 MW, and approximately 400 MW under construction which includes partner interests of 200 MW. In addition to its fossil fuel plant ownership, NRG has ownership interests in operating renewable facilities with an aggregate generation capacity of 365 MW, consisting of three wind farms representing an aggregate generation capacity of 345 MW (which includes partner interest of 75 MW) and a solar facility with an aggregate generation capacity of 20 MW. Within the U.S., NRG has large and diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 23,110 MW of fossil fuel and nuclear generation capacity in 179 active generating units at 42 plants. The Company s power generation facilities are most heavily concentrated in Texas (approximately 11,340 MW, including 345 MW from three wind farms), the Northeast (approximately 7,015 MW), South Central (approximately 2,855 MW), and West (approximately 2,150 MW, including 20 MW from a solar farm) regions of the U.S., with approximately 115 MW of additional generation capacity from the Company s thermal assets. In addition, through certain foreign subsidiaries, NRG has investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity.

NRG s principal domestic power plants consist of a mix of natural gas-, coal-, oil-fired, nuclear and renewable facilities, representing approximately 46%, 32%, 16%, 5% and 1% of the Company s total domestic generation capacity, respectively. In addition, 9% 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 the Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s 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.

On May 1, 2009, NRG acquired Reliant Energy, which is the second largest electricity provider to Mass customers in Texas. Reliant Energy is also the largest electricity and energy services provider, based on load, to C&I customers in Texas. Based on metered locations, as of December 31, 2009, Reliant Energy had approximately 1.5 million Mass customers and approximately 0.1 million C&I customers. Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service.

NRG s Business Strategy

NRG s business strategy is intended to maximize shareholder value through production and the sale of safe, reliable and affordable power to its customers and in the markets served by the Company, while aggressively pursuing sustainable energy solutions for the future.

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; (iii) empowering retail customers with distinctive products and services that transform how they use, manage and value energy; (iv) engaging in a proactive capital allocation plan focused on achieving the regular return of capital to stockholders within the dictates of prudent balance sheet management; and (v) pursuit of selective acquisitions, joint ventures, divestitures and investments in energy-related new businesses and new technologies in order to enhance the Company s asset mix and competitive position in the its core markets, as well as increasing demand for sustainable energy lifestyles and combating climate change.

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 enable the Company to convert the challenges faced by the power industry in the coming years into opportunities for financial growth. 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 2.0 initiative, NRG will continue its companywide effort to focus on extracting value from its portfolio by improving plant performance, reducing costs and harnessing the Company s advantages of scale in the procurement of fuels and other commodities, parts and services, and in doing so improving the Company s ROIC.

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 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 in the execution of asset-based risk management, hedging, marketing and trading strategies within well-defined risk and liquidity guidelines. 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.

The Company also seeks to achieve synergies between the Company s retail and wholesale business in Texas through its complementary generation portfolio in the Texas region, thereby creating the potential for a more stable, reliable and competitive business that benefits Texas consumers. By backing Reliant Energy s load-serving requirements with NRG s generation and risk management practices, the need to sell and buy power from other financial institutions and intermediaries that trade in the ERCOT market may be reduced, resulting in reduced transaction costs, credit exposures, and collateral postings. In addition, with Reliant Energy s base of retail customers, NRG now has a customer interface with the scale that is important to the successful deployment of consumer facing energy technologies and services.

Finally, NRG remains focused on cash flow and maintaining appropriate levels of liquidity, debt and equity in order to ensure continued access, through all economic and financial cycles, to capital for investment, to enhance risk-adjusted returns and to provide flexibility in executing NRG s business strategy, including a regular return of capital to its debt and equity holders.

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, as well as clean coal and the retrofit of post-combustion carbon capture technologies. Primarily through the *Repowering*NRG and econrg initiatives, 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, with an emphasis on new capacity that is supported by long-term power sales agreements and financed with limited or non-recourse project financing, and the demonstration and deployment of green technologies. *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 in locations where the Company anticipates retiring certain existing units and adding new generation to meet growing demand in the Company s core markets. 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. NRG expects that these efforts will provide some or all of the following benefits: improved heat rates; lower delivered costs; expanded electricity production capability; 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 GHG emissions or can be equipped to capture and sequester GHG emissions. In addition, several of the Company s original *Repowering*NRG projects or projects commenced under that initiative since its inception may qualify for financial support under the infrastructure financing component of the American Recovery and Reinvestment Act as well as other government incentive packages. NRG has several applications pending or contemplated.

New Businesses and New Technology NRG is focused on the development and investment in energy-related new businesses and new technologies, including low or no GHG emitting energy generating sources, such as nuclear, wind, solar thermal, and photovoltaic, as well as other endeavors where the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company, such as smart meters, electric vehicle ecosystems, and distributed clean solutions. The Company has made a series of recent advancements in these initiatives, including: (i) the acquisition of Bluewater Wind, an offshore wind development company; (ii) the acquisition of Blythe Solar, the largest photovoltaic solar power facility in California; (iii) the commercial operation of the Langford Wind Farm, the Company s third wind farm to be brought online; (iv) a partnership between Reliant Energy and the City of Houston and a partnership between Reliant Energy and Nissan to make Houston, Texas a launch city for the use of electric vehicles; and (v) the use of smart meters for Reliant Energy customers. Furthermore, the Company, supported by the econrg initiative, intends to capitalize on the high growth opportunities presented by government-mandated renewable portfolio standards, tax incentives and loan guaranties for renewable energy projects, new technologies and expected future carbon regulation.

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 and initiatives. NRG Global Giving is designed to enhance respect for the community, which is one of NRG s core values. The Global Giving Program invests NRG s resources to strengthen the communities where NRG does business and seeks to make community investments in four focus areas: community and economic development, education, environment and human welfare.

Business Environment

General Industry Trends impacting the power industry include: (i) financial credit market availability; and (ii) increased regulatory and political scrutiny. The industry dynamics and external influences that will affect the Company and the power generation industry in 2010 and for the medium term include:

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.

Financial Credit Market Availability 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. During 2009, the nation s credit markets recovered to some extent although credit continued to be tight relative to years prior to 2008. As evidence of the markets improvement, in April 2009, GenConn Energy, a joint venture of NRG and the United Illuminating Company, closed on a $534 million project financing and NRG was able to issue $700 million of bonds in June 2009, with a 10-year maturity at a yield to maturity of 8.75%. In addition, NRG had arranged a Credit Sleeve Reimbursement Agreement, or CSRA, with Merrill Lynch to support Reliant Energy after closing the acquisition. NRG has a diversified liquidity program, with $3.8 billion in total liquidity as of December 31, 2009, 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 transacts with a diversified pool of counterparties and actively manages the Company s exposure to any single counterparty. See Part II, Item 6 *Liquidity and Capital Resources*, and Part II, Item 6a *Quantitative and Qualitative Disclosures about Market Risk* for a further discussion.

The addition of Reliant Energy to NRG s existing generation business may provide opportunities to match generation to load directly which should reduce hedging and credit costs that both businesses would incur if hedged separately. Reliant Energy, which expects to lock in its wholesale supply in order to secure its margin as load is contracted, should also benefit from having better access to nonstandard and longer term products necessary to meet load. NRG expects to continue hedging its wholesale production consistent with its prior practice, but now will benefit from having an additional outlet for its range of generation products.

Climate Change The U.S. signed the Copenhagen Accord, or the Accord, which sets the stage for a worldwide approach to this global issue. Under the Accord, the U.S. has committed to a 17% reduction from 2005 emission levels of GHGs by 2020. While Congress was unable to come to agreement on climate legislation in 2009, the subject continues to be a topic for consideration in 2010. Lack of legislation will prolong the uncertainty of the nature and timing of GHG requirements and their resulting impact on NRG.

Climate change efforts continued outside of the legislature. The RGGI cap-and-trade program, in which NRG s emissions of CO_2 were 8 million tonnes in 2009, ended its first year with low allowance prices, nearing the reserve floor. This trend is expected to continue in the short term while the region works through the recession and increased use of renewable energy. California continues to develop their program for 2012 implementation. In addition to regional efforts, the U.S. EPA moved forward with a finding that GHGs do pose a threat to public health and welfare and light duty tailpipe regulations. These efforts will ultimately trigger the application of existing GHG permitting requirements for new and modified stationary sources like power plants, although the effective date and specifics of implementation lack clarity. The impact to NRG is dependent on the timing and implementation of PSD/NSR and

Title V permit requirements with regard to GHGs and any future actions taken by the U.S. EPA.

In 2009, in the course of producing approximately 71 million MWh of electricity, NRG s power plants emitted 59 million tonnes of CO_2, of which 53 million tonnes were emitted in the U.S., 3 million tonnes in Germany and 3 million tonnes in Australia. The impact from legislation or 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. Additionally, NRG s current contracts with its South Central region s cooperative customers allows for the recovery of emission-based costs.

Environmental Regulatory Landscape A number of regulations that could significantly impact the power generation industry are in development or under review by the U.S. EPA: CAIR, MACT, NAAQS revisions, coal combustion wastes, once-through cooling, and GHG regulations. While most of these regulations have been considered for some time, they are expected to gain clarity in 2010 through 2011. The timing and stringency of these regulations will provide a framework for the retrofit of existing fossil plants and deployment of new, cleaner technologies in the next decade. The Company has included capital to meet anticipated CAIR Phase I and II, MACT standards for mercury, and the installation of Best Technology Available under the 316(b) Rule in the current estimated environmental capital expenditure. While the Company cannot predict the impact of future regulations and would likely face additional investments over time, these expenditures, combined with the Company s already existing air quality controls; use of Powder River Basin coal; closed cycle cooling; and dry ash handling systems, position NRG well to meet more stringent requirements.

Public Policy Support and Government Financial Incentives The economic crisis, a changing public policy environment, and the current political climate have led to a shift away from utility investment in traditional fossil-fueled coal and natural gas-fired capacity and towards investment in non-traditional capacity, including renewable technologies, demand-side resources and nuclear. Generous public support, in the form of tax credits, loan guarantees, depreciation tax benefits, renewable energy credits, or RECs, and various other state and local incentives, are now available to builders of renewable electric generation. State Renewable Portfolio Standards, or RPS, requirements are now on the books in 28 states requiring load-serving entities to eventually source large percentages of their supply requirements from renewable sources or by purchasing REC credits, and federal requirements may follow. Designers of capacity markets in the Northeast region have attempted to improve the position of demand side resources relative to peaking capacity by holding these resources to a less stringent deliverability standard. Finally, the threat of carbon policy has had a chilling effect on new fossil generation supply additions, while encouraging all zero-carbon sources. These developments are likely to increase the role of renewable energy in the next energy commodity cycle, driving changes in wholesale market dynamics as renewable market share rises.

Infrastructure Development In the recent recessionary environment, the U.S. has experienced a contraction in demand, led primarily by reduced industrial demand in the manufacturing, chemical and petrochemical industries. As a result of lower demand and a proliferation of new natural gas supply from shale gas reserves, near term gas and power markets have experienced lower prices thus causing delays and cancellations of new generation supply and transmission investments. The Company expects recovery from the recession could lead to demand recovery and a trending back toward normalized growth rates spurring the need for additional generation supply. The potential for future federal carbon legislation and more restrictive environmental regulations could cause a rebalancing of the generation sector with older less efficient coal plants risking retirement and new infrastructure capital being deployed into low carbon technology in the form of baseload nuclear, renewable energy projects, and high efficiency (quick start) natural gas units. Government sponsored subsidies in the form of cash grants, investment tax credits and loan guarantees along with improved environmental policy clarity will continue to be crucial to help finance additional generation investment.

Natural Gas Market The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants. Natural gas prices are driven by many variables including demand from industrial, residential; and electric sectors; productivity across natural gas supply basins; fixed and variable costs of natural gas production; changes in pipeline infrastructure, and the financial and hedging profile of natural gas consumers and producers. In 2009, domestic natural gas supply increased, while demand decreased in the wake of the recession, leading to a fall in natural gas prices when compared to 2008. The increase in natural gas supply was due to increased production from unconventional resources, particularly the shale basins, and from the low variable costs of extraction from these resources. The Company expects rebalancing of the natural gas market to continue, and a price recovery could be driven by supply cuts as producer hedges roll-off and variable costs rise above market prices.

	Average Natural Gas Price ($/MMbtu)		
	2009	**2008**	**2007**
Henry Hub	$ 3.92	$ 8.85	$ 6.94

Electricity Prices The price of electricity is a key determinant of the profitability of the Company s generation portfolio. In 2009, prices for electricity were lower than in 2008, affected by both lower prices for natural gas and lower electric demand due largely to the recession. As general economic conditions improve, NRG expects to see a similar recovery in electric demand. The following table summarizes average on-peak power prices for each of the major markets in which NRG operates for the years ended December 31, 2009, 2008 and 2007.

	Average on Peak Power Price ($/MWh)		
Region	**2009**	**2008**	**2007**
Texas	$ 35.43	$ 86.23	$ 60.98
Northeast	46.14	91.68	76.37
South Central	33.58	71.25	59.63
West	$ 40.10	$ 82.20	$ 66.46

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.

The deregulated retail energy business in ERCOT is a competitive business. In general, competition in the retail energy business is on the basis of price, service, brand image, product offerings, and market perceptions of creditworthiness. Reliant Energy sells electricity pursuant to fixed price or indexed products, and customers elect terms of service typically ranging from one month to five years. Reliant Energy s rates are market-based rates, and not subject to traditional cost-of-service regulation by the PUCT. Non-affiliated transmission and distribution service companies provide, on a non-discriminatory basis, the wires and metering services necessary to access customers.

Weather

Weather conditions in the different regions of the U.S. 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 14 Note 24, *Environmental Matters*, to the Consolidated Financial Statements and Item 1, *Business Environmental Matters,* section. NRG discusses details of its regulatory matters in Item 14 Note 23, *Regulatory Matters*, to the Consolidated Financial Statements and Item 1, *Business Environmental Matters,* section. NRG discusses details of its legal proceedings in Item 14 Note 22, *Commitments and Contingencies*, to these Consolidated Financial Statements. Some of this information is about costs that may be material to the Company s financial results.

NINA On December 30, 2009, NINA had received an estimate from TANE, the prime contractor, containing the overnight estimate of the EPC Cost. The estimate was approximately $11.5 billion for STP Units 3 and 4 with an opportunity to reduce cost subject to certain specification changes. Based on the estimate provided by TANE and the Company s internal assessments, NINA continues to believe that NRG s stated target of $9.8 billion or $3,229/kW based on 3,000 MW gross output is achievable. Cost reductions will be achieved through a combination of specification changes and the re-alignment of risks and responsibilities among key project stakeholders.

Owners Costs for the project, on an escalated basis, are estimated to total approximately $2.1 billion during the construction period. This is primarily comprised of the costs for NRG s agent STPNOC, owners contingency and the initial fuel load. Financing Costs are estimated to be approximately $1.5 billion during the construction period, and are comprised of the variables described above.

On February 17, 2010, an agreement in principle was reached with CPS for NINA to acquire a controlling interest in the project to construct STP Units 3 and 4 through a settlement of the litigation between the parties. As part of the agreement, NINA would increase its ownership in the STP Units 3 and 4 project from 50% to 92.375% and would assume full management control of the project. NINA would also pay $80 million to CPS, subject to receipt of a conditional DOE loan guarantee. The first $40 million would be promptly paid after receipt of the guarantee and the other half six months later. An additional $10 million would be donated by NRG over four years in annual payments of $2.5 million to the Residential Energy Assistance Partnership in San Antonio. As part of the agreement with CPS, all litigation would be dismissed with prejudice. The parties continue to negotiate terms regarding final documentation of the agreement in principle.

The agreement would enable the STP Unit 3 and 4 project expansion to move forward and allow NINA to continuing pursuing its application for a conditional loan guarantee from the DOE. If NINA is not successful in reaching a final agreement with CPS, obtaining a conditional loan guarantee, or selling down its interest in STP Units 3 and 4, there could be negative implications for the project that may result in a reassessment of the probability of success of the project and an impairment of the value of the capitalized assets for STP Units 3 and 4. An impairment would result in a permanent write-down of the $299 million of construction-in-progress capitalized through December 31, 2009, plus any amounts capitalized through the impairment date.

Impact of inflation on NRG s results

Unless discussed specifically in the relevant segment, for the years ended December 31, 2009, 2008 and 2007, 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. As part of the 2010 program, the Company will invest approximately $474 million in maintenance and environmental capital expenditures in the existing assets and $707 million 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 2010 the Company will offer its first lien lenders $430 million of its 2009 excess cash flow (as defined in the Senior Credit Facility) of which the Company made a prepayment of $200 million in December 2009.

Significant events during the year ended December 31, 2009

Results of Operations and Financial Condition

Acquisition of Reliant Energy On May 1, 2009, NRG acquired Reliant Energy, which consisted of the entire Texas electric retail business operation of RRI, for cash consideration of $360 million, net of cash acquired. During the eight months ended December 31, 2009, Reliant Energy added $4.4 billion in retail revenue and $3.5 billion in cost of sales to the Company s results. In addition, NRG incurred non-recurring acquisition-related transaction and integration costs which totaled $54 million for the eight months ended December 31, 2009.

Lower energy revenue Energy revenues decreased $1.5 billion as a result of reduced energy prices as well as lower generation. The reduced energy prices were caused by lower average natural gas prices of approximately 56%. The reduction in generation was driven by weakened demand for power due to the recessionary economy.

Lower capacity revenue Capacity revenue decreased $329 million as a result of a lower portion of baseload contracts in the Texas region containing a capacity component.

Higher selling, general and administrative The Company s total selling, general and administrative expense increased in 2009 by $231 million. For the eight months ended December 31, 2009, Reliant Energy selling, general and administrative expense totaled $203 million, including $61 million of bad debt expense. Also included in 2009 results was the non-recurring cost of the Exelon s exchange offer and proxy contest efforts of $31 million.

Liquidity position The Company s total liquidity, excluding collateral received, rose $430 million in 2009. Cash balances grew by $810 million since the end of 2008 as $2.1 billion of cash provided by operating activities exceeded cash used including $734 million of capital expenditures, $644 million in debt payments, $500 million in treasury share payments, and $427 million in business acquisitions offset by the proceeds from the sale of MIBRAG of $284 million and the proceeds from the issuance of debt of $892 million.

Purchase of treasury shares During 2009, the Company repurchased 19,305,500 shares of common stock under its capital allocation plan for a total of $500 million.

Preferred Stock conversion On March 16, 2009, all of the outstanding shares of the Company s 5.75% Preferred Stock were converted into common stock for $447 million. During 2009, a total of 265,870 shares of Company s 4% Preferred Stock were converted into common stock for $257 million.

Sale of MIBRAG In 2009, the Company sold its 50% ownership interest in MIBRAG, to a consortium of Severoćeské doly Chomutov, a member of the CEZ Group, and J&T Group. For its share, NRG received proceeds of $284 million, net of transaction costs and realized a $128 million gain on sale of the equity method investment.

Issuance of 2019 Senior Notes In June 2009, NRG completed the issuance of $700 million aggregate principal amount of 8.5% Senior Notes due 2019, or 2019 Senior Notes. The Company used a portion of the net proceeds of $678 million to facilitate the early termination of NRG s obligations pursuant to the CSRA Amendment, which became effective October 5, 2009.

Merrill Lynch Credit Sleeve Facility On May 1, 2009, NRG arranged with Merrill Lynch to provide continuing credit support to Reliant Energy after closing the acquisition. In connection with entering into a transitional credit sleeve facility, or CSRA, NRG contributed $200 million of cash to Reliant Energy. In conjunction with the CSRA, NRG Power Marketing LLC, or PML, and Reliant Energy Power Supply LLC, or REPS, modified or novated certain transactions with counterparties to transfer PML s in-the-money transactions to REPS and moved $522 million of cash collateral held by NRG to Merrill Lynch, thereby reducing Merrill Lynch s actual and contingent collateral supporting Reliant Energy out-of-money positions. Effective October 5, 2009, the Company then executed the CSRA Amendment. In connection with this transaction, the Company posted $366 million of cash collateral to Merrill Lynch and other counterparties, returned $53 million of counterparty collateral, issued $206 million of letters of credit, and received $45 million of counterparty collateral. In addition, Merrill Lynch returned $250 million of previously posted cash collateral, and released liens on $322 million of unrestricted cash held by Reliant Energy. Upon execution of the CSRA Amendment, the Company was required to post collateral for any net liability derivatives, and other static margin associated with supply for Reliant Energy.

GenConn LLC related financings In April 2009, NRG Connecticut Peaking LLC., a wholly-owned subsidiary of NRG, executed an equity bridge loan facility, or EBL, in the amount of $121.5 million from a syndicate of banks. The purpose of the EBL is to fund the Company s proportionate share of the project construction costs required to be contributed into GenConn. Also in April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a 7-year term loan facility, and also entered into a 5-year revolving working capital loan and letter of credit facility. The aggregate credit amount secured is $291 million, including $48 million for the revolving facility. In August 2009, GenConn began to draw under the secured financing to cover costs related to the Devon project and as of December 31, 2009, has drawn $48 million.

Other

NINA On February 24, 2009, NINA executed an EPC agreement with TANE to build the STP expansion. Concurrent with the execution of the EPC agreement, NINA entered into a $500 million credit facility with Toshiba to finance the cost of long-lead materials for STP Units 3 and 4.

Cedar Bayou Generating Station In June 2009, NRG and Optim Energy, LLC, or Optim Energy, completed construction and began commercial operation of a new natural gas-fueled combined cycle generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas. NRG and Optim Energy have a 50/50 undivided interest basis in the 520 MW generating plant. NRG is the operator of the plant and Optim Energy is acting as energy manager for Cedar Bayou unit 4. Cedar Bayou unit 4 is providing the Company a net capacity of 260 MW given NRG s 50% ownership.

Langford Wind Project In December 2009, NRG completed its Langford project, a wholly-owned 150 MW wind farm located in Tom Green, Irion, and Schleicher Counties, Texas. The Company funded and developed this wind farm which consists of 100 General Electric 1.5 MW wind turbines. The project is eligible for a cash grant from the Department of Treasury and NRG has filed an application for an $84 million grant.

Acquisition and completion of Blythe Solar On November 20, 2009, NRG acquired through its wholly-owned subsidiary NRG Solar LLC, FSE Blythe 1, LLC, or Blythe Solar, from First Solar, Inc. On December 18, 2009, construction was completed and commercial operation began for the 20 MW utility-scale photovoltaic, or PV, solar facility located in Riverside County in southeastern California. The project is eligible for a cash grant from the Department of Treasury and NRG will file an application for an $18 million grant.

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. 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 recommended that NRG stockholders not tender their shares. In addition, on June 17, 2009, Exelon filed a Definitive Proxy Statement with the SEC presenting their proposals for the Company s 2009 Annual Meeting of Stockholders. NRG s Board of Directors recommended a vote against each of their proposals. On July 2, 2009, Exelon revised their unsolicited proposal and 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 recommended that NRG stockholders not tender their shares. On July 21, 2009, stockholders voted to re-elect all of the Company s director nominees to the NRG Board of Directors and rejected Exelon s proposals. On July 21, 2009, Exelon Corporation announced that in light of the vote results, effective immediately, it terminated its offer to acquire all of the outstanding shares of NRG. The total defense costs associated with Exelon s unsolicited proposal was approximately $39 million for the period October 1, 2008, through December 31, 2009, of which $31 million was for the year ended December 31, 2009.

Consolidated Results of Operations

2009 compared to 2008

The following table provides selected financial information for NRG Energy, Inc., for the years ended December 31, 2009, and 2008:

	Year Ended December 31, 2009	2008	Change%
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 3,031	$ 4,519	(33)%
Capacity revenue	1,030	1,359	(24)
Retail revenue	4,440		N/A
Risk management activities	418	418	
Contract amortization	(179)	278	(164)
Thermal revenue	100	114	(12)
Other revenues	112	197	(43)
Total operating revenues	8,952	6,885	30
Operating Costs and Expenses			
Cost of sales	4,524	2,641	71
Risk management activities	(338)		N/A
Other cost of operations	1,137	957	19
Total cost of operations	5,323	3,598	48
Depreciation and amortization	818	649	26
Selling, general and administrative	550	319	72
Acquisition-related transaction and integration costs	54		N/A
Development costs	48	46	4
Total operating costs and expenses	6,793	4,612	47
Operating Income	2,159	2,273	(5)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	41	59	(31)
Gains on sales of equity method investments	128		N/A
Other (loss)/income, net	(5)	17	(129)
Refinancing expenses	(20)		N/A
Interest expense	(634)	(583)	9

Total other expenses		(490)		(507)	(3)
Income from Continuing Operations before income tax expense		1,669		1,766	(5)
Income tax expense		728		713	2
Income from Continuing Operations		941		1,053	(9)
Income from discontinued operations, net of income tax expense				172	(100)
Net Income	$	941	$	1,225	(23)
Less: Net loss attributable to noncontrolling interest		(1)			N/A
Net income attributable to NRG Energy, Inc.	$	942	$	1,225	(23)
Business Metrics					
Average natural gas price Henry Hub ($/MMbtu)		3.92		8.85	(56)%

N/A Not applicable

The table below represents the results of NRG excluding the impact of Reliant Energy during the year ended December 31, 2009:

	Year ended December 31, 2009			2008	
	Consolidated	Reliant Energy	Total excluding Reliant Energy	Consolidated	Change%
			(In millions)		
Operating Revenues					
Energy revenue	$ 3,031	$	$ 3,031	$ 4,519	(33)%
Capacity revenue	1,030		1,030	1,359	(24)
Retail revenue	4,440	4,440			N/A
Risk management activities	418		418	418	
Contract amortization	(179)	(258)	79	278	(72)
Thermal revenue	100		100	114	(12)
Other revenues	112		112	197	(43)
Total operating revenues	8,952	4,182	4,770	6,885	(31)
Operating Costs and Expenses					
Cost of sales	4,524	3,003	1,521	2,641	(42)
Risk management activities	(338)	(315)	(23)		N/A
Other operating costs	1,137	153	984	957	3
Total cost of operations	5,323	2,841	2,482	3,598	(31)
Depreciation and amortization	818	137	681	649	5
Selling, general and administrative	550	203	347	319	9
Acquisition-related transaction and integration costs	54		54		N/A
Development costs	48		48	46	4
Total operating costs and expenses	6,793	3,181	3,612	4,612	(22)
Operating Income	$ 2,159	$ 1,001	$ 1,158	$ 2,273	(49)%

Operating Revenues

Operating revenues, excluding risk management activities, increased $2.1 billion during the year ended December 31, 2009, compared to the same period in 2008.

> *Retail revenue* the acquisition of Reliant Energy contributed $4.4 billion of retail revenue during the eight months ended December 31, 2009. Retail revenue includes Mass revenues of $2.6 billion, C&I revenues of $1.6 billion, and supply management revenues of $251 million.

Energy revenue decreased $1.5 billion during the year ended December 31, 2009, compared to the same period in 2008:

Texas decreased by $431 million, with $253 million of the decrease driven by lower average realized energy prices, $116 million of the decrease driven by a reduction in generation, and a $62 million decrease in margin on MWh sold from purchased energy. The average realized energy price decreased by 9%, driven by a 45% decrease in merchant prices, offset by a 23% increase in contract prices. Lower merchant prices were driven by the combination of lower gas prices in 2009 and unusually high pricing events that occurred in 2008 that did not repeat in 2009. Generation decreased by 4% driven by a 9% decrease in coal plant generation. This decrease in generation was offset by a 12% increase in gas plant generation primarily from Cedar Bayou 4 gas plant, and generation from Elbow Creek and Langford wind farms, none of which were in operation in 2008. Coal plant generation was adversely affected by lower energy prices driven by a 56% decrease in average natural gas prices in combination with increased wind generation which shifted the coal unit s position in the bid stack, negatively affecting coal plant generation.

Northeast decreased by $575 million, with $295 million of the decrease driven by lower energy prices and $334 million of the decrease attributable to a reduction in generation offset by a $54 million increase from higher net contract revenue. Merchant energy prices were lower by an average of 40%. The lower energy prices reduced the Company s net cost incurred to meet obligations under load serving contracts in the PJM market. Generation decreased by 31%, with a 31% decrease in coal generation and a 31% decrease in oil and gas generation. Weakened demand for power combined with lower gas prices resulted in reduced merchant energy prices. Lower merchant energy prices combined with higher costs of production from the introduction of RGGI resulted in increased hours where the coal plants were uneconomical to dispatch. The decline in oil and gas generation is attributable to fewer reliability run hours at Norwalk plant and higher maintenance work at Arthur Kill.

South Central decreased by $118 million due to a $80 million decline in contract revenue, a $2 million decrease in merchant energy revenues and a $36 million decrease in margin on MWh sold from purchased energy. The contract revenue decrease was attributed to a 10% decrease in sales volumes and a $5.15 per MWh lower average realized price. The decline in contract energy price was driven by a $16 million decrease in fuel cost pass-through to the cooperatives reflecting an overall decline in natural gas prices. Also contributing to the decline in contract revenue was $60 million due to the expiration of a contract with a regional utility. The expiration of the contract allowed more energy to be sold into the merchant market, but at lower average prices resulting in a $2 million decline in revenue. Increased use of the region s tolled facility provided additional energy to the merchant market.

Intercompany energy revenue intercompany sales of $349 million by the Company s Texas region to Reliant Energy were eliminated in consolidation.

Capacity revenue decreased $329 million during the year ended December 31, 2009, compared to the same period in 2008:

Texas decreased by $300 million due to a lower proportion of baseload contracts which contain a capacity component.

Northeast decreased by $8 million due to lower capacity prices in the NYISO.

South Central increased by $36 million resulting primarily from a new capacity agreement.

Intercompany capacity revenue intercompany capacity revenue of $47 million by the Company s Texas region to Reliant Energy were eliminated in consolidation.

Contract amortization revenue decreased by $457 million in the year ended December 31, 2009, as compared to the same period in 2008. The decrease resulted from a reduction of $198 million in revenue from the Texas Genco acquisition due to the lower volume of contracted energy. Also reducing contract amortization revenue was the amortization expense of net in-market C&I contracts related to the Reliant Energy acquisition of $258 million.

Other revenues decreased by $85 million driven by $51 million in lower ancillary revenue, $51 million in lower emissions revenue, and a $18 million decrease in fuels trading. Lower ancillary revenue was driven by a lesser load on the power grid as opposed to 2008 and lower ancillary prices. Lower emissions revenue was driven by lower carbon financial instrument sales and a loss on emission allowance sales. These decreases were offset by the recognition of a $31 million non-cash gain related to settlement of a pre-existing in-the-money contract with Reliant Energy at the time of acquisition. Other revenue also included $3 million in intercompany ancillary services in 2009 by the Company s Texas region and Reliant Energy that were eliminated in consolidation.

Cost of Operations

Cost of operations, excluding risk management activities, increased $2.1 billion during the year ended December 31, 2009, compared to the same period in 2008 and increased as a percentage of revenues to 66% for 2009 as compared to 56% for 2008.

Cost of sales increased $1.9 billion during the year ended December 31, 2009, compared to the same period in 2008, and increased as a percentage of revenues to 53% for 2009 as compared to 41% for 2008 due to:

Retail Reliant Energy incurred $3 billion of cost of energy during the eight months ended December 31, 2009, which included $399 million of intercompany supply costs.

Texas cost of energy decreased $305 million due to lower natural gas, coal, purchased energy and ancillary services costs.

Fuel expense Natural gas costs decreased $281 million, reflecting a 56% decline in average natural gas per MMBtu prices offset by a 12% increase in gas-fired generation. Coal costs increased by $5 million driven by a $44 million increase from higher coal prices and a $9 million increase in higher transportation costs. These increases were offset by a $28 million decrease from lower coal volume resulting from reduced generation and a $15 million loss reserve related to a coal contract dispute in 2008.

Ancillary service expense Ancillary service costs decreased $44 million due to a decrease in purchased ancillary service costs incurred to meet contract obligations.

Northeast cost of energy decreased $295 million due to a $187 million reduction in natural gas and oil costs and a $129 million reduction in coal costs.

Fuel expense Natural gas and oil costs decreased due to 31% lower generation and 56% lower average natural gas prices.

Coal costs decreased primarily due to 31% lower coal generation.

RGGI expense These decreases were offset by a $22 million increase in costs related to RGGI which became effective in 2009.

South Central cost of energy decreased $90 million due to a $58 million decrease in purchased energy reflecting lower fuel costs associated with the region s tolled facility and lower market energy prices, a $15 million decrease in natural gas costs, an $11 million decrease in coal costs, and an $8 million decrease in transmission expense due to transmission line outages. The decrease in natural gas cost is attributable to a 30% decrease in owned gas generation and a 54% decrease in natural gas prices. The coal cost decreased due to a 6% decrease in generation offset by a 1% increase in price.

West cost of energy decreased $6 million due to a 29% decline in average natural gas per MMBtu prices offset by an 8% increase in natural gas consumption and a $3 million increase in fuel oil expense resulting from a write-down to market of fuel oil inventory no longer used in the production of energy.

Intercompany cost of energy intercompany purchases of $399 million by Reliant Energy from the Company s Texas region were eliminated in consolidation.

Other cost of operations increased $180 million during the year ended December 31, 2009, compared to the same period in 2008. Reliant Energy incurred $153 million which includes $98 million for customer service operations and $55 million for gross receipt tax on revenue. Further, property taxes increased by $14 million due to reduction in eligibility related to Empire Zone tax credits in New York. Plant maintenance expenses were relatively flat during the period, however these expenses decreased in Northeast region by $22 million offset by an increase of $11 million in West region, a $6 million increase in South Central region and a $3 million increase in Texas region. In addition, NRG incurred a $12 million asset write-down due to the expected cancellation of the Indian River Unit 3 air pollution control equipment project and the consequent write-off of previously incurred construction costs.

Risk Management Activities

Risk management activities include economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activities. Total derivative gains increased by $338 million during the year ended December 31, 2009, compared to the same period in 2008. The breakdown of changes by region follows:

	Year ended December 31, 2009 (In millions)							
	Reliant Energy	**Texas**	**Northeast**	**South Central**	**West**	**Thermal**	**Elimination**	**Total**
Net gains/(losses) on settled positions	$ (480)	$ 311	$ 377	$ (2)	$ (8)	$ 6	$	$ 204
Mark-to-market gains/(losses)	794	(110)	(40)	(90)		(2)		552
Total derivative gains/(losses) included in revenues and cost of operations	$ 314	$ 201	$ 337	$ (92)	$ (8)	$ 4	$	$ 756

The breakdown of gains and losses included in revenue and cost of operations by region are as follows:

	Year ended December 31, 2009 (In millions)							
	Reliant Energy	**Texas**	**Northeast**	**South Central**	**West**	**Thermal**	**Elimination**	**Total**
Net gains/(losses) on settled positions, or financial income in revenues	$	$ 330	$ 384	$ 7	$ (8)	$ 6	$ (11)	$ 708
Mark-to-market results in revenues								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges		(73)	(120)			(3)		(196)
Reversal of gain positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	(1)							(1)
Reversal of previously recognized unrealized		(65)	(34)	(58)				(157)

gains on settled positions related to trading activity								
Reversal of previously recognized unrealized gains due to the termination of positions related to the CSRA unwind		(24)						(24)
Net unrealized gains/(losses) on open positions related to economic hedges	1	80	50	(17)		1	(1)	114
Net unrealized losses on open positions related to trading activity		(20)	(3)	(3)				(26)
Subtotal mark-to-market results		(102)	(107)	(78)		(2)	(1)	(290)
Total derivative gains/(losses) included in revenues	$	$ 228	$ 277	$ (71)	$ (8)	$ 4	$ (12)	$ 418

	Year ended December 31, 2009					
	Reliant Energy	Texas	Northeast	South Central	Elimination	Total
	(In millions)					
Net gains/(losses) on settled positions, or financial expense in cost of operations	$ (480)	$ (19)	$ (7)	$ (9)	$ 11	$ (504)
Mark-to-market results in cost of operations						
Reversal of previously recognized unrealized losses on settled positions related to economic hedges		47	81			128
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	657					657
Reversal of previously recognized unrealized losses due to the termination of positions related to the CSRA unwind	104					104
Net unrealized gains/(losses) on open positions related to economic hedges	33	(55)	(14)	(12)	1	(47)
Subtotal mark-to-market results	794	(8)	67	(12)	1	842
Total derivative gains/(losses) included in cost of operations	$ 314	$ (27)	$ 60	$ (21)	$ 12	$ 338

The $114 million mark-to-market gain in revenue related to economic hedges consisted of a $217 million gain recognized in earnings from previously deferred amounts in other comprehensive income, or OCI, as the Company discontinued cash flow hedge accounting in the first quarter for certain 2009 transactions in Texas and New York due to lower expected generation, offset by a $103 million decrease in value in forward sales of electricity and fuel relating to economic hedges due to lower forward power and gas prices. The $47 million mark-to-market loss in expense related to economic hedges consisted of a $18 million decrease in value of forward purchases of electricity and fuel and a loss of $29 million resulting from discontinued Normal Purchase Normal Sale, or NPNS, designated coal purchases due to expected lower coal consumption and accordingly, the Company could not assert taking physical delivery of coal purchase transactions under NPNS designation.

Reliant Energy s loss positions were acquired as of May 1, 2009, and valued using forward prices on that date. The $656 million roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in revenues and cost of operations during the same period. The $104 million gain from the reversal of a loss was offset by a realized loss at the settled prices and are reflected in cost of operations during the same period.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy, 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 revenue and costs. During and prior to 2009, NRG hedged a portion of the Company s 2009 through 2013 generation. During 2009, the settled prices of electricity and natural gas decreased resulting in the recognition of realized gains while forward power and gas prices decreased resulting in the recognition of unrealized mark-to-market gains. During 2008, decreasing forward prices of electricity and natural gas resulted in recognition of unrealized mark-to-market gains while the settled prices for power and gas increased resulting in the recognition of realized losses.

In accordance with ASC 815-10-45-9, the following table represents the results of the Company s financial and physical trading of energy commodities for the years ended December 31, 2009, and 2008. The realized financial trading results and unrealized financial and physical trading results are included in the risk management activities above, while the realized physical trading results are included in energy revenue. The Company s trading activities are subject to limits in accordance with the Company s risk management policy.

	Year ended December 31, 2009	Year ended December 31, 2008
	(In millions)	
Trading gains/(losses)		
Realized	$ 216	$ 67
Unrealized	(183)	63
Total trading (losses)/gains	$ 33	$ 130

Depreciation and Amortization

NRG s depreciation and amortization expense increased by $169 million for the year ended December 31, 2009, compared to the same period in 2008. Reliant Energy s depreciation and amortization expense for the eight month period was $137 million principally for amortization of customer relationships. The balance of the increase was due to depreciation on the baghouse projects in western New York and the Elbow Creek project which came online in late 2008, and the Cedar Bayou 4 plant which came online in the second quarter 2009.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $231 million for the year ended December 31, 2009, compared to the same period in 2008 and increased as a percentage of revenues to 6% for 2009 from 5% for 2008. The increase was due to:

Reliant Energy s selling, general and administrative expense totaled $203 million, including $61 million of bad debt expense incurred during the eight months ended December 31, 2009.

Wage and benefits expense increased $19 million.

Consultant costs increased $12 million consisting of a rise in non-recurring costs related to Exelon s exchange offer and proxy contest efforts of $23 million offset by a decrease in other consulting costs of $11 million.

Acquisition-Related Transaction and Integration Costs

NRG incurred Reliant Energy acquisition-related transaction costs of $23 million and integration costs of $31 million for the year ended December 31, 2009.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates decreased by $18 million for the year ended December 31, 2009, compared to the same period in 2008. During 2009, the Company s share in Gladstone Power Station and MIBRAG decreased by $4 million and $16 million, respectively. These decreases were offset by the Company s share of NRG Saguaro, LLC earnings increasing $11 million in 2009 as compared to 2008. In addition, there was a $6 million decrease in Sherbino s mark-to-market unrealized loss as compared to 2008 as a result of a natural gas swap executed to hedge to future power generation.

Gain on Sale of Equity Method Investments and Other Income/(Loss), Net

NRG s gain on sale of equity method investments was $128 million for the year ended December 31, 2009. Other income/(loss), net decreased by $22 million for the year ended December 31, 2009, compared to the same period in 2008. The 2009 amounts include a $128 million gain on the sale of NRG s 50% ownership interest in MIBRAG and a $24 million realized loss on a forward contract for foreign currency executed to hedge the sale proceeds from the MIBRAG sale. In addition, interest income for 2009 was reduced by $17 million as compared to

2008 due to lower interest rates. Further in 2008, a $23 million impairment charge was incurred to restructure distressed investments in commercial paper.

Refinancing Expenses

In 2009, NRG incurred a $20 million expense associated with the unwind of CSRA with Merrill Lynch. There were no such expenses in 2008.

Interest Expense

NRG s interest expense increased by $51 million for the year ended December 31, 2009, compared to the same period in 2008. This increase was primarily due to a $32 million increase in fees incurred during the months of May through December of 2009 on the CSRA facility, a $34 million increase in interest expense as a result of the 2019 Senior Notes issued in June 2009, a $4 million increase related to ineffective portion of the interest rate cash flow hedges on the Company s Term Loan Facility and an $8 million increase in the amortization of deferred financing costs. These increases were offset by a $33 million decrease in interest expense on the Company s Term Loan Facility due to a decrease in the outstanding notional amount and lower interest rates related to the unhedged portion of Term Loan and fair value portion of Senior Notes.

Income Tax Expense

Income tax expense increased by $15 million for the year ended December 31, 2009, compared to 2008. The effective tax rate was 43.6% and 40.4% for the year ended December 31, 2009, and 2008, respectively.

	Year Ended December 31,	
	2009	**2008**
	(In millions except as otherwise stated)	
Income from continuing operations before income taxes	$ 1,669	$ 1,766
Tax at 35%	584	618
State taxes, net of federal benefit	23	74
Foreign operations	(53)	(10)
Subpart F taxable income		2
Valuation allowance	119	(12)
Expiration of capital losses	249	
Reversal of valuation allowance on expired capital losses	(249)	
Change in state effective tax rate	(5)	(11)
Foreign dividends and foreign earnings	33	32
Non-deductible interest	10	12
FIN 48 interest	9	8
Production tax credits	(10)	
Other	18	
Income tax expense	$ 728	$ 713
Effective income tax rate	43.6%	40.4%

The Company s effective tax rate differs from the U.S. statutory rate of 35% due to:

Valuation Allowance The Company generated capital losses in 2009 primarily due to the derivative contracts that are eligible for capital treatment for tax purposes. The valuation allowance is recorded primarily against capital loss carryforwards. This resulted in an increase of $127 million in income tax expense in 2009.

Tax Expense Reduction The Company recorded a lower federal and state tax expense of $35 million primarily due to lower pre-tax earnings.

Change in state effective tax rate The Company decreased its estimated effective tax rate to 3% due to increased operational activities within the state of Texas resulting from the acquisition of Reliant Energy. This resulted in a tax benefit of $5 million.

Foreign Operations The Company elected not to permanently reinvest its earnings from foreign operations in 2008. In 2009, the Company sold its investment in the MIBRAG facility for a book gain of $128 million and no tax gain which resulted in minimal tax due in the local jurisdiction.

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 ASC-740, *Income Taxes*, or ASC 740. 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.

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		(583)		(702)	(17)
Total other expenses		(507)		(627)	(19)
Income from Continuing Operations before income tax expense		1,766		933	89
Income tax expense		713		377	89
Income from Continuing Operations		1,053		556	89
Income from discontinued operations, net of income tax expense		172		17	N/A
Net Income		1,225		573	114
Less: Net loss attributable to noncontrolling interest					
Net income attributable to NRG Energy, Inc.	$	1,225	$	573	114
Business Metrics					
Average natural gas price Henry Hub ($/MMbtu)		8.85		6.94	28%

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

Texas increased $172 million, with $430 million of this increase driven by higher prices, offset by $42 million reduced generation and a $216 million decrease on net margin on MWh sold from market purchases. 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.

Northeast decreased $40 million, with $66 million reduced generation, a $38 million decrease from lower net contract revenue offset by a $64 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.

South Central increased $74 million, attributable to a $41 million increase caused by higher energy prices and a $33 million increase on net margin on MWh sold from market purchases. 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.

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

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

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.

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.

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 revenue 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.

Cost of Operations

Cost of operations excluding risk management activities, increased $220 million during the year ended December 31, 2008, compared to the same period in 2007 and remained flat as a percentage of revenues at 56% for 2008 and 2007.

Cost of energy increased $213 million during the year ended December 31, 2008, compared to the same period in 2007 and remained flat as a percentage of revenues at 41% for 2008 and 2007. 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.

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 as 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.

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.

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.

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:

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

Northeast decreased $3 million due to $18 million in lower operating and maintenance expenses resulting from less outage work at the Norwalk plants and Indian River plants. This decrease 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 the 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.

Risk Management Activities

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				
(In millions)	**Texas**	**Northeast**	**South Central**	**Thermal**	**Total**
			(In millions)		
Net (losses)/gains on settled positions, or financial income in 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 gain	$ 318	$ 85	$ 10	$ 5	$ 418
Total derivative gain included in revenues	318	85	10	5	418
Total derivative gain included in cost of operations	$	$	$	$	$

NRG s 2008 gain is comprised of $525 million of mark-to-market gains and a $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 or physical 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.

In accordance with ASC 815-10-45-9, the following table represents the results of the Company s financial and physical trading of energy commodities for the years ended December 31, 2008, and 2007. The realized financial trading results and unrealized financial and physical trading results are included in the risk management activities above, while the realized physical trading results are included in energy revenue. The Company s trading activities are subject to limits in accordance with the Company s risk management policy.

	Year ended December 31, 2008	Year ended December 31, 2007
	(In millions)	
Trading gains		
Realized	$ 67	$ 396
Unrealized	63	18
Total trading gains	$ 130	$ 414

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 I Wind Farm LLC, 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. The impairment charge resulted from a change in the Company s fair value assessment as a result of a public auction of the assets in the structured investment vehicle holding the investments; this auction was the first observable market participation since the structured investment vehicle became illiquid in 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.

Interest Expense

NRG s interest expense decreased by $119 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.

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 ASC 815, 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 40.4% for the years ended December 31, 2008, and 2007.

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In millions except as otherwise stated)	
Income from continuing operations before income taxes	$ 1,766	$ 933
Tax at 35%	618	327
State taxes, net of federal benefit	74	46
Foreign operations	(10)	(13)

Subpart F taxable income	2	
Valuation allowance	(12)	6
Change in state effective tax rate	(11)	
Change in local German effective tax rates		(29)
Foreign dividends and foreign earnings	32	26
Non-deductible interest	12	10
FIN 48 interest	8	
Other		4
Income tax expense	$ 713	$ 377
Effective income tax rate	40.4%	40.4%

The increase in income tax expense was primarily due to:

Increase in income pre-tax income increased by $833 million, with a corresponding increase of $336 million in income tax expense.

Permanent differences The Company s effective tax rate differs from the U.S. statutory rate of 35% due to:

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.

Non-deductible interest resulted in an additional income tax expense of $2 million in 2008 as compared to the same period in 2007.

Change in German tax rate as a result of revaluing the Company s deferred tax assets, income tax expense benefited by $29 million in 2007, with no comparable benefit in 2008.

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 the Company s 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.

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 ASC 740. 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. 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.

Results of Operations for Reliant Energy

Selected Income Statement Data

		Period Ended December 31, 2009[(a)] (In millions except otherwise noted)
Operating Revenues		
Mass revenues	$	2,597
Commercial and industrial revenues		1,592
Supply management revenues		251
Contract amortization		(258)
Total operating revenues		4,182
Operating Costs and Expenses		
Cost of energy (including risk management activities)		2,688
Other operating expenses		356
Depreciation and amortization		137
Operating Income	$	1,001
Electricity sales volume-GWh (in thousands):		
Mass		17,152
Commercial and Industrial [(b)]		20,915
Business Metrics		
Weighted average retail customers count (in thousands, metered locations)		
Mass		1,566
Commercial and Industrial [(b)]		68
Retail customers count (in thousands, metered locations)		
Mass		1,531
Commercial and Industrial [(b)]		66
Cooling Degree Days, or CDDs [(c)]		2,972
CDD s 30-year average		2,713
Heating Degree Days, or HDDs [(c)]		699
HDD s 30-year average		644

(a) For the period May 1, 2009, to December 31, 2009.

(b) Includes customers of the Texas General Land Office for whom the Company provides services.

(c) 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. The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Reliant Energy serves its customer base.

Year to date results

Operating Income

Operating income for the period ended December 31, 2009, was $1,001 million, which consisted of the following:

	Period Ended December 31, 2009	
Reliant Energy Operating Income:		
Mass revenues	$	2,597
Commercial and industrial revenues		1,592
Supply management revenues		251
Total retail revenues [(a)]		4,440
Retail cost of sales [(a)]		3,531
Total retail gross margin		909
Unrealized gains on energy derivatives		794
Contract amortization, net		(209)
Other operating expenses		(356)
Depreciation and amortization		(137)
Operating Income	$	1,001

(a) Amounts exclude unrealized gains/(losses) on energy derivatives and contract amortization.

Gross margin Reliant Energy s gross margin totaled $909 million, which was driven by strong margins in the Mass customer class and expanding margins in the C&I customer class. Volumes were higher due to greater customer usage driven by favorable weather as compared to the 30 year CDD and HDD averages, although partially offset by a decrease in number of customers during the period ended December 31, 2009. The Company acquired Reliant Energy customers on prices more consistent with 2008 costs of natural gas. Reliant Energy announced and enacted price reductions effective June 1 and July 1, 2009, that cumulatively lowered prices up to 20% for certain Mass customer classes. These reduced prices, relative to lower short-term supply costs, delivered strong margins. Competition, price reductions, and supply costs based on forward market prices, will likely drive lower margins in the future.

With the decline in natural gas prices, and the corresponding decline in the cost of energy supply, competitive retail prices have decreased relative to 2008. If supply costs continue to remain low, the Company expects competitive retail prices to continue their decline and to place pressure on unit margins. Additionally, the Company s customer counts have declined approximately by 6% since May 1, 2009.

Operating Revenues

Total operating revenues, including risk management activities, for the period ended December 31, 2009, were $4.2 billion and consisted of the following:

Mass revenues totaled $2.6 billion from retail electric sales to approximately 1.6 million end use customers in the Texas market. Revenue rates for acquired Reliant Energy customers were not consistent with the current costs of natural gas. These acquired revenue rates were reduced by Reliant Energy s announced and enacted price reductions effective June 1 and July 1, 2009 of up to 20% for certain Mass customer classes. Also, favorable weather, as compared to the 30-year CDD and HDD averages, caused an increase in customer usage. The higher prices, along with higher usage, were accompanied by a 5% decrease in the number of customers since May 1, 2009.

Commercial and industrial revenue C&I revenues for the period ended December 31, 2009, totaled $1.6 billion on volume sales of approximately 20,915 GWh. Variable rate contracts tied to the market price of natural gas accounted for approximately 73% of the contracted volumes as of December 31, 2009.

Contract amortization reduced operating revenues by $258 million resulting from net in-market C&I contracts acquired in the Reliant Energy acquisition. These contracts will be amortized over the life of the contracts with the longest contract term being approximately four years.

Supply management revenues totaled $251 million from the sale of excess supply into various markets in Texas.

Cost of Energy

Cost of energy for the period ended December 31, 2009, was $2.7 billion and consisted of the following:

Supply costs totaled $2 billion. The market cost of energy is significantly down due to the decline in natural gas prices since the same period last year. Also, favorable weather for the period, as compared to the 30-year CDD and HDD averages, caused an increase in purchased supply volumes at a relatively low cost.

Risk management activities Unrealized gains of $794 million on economic hedges relate to supply contracts that were recognized for the period ended December 2009, including $657 million of gains representing a roll-off of loss positions acquired at May 1, 2009, valued at forward prices on that date, reversal of losses of $104 million due to the termination of positions related to the CSRA unwind, and $33 million of gains that represent mark-to-market changes in the forward value of purchased electricity and gas. The $657 million gain from the roll-off of loss positions was offset by realized losses at the settled prices and higher cost of physical power which are reflected in the cost of operations during the same period. The $104 million gain from reversal of losses was offset by realized losses at the settled prices and is reflected in cost of operations during the same period.

Transmission and distribution charges totaled $964 million for the cost to transport the power from the generation sources to the end-use customers.

Financial settlements totaled $480 million resulting from financial settlement of energy related derivatives.

Contract amortization reduced cost of energy by $49 million, resulting from the net out-of-market supply contracts established at the acquisition date. These contracts will be amortized over the life of the contracts with the longest contract term being approximately seven years.

Other Operating Expenses

Other operating expenses for the period ended December 31, 2009, were $356 million, or 9% of Reliant Energy s total operating revenues. Other operating expenses consisted of the following:

Operations and maintenance expenses totaled $98 million. Theses expenses primarily consisted of the labor and external costs associated with customer activities, including the call center, billing, remittance processing and credit and collections, as well as the information technology costs associated with those activities.

Selling, general and administrative expenses totaled $142 million. These expenses primarily consisted of the costs of labor and external costs associated with advertising and other marketing activities, as well as human resources, community activities, legal, procurement, regulatory, accounting, internal audit and management, as well as facilities leases and other office expenses.

Gross receipts tax totaled $55 million or 1.3% of Mass and C&I revenues.

Bad debt expense totaled $61 million or 1.5% of Mass and C&I revenues which was driven by higher summer bills due to warmer weather and economic factors including unemployment in Dallas and Houston which is approaching national averages.

Results of Operations for Wholesale Power Generation Regions

Texas Region

2009 compared to 2008

The following table provides selected financial information for the Texas region for the years ended December 31, 2009, and 2008.

	Year Ended December 31,		Change
	2009	2008	%
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 2,439	$ 2,870	(15)%
Capacity revenue	193	493	(61)
Risk management activities	229	318	(28)
Contract amortization	57	255	(78)
Other revenues	28	90	(69)
Total operating revenues	2,946	4,026	(27)
Operating Costs and Expenses			
Cost of energy	963	1,240	(22)
Depreciation and amortization	472	451	5
Other operating expenses	671	650	3
Operating Income	$ 840	$ 1,685	(50)
MWh sold (in thousands)	47,259	47,806	(1)
MWh generated (in thousands)	44,993	46,937	(4)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 35.43	$ 86.23	(59)
Cooling Degree Days, or CDDs[(a)]	2,881	2,719	6
CDD s 30-year rolling average	2,647	2,647	
Heating Degree Days, or HDDs[(a)]	1,890	1,961	(4)%
HDD s 30-year rolling average	1,997	2,007	

(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 $845 million for the year ended December 31, 2009, compared to the same period in 2008, primarily due to:

Operating revenues decreased by $1.1 billion due to unfavorable energy and capacity revenue offset by a favorable impact of risk management activities.

Cost of energy decreased by $277 million driven by lower natural gas costs.

Operating Revenues

Total operating revenues decreased by $1.1 billion during the year ended December 31, 2009, compared to the same period in 2008, due to:

Energy revenue decreased $431 million due to:

Energy prices decreased by $253 million as the average realized merchant price was lower in 2009 due to the combination of lower gas prices and unusually high pricing events that occurred in 2008 but did not repeat in 2009. Higher MWh sold under merchant market was offset by lower merchant prices. The average realized energy price decreased by 9%, driven by a 45% decrease in merchant prices offset by a 23% increase in contract prices.

Generation decreased by 4% resulting in a $116 million decrease in sales volume. This decrease was driven by a 9% decrease in coal plant generation. This decrease was offset by a 12% increase in gas plant generation, and generation from the recently constructed Cedar Bayou 4 gas plant, the Elbow Creek wind farm, and the Langford wind farm which began commercial operations in June 2009, December 2008 and December 2009, respectively. Coal plant generation was adversely affected by lower energy prices driven by a 56% decrease in average natural gas prices in combination with increased wind generation in the region.

Margin on MWH sold from market purchases decreased by $62 million.

Capacity revenue decreased by $300 million due to a lower proportion of baseload contracts which contain a capacity component.

Risk management activities decreased by $89 million reflecting the difference between gains of $228 million recorded for the year ended December 31, 2009, compared to gains of $318 million during the same period in 2008. The $89 million decrease included $102 million of unrealized mark-to-market losses and $330 million in gains on settled transactions, or financial income, compared to $413 million in unrealized mark-to-market gains and $95 million in financial losses during the same period in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Contract amortization revenue resulting from the Texas Genco acquisition decreased by $198 million due to the reduced volume of contracted energy in 2009 as compared to 2008.

Other revenues decreased by $62 million primarily due to lower ancillary services revenue of $47 million provided to the market, and lower emissions credit revenue of $11 million.

Cost of Energy

Cost of energy decreased by $277 million during the year ended December 31, 2009, compared to the same period in 2008, due to:

Natural gas costs decreased by $281 million due to a 56% decline in average natural gas prices offset by a 12% increase in gas-fired generation.

Ancillary service costs decreased by $44 million due to a decrease in purchased ancillary services costs incurred to meet contract obligations.

These decreases were offset by:

Fuel risk management activities losses of $27 million were recorded for the year ended December 31, 2009. In the first quarter 2009, all NPNS coal contracts were discontinued and reclassified into mark-to-market accounting. The $27 million loss included $8 million of unrealized mark-to-market losses, largely associated with forward coal positions and $19 million in losses on settled transactions, or financial cost of energy. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Coal costs increased by $5 million driven by a $44 million increase in coal prices, offset by a $28 million decrease in coal volume. Additionally, an increase in higher transportation costs of $9 million was offset by a $15 million loss reserve related to a coal contract dispute in the first quarter of 2008, combined with a decrease of $3 million due to lower lignite royalties.

Cost Contract Amortization increased $19 million driven primarily by the reduction in amortization for out-of-the money coal contracts assumed in the acquisition of Texas Genco as coal is delivered under that contract.

Other Operating Expenses

Other operating expenses increased by $21 million during the year ended December 31, 2009, compared to the same period in 2008, driven by an increase of $14 million in general and administrative expense due to higher corporate allocations as a result of the change in method in allocating corporate costs as described in Item 14 Note 18, *Segment Reporting,* to the Consolidated Financial Statements. In addition, there was an increase of

$3 million for operations and maintenance costs, as well as an increase of $3 million in property and other taxes due to the recently constructed Cedar Bayou 4 and Elbow Creek facilities.

Depreciation and Amortization

Depreciation and amortization expense increased by $21 million for the year ended December 31, 2009, compared to the same period in 2008. This increase was the result of Cedar Bayou 4 and Elbow Creek reaching commercial operations in June 2009 and December 2008, respectively.

2008 compared to 2007

The following table provides selected financial information for the Texas 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	$ 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)	$ 86.23	$ 60.98	41
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:

Operating revenues increased by $739 million due to favorable risk management activities, energy and capacity revenues.

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

Operating Revenues

Total operating revenues 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 revenue increased by $172 million due to:

Energy prices increased by $430 million as the average realized merchant price was higher in 2008 due to the combination of higher gas prices and unusually high pricing events. The average realized energy price increased by 18%, driven by a 44% increase in merchant prices offset by a 16% decrease in contract prices.

Generation decreased by 2% resulting in a $42 million decline in sales volume. 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.

Margin on MWh sold from market purchases decreased by $216 million.

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

Other revenue 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 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 service costs 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 service costs.

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 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 and 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.

Northeast Region

2009 compared to 2008

The following table provides selected financial information for the Northeast region for the years ended December 31, 2009, and 2008:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 489	$ 1,064	(54)%
Capacity revenue	407	415	(2)
Risk management activities	277	85	N/A
Other revenues	28	66	(58)
Total operating revenues	1,201	1,630	(26)
Operating Costs and Expenses			
Cost of energy	341	695	(51)
Depreciation and amortization	118	109	8
Other operating expenses	399	392	2
Operating Income	$ 343	$ 434	(21)
MWh sold (in thousands)	9,220	13,349	(31)
MWh generated (in thousands)	9,220	13,349	(31)

Business Metrics					
Average on-peak market power prices ($/MWh)	$	46.14	$	91.68	(50)
Cooling Degree Days, or CDDs[a]		475		611	(22)
CDD s 30-year rolling average		537		537	
Heating Degree Days, or HDDs[a]		6,286		6,057	4
HDD s 30-year rolling average		6,262		6,294	(1)%

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

Operating Income

Operating income decreased by $91 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Operating revenues decreased by $429 million due to unfavorable energy revenues, other revenues and capacity revenues partially offset by a favorable impact from risk management activities.

Cost of energy decreased by $354 million due to lower generation and fuel prices.

Operating Revenues

Operating revenues decreased by $429 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Energy revenue decreased by $575 million due to:

Energy prices decreased by $295 million reflecting an average 40% decline in merchant energy prices.

Generation decreased by $334 million due to a 31% decrease in generation in 2009 compared to 2008, driven by a 31% decrease in coal generation and a 31% decrease in oil and gas generation. Coal generation declined 24%, or 1,471,726 MWhs, in western New York; 39%, or 1,503,975 MWhs, at Indian River; and 80%, or 476,537 MWh, at Somerset. The decline in generation at these plants is due to a combination of weakened demand for power, low gas prices and higher cost of production from the introduction of RGGI resulting in increased hours where the units were uneconomic to dispatch. The decline in oil and gas generation is attributable to fewer reliability run hours at the Norwalk plant and higher maintenance work at the Arthur Kill plant in 2009.

Margin on MWh sold from market purchases increased by $54 million driven by lower net costs incurred in meeting obligations under load serving contracts in the PJM market.

Other revenues decreased by $38 million due to $20 million from decreased activity in the trading of emission allowances and $17 million lower allocations of net physical gas sales.

Capacity revenue decreased by $8 million due to lower capacity cash flow revenue in New York in 2009.

These decreases were offset by:

Risk management activities gains of $277 million were recorded for the year ended December 31, 2009, compared to gains of $85 million during the same period in 2008. The $277 million gain included $107 million of unrealized mark-to-market losses and $384 million in gains on settled transactions, or financial income, compared to $82 million in unrealized mark-to-market gains and $3 million in financial gains during the same period in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Cost of Energy

Cost of energy decreased by $354 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Natural gas and oil costs decreased by $187 million, or 60%, due to 31% lower generation and 56% lower average natural gas prices.

Coal costs decreased by $129 million, or 35%, due to lower coal generation of 31% accounting for $111 million and lower prices accounting for $18 million. The lower prices are due to lower fuel transportation surcharges.

Fuel risk management activities gains of $60 million were recorded for the year ended December 31, 2009. In the first quarter 2009, all NPNS coal contracts were discontinued and reclassified to mark-to-market accounting. The $60 million gain included $67 million of unrealized mark-to-market gains, largely associated with forward coal positions and $7 million in losses on settled transactions, or financial cost of energy. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

These decreases were offset by:

Carbon emission expense increased by $22 million due to the January 1, 2009, implementation of RGGI and the recognition of carbon compliance cost under this program.

Depreciation and Amortization

Depreciation and amortization increased by $9 million primarily due to depreciation from the 2009 baghouse projects at NRG s Western New York coal plants.

Other Operating Expenses

Other operating expenses increased by $7 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Property taxes increased by $14 million due to lower Empire Zone tax benefits recognized in 2009 at the Oswego plant due to the plant receiving notice of decertification from the Empire Zone program in 2009 from the State of New York which decision is under appeal by the Company.

Write-down of assets increased by $12 million for the year ended December 31, 2009, compared to the same period in 2008. The write-down was due to the cancellation and subsequent write off of construction costs incurred through year end 2009 on the Indian River Unit 3 air pollution control equipment project. NRG and DNREC announced a proposed plan, subject to definitive documentation, that would shut down Unit 3 by December 31, 2013, and relieve NRG of the requirement to install this back-end control equipment. Unit 4 is not affected by this plan and construction on similar equipment continues with an expected in-service date of year-end 2011.

General and administrative expense increased by $2 million due to higher labor and employee benefit costs.

Development costs increased by $2 million due to increased repowering efforts at the Astoria plant and a biomass project at the Montville plant.

These increases was offset by:

Operations and maintenance expenses decreased by $22 million due to lower chemical spending and routine maintenance work as a result of lower generation and lower planned major maintenance work at the Huntley and Indian River plants.

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	Year Ended December 31, 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)	$ 91.68	$ 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 revenue increased by $13 million due to:

PJM capacity revenue 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 revenue 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 revenue 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 installed capacity 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 $64 million due to an average 6% rise in merchant 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.

Margin on MWh sold from market purchases decreased by $38 million driven by higher net costs incurred to service PJM contracts as a result of the increase in market energy prices.

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.

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 the region s New York City plants and higher property credits received in 2008 at the region s 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.

South Central Region

2009 compared to 2008

The following table provides selected financial information for the South Central region for the years ended December 31, 2009 and 2008:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 360	$ 478	(25)%
Capacity revenue	269	233	15
Risk management activities	(71)	10	N/A
Contract amortization	22	23	(4)
Other revenues	1	2	(50)
Total operating revenues	581	746	(22)
Operating Costs and Expenses			
Cost of energy	399	468	(15)
Depreciation and amortization	67	67	
Other operating expenses	109	111	(2)
Operating Income	$ 6	$ 100	(94)
MWh sold (in thousands)	12,144	12,447	(2)
MWh generated (in thousands)	10,398	11,148	(7)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 33.58	$ 71.25	(53)
Cooling Degree Days, or CDDs[(a)]	1,549	1,618	(4)
CDD s 30-year rolling average	1,548	1,547	
Heating Degree Days, or HDDs[(a)]	3,521	3,672	(4)
HDD s 30-year rolling average	3,604	3,623	(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 $94 million for the year ended December 31, 2009, compared to the same period in 2008 due to:

Operating revenues declined by $165 million as a result of decreases in energy revenue, risk management activities and other revenue. These decreases were offset by an increase in capacity revenue.

*Cost of energ*y declined by $69 million due to lower purchased energy, fuel and transmission costs, offset by higher fuel risk management activities.

Operating Revenues

Operating revenues decreased by $165 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Energy revenue decreased by $118 million due to a $80 million decline in contract revenue, a $2 million decrease in merchant energy revenue and a $36 million decrease in margin on MWh sold from market purchases. The contract revenue decrease was attributed to a 10% decrease in sales volumes and a $5.15 per MWh lower average realized price. The decline in contract energy price was driven by a $16 million decrease in fuel cost pass-through to the cooperatives reflecting an overall decline in natural gas prices. Also contributing to the decline in contract revenue was a $60 million decrease due to the expiration of a contract with a regional utility. The expiration of the contract allowed more energy to be sold into the merchant market, but at lower prices resulting in a $2 million decline in revenue.

Risk management activities losses of $71 million were recorded for the year ended December 31, 2009, compared to gains of $10 million during the same period in 2008. The $71 million loss included $78 million of unrealized mark-to-market losses offset by $7 million in gains on settled transactions, or financial income, compared to $26 million in unrealized mark-to-market gains offset by $16 million in financial losses during the same period in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

These decreases were offset by:

Capacity revenue grew by $36 million driven by a $40 million increase from new capacity agreements with regional utilities and a $5 million increase in capacity revenue contributed by the region s Rockford plants which dispatch into the PJM market, offset by reduced contract capacity revenue of $9 million.

Cost of Energy

Cost of energy is down by $69 million for the year ended December 31, 2009, compared to the same period in 2008, reflecting:

Purchased energy declined by $58 million while purchased capacity rose by $3 million. The lower purchased energy was driven by lower fuel costs associated with the region s tolled facility and lower market energy prices. The energy declines were offset by increased capacity payments of $3 million on tolled facilities.

Natural gas expense decreased by $15 million reflecting a 30% drop in owned gas generation and a 54% decline in gas prices. The region s gas facilities ran extensively to support transmission system stability following hurricane Gustav in September 2008.

Coal expense decreased $11 million as coal generation was down 6%, offset by a 1% increase in cost per ton.

Transmission expense declined by $8 million due to certain transmission line outages between electrical power regions which limited merchant energy volumes that would incur transmission costs as well as lower network interchange transmission costs associated with reduced contract customer energy volumes.

These decreases were offset by:

Fuel risk management activities losses of $21 million were recorded for the year ended December 31, 2009. In the first quarter 2009, all NPNS coal contracts were discontinued and reclassified into mark-to-market accounting. The $21 million loss included $12 million of unrealized mark-to-market losses largely associated with forward coal positions and $9 million in losses on settled transactions, or financial cost of energy. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Other Operating Expenses

Other operating expenses decreased by $2 million for the year ended December 31, 2009, compared to 2008, associated with:

General and administrative expense Corporate allocations declined by $8 million in 2009 versus the same period in 2008. Franchise tax expense grew by $2 million due to credits recorded in 2008 related to prior years.

Operating and maintenance expense Labor costs increased by $2 million because of higher benefit costs. Major maintenance rose by $2 million due to more extensive outage work performed at the Big Cajun II plant in 2009 compared to the same period in 2008.

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	$ 59.63	19
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 revenue increased by $74 million due to a $41 million increase in merchant energy revenues and a $33 million increase in margin on MWh sold from market purchases. A decline in contract sales of 577 thousand MWh allowed for increased sales into the merchant market at higher prices. 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 revenue 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 the Company s 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 $10 million for the year ended December 31, 2008, compared to 2007, due to:

General and administrative 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.

West Region

2009 compared to 2008

The following table provides selected financial information for the West region for the years ended December 31, 2009, and 2008:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Change %
	(In millions except otherwise noted)		
Operating Revenues			
Energy revenue	$ 34	$ 39	(13)%
Capacity revenue	122	125	(2)
Risk management activities	(8)		
Other revenues	2	7	(71)
Total operating revenues	150	171	(12)
Operating Costs and Expenses			
Cost of energy	29	35	(17)
Depreciation and amortization	8	8	
Other operating expenses	81	70	16
Operating Income	$ 32	$ 58	(45)
MWh sold (in thousands)	1,279	1,532	(17)
MWh generated (in thousands)	1,279	1,532	(17)
Business Metrics			
Average on-peak market power prices ($/MWh)	$ 40.10	$ 82.20	(51)
Cooling Degree Days, or CDDs[(a)]	908	953	(5)
CDD s 30-year rolling average	704	704	
Heating Degree Days, or HDDs[(a)]	3,105	3,190	(3)%
HDD s 30-year rolling average	3,228	3,243	

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

Operating Income

Operating income decreased by $26 million for the year ended December 31, 2009, compared to the same period in 2008, due to decreases in capacity revenue, energy revenue, risk management activities and other revenues.

Operating Revenues

Operating revenues decreased by $21 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Capacity revenue decreased by $3 million due to the expiration of a two-year tolling agreement at the El Segundo facility in April 2008, which was replaced by resource adequacy and capacity contracts at lower prices.

Energy revenue decreased by $5 million primarily due to a 16% decrease in merchant prices in 2009 compared to 2008. This decrease was offset by a 5% increase in merchant generation in 2009 compared to 2008.

Other revenues decreased by $5 million due to lower emission allowance sales partially offset by an increase in ancillary services revenue.

Risk management activities realized losses of $8 million on settled transactions were recognized during the period. There was no risk management activity in 2008. For further discussion of the Company s risk management activities, see Consolidated Results of Operations.

Cost of Energy and Other Operating Expenses

Cost of energy and other operating expenses increased by $5 million for the year ended December 31, 2009, compared to the same period in 2008, due to:

Cost of energy decreased by $6 million due to a 29% decline in average natural gas prices per MMBtu. This decrease was partially offset by an 8% increase in natural gas consumption and a $3 million increase in fuel oil expense resulting from a write-down to market of fuel oil inventory no longer used in the production of energy.

Other operating expenses increased by $11 million due to higher maintenance expense associated with a major overhaul at El Segundo and higher maintenance at Long Beach.

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, 2008		Year Ended December 31, 2007		Change%
	(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)	$	82.20	$	66.46	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

Operating income increased by $19 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

Operating Revenues

Operating revenues increased by $44 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

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

Capacity revenue 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:

- *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.

- *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.

Cost of Energy and Other Operating Expenses

Cost of energy and other operating expenses increased by $25 million for the year ended December 31, 2008, compared to the same period in 2007, due to:

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.

Other operating expenses 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.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2009, and 2008, NRG s liquidity, excluding collateral received, was approximately $3.8 billion and $3.4 billion, respectively, comprised of the following:

	As of December 31, 2009	As of December 31, 2008
	(In millions)	
Cash and cash equivalents	$ 2,304	$ 1,494
Funds deposited by counterparties	177	754
Restricted cash	2	16
Total cash	2,483	2,264
Synthetic Letter of Credit Facility availability	583	860
Revolving Credit Facility availability	905	1,000
Total liquidity	3,971	4,124
Less: Funds deposited as collateral by hedge counterparties	(177)	(760)
Total liquidity, excluding collateral received	$ 3,794	$ 3,364

For the year ended December 31, 2009, total liquidity, excluding collateral received, increased by $430 million due to a higher cash balance of $810 million, partially offset by decreased availability of the Synthetic Letter of Credit Facility and the Revolving Credit Facility of $277 million and $95 million, respectively. Changes in cash balances are further discussed hereinafter under *Cash Flow Discussion*. Cash and cash equivalents and funds deposited by counterparties at December 31, 2009, are predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

The line item Funds deposited by counterparties represents the amounts that are held by NRG as a result of collateral posting obligations from the Company s counterparties due to positions in the Company s hedging program. These amounts are segregated into separate accounts that are not contractually restricted but, based on the Company s intention, are not available for the payment of NRG s general corporate obligations. 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. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company s balance sheet, with an offsetting liability for this cash collateral received within current liabilities. The decrease in these amounts from December 31, 2008, was due to cash collateral moved from NRG to Merrill Lynch in connection with novations under the CSRA (see Item 14 Note 3, *Business Acquisitions*, to the Consolidated Financial Statements), offset by a increase of in-the-money positions as a result of decreasing forward prices.

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.

The following table summarizes the credit ratings for NRG Energy, Inc., its Term Loan Facility and its Senior Notes as of December 31, 2009:

	S&P	**Moody s**	**Fitch**
NRG Energy, Inc.	BB−	Ba3	B
8.5% Senior Notes due 2019	BB−	B1	B+
7.375% Senior Notes, due 2016, 2017	BB−	B1	B+
7.25% Senior Notes due 2014	BB−	B1	B+
Term Loan Facility	BB+	Baa3	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, 2009, 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, 2009, NRG had issued $717 million of letters of credit under the Synthetic Letter of Credit Facility, leaving $583 million available for future issuances. Under the Revolving Credit Facility as of December 31, 2009, NRG had issued letters of credit of $95 million, of which $59 million supports the tax exempt bonds issued by Dunkirk Power LLC as described in Item 14 Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements.

2019 Senior Notes

On June 5, 2009, NRG completed the issuance of $700 million aggregate principal amount of 8.5% Senior Notes due 2019, or 2019 Senior Notes, as described in Item 14 Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements. The Company used a portion of the net proceeds of $678 million to facilitate the early termination on October 5, 2009 of NRG s obligations pursuant to the CSRA Amendment. Net proceeds in excess of this amount are available for general corporate purposes. See further discussion of the CSRA Amendment in Item 14 Note 3, *Business Acquisitions,* to the Consolidated Financial Statements.

Merrill Lynch Credit Sleeve Facility

See discussion in Item 14 Note 3, *Business Acquisitions,* to the Consolidated Financial Statements, regarding the CSRA entered into to support the retail business as a result of the acquisition of Reliant Energy on May 1, 2009. Effective October 5, 2009, the Company executed the CSRA Amendment. In connection with this amendment, the Company posted $366 million of cash collateral to Merrill Lynch and other counterparties, returned $53 million of counterparty collateral, issued $206 million of letters of credit, and received $45 million of counterparty collateral. In addition, Merrill Lynch returned $250 million of previously posted cash collateral, and released liens on $322 million of unrestricted cash held by Reliant Energy. Upon execution of the CSRA Amendment, the Company was required to post collateral for any net liability derivatives, and other static margin associated with supply for Reliant Energy.

TANE Facility

On February 24, 2009, NINA executed an EPC agreement with TANE, which specifies the terms under which STP Units 3 and 4 will be constructed. Concurrent with the execution of the EPC agreement, NINA and TANE entered into the TANE Facility wherein TANE has committed up to $500 million to finance purchases of long-lead materials and equipment for the construction of STP Units 3 and 4. The TANE Facility matures on February 24, 2012, subject to two renewal periods, and provides for customary events of default, which include, among others: nonpayment of principal or interest; default under other indebtedness; the rendering of judgments; and certain events of bankruptcy or insolvency. Outstanding borrowings will accrue interest at LIBOR plus 3%, subject to a ratings grid, and are secured by substantially all of the assets of and membership interests in NINA and its subsidiaries. As of December 31, 2009, no amounts had been borrowed under the TANE Facility.

Dunkirk Power LLC Tax-Exempt Bonds

On April 15, 2009, NRG executed a $59 million tax-exempt bond financing through its wholly-owned subsidiary, Dunkirk Power LLC. The bonds were issued by the County of Chautauqua Industrial Development Agency and will be used for construction of emission control equipment on the Dunkirk Generating Station in Dunkirk, NY. The bonds initially bear weekly interest based on the Securities Industry and Financial Markets Association, or SIFMA, rate, have a maturity date of April 1, 2042, and are enhanced by a letter of credit under the Company s Revolving Credit Facility covering amounts drawn on the facility. The proceeds received through December 31, 2009, were $52 million with the remaining balance being released over time as construction costs are paid. On February 1, 2010, the Company fixed the rate on the bonds at 5.875%. Interest will be payable semiannually. In addition, the $59 million letter of credit issued by NRG in support of the bonds was cancelled and replaced with a parent guarantee. These bonds are part of the Company s first lien debt.

GenConn Energy LLC related financings

In April 2009, NRG Connecticut Peaking LLC., a wholly-owned subsidiary of NRG, executed an equity bridge loan facility, or EBL, in the amount of $121.5 million from a syndicate of banks. The purpose of the EBL is to fund the Company s proportionate share of the project construction costs required to be contributed into GenConn Energy LLC, or GenConn, a 50% equity method investment of the Company. The EBL, which is fully collateralized with a letter of credit issued under the Company s Synthetic Letter of Credit Facility covering amounts drawn on the facility, will bear interest at a rate of LIBOR plus 2% on drawn amounts. The EBL will mature on the earlier of the commercial operations date of the Middletown project or July 26, 2011. The EBL also requires mandatory prepayment of the portion of the loan utilized to pay costs of the Devon project, of approximately $54 million, on the earlier of Devon s commercial operations date or January 27, 2011. The proceeds of the EBL received through December 31, 2009, were $108 million and the remaining amounts will be drawn as necessary to fund construction costs.

In April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a 7-year term loan facility, and also entered into a 5-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the revolving facility. In August 2009, GenConn began to draw under the GenConn Facility to cover costs related to the Devon project and as of December 31, 2009, has drawn $48 million.

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.

NRG s lien counterparties may have a claim on the Company s assets to the extent market prices exceed the hedged price. As of December 31, 2009 and February 9, 2010, all hedges under the first and second lien were in-the-money on a counterparty aggregate basis.

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 9, 2010:

Equivalent Net Sales Secured by First and Second Lien Structure[a]	**2010**	**2011**	**2012**	**2013**
In MW[b]	3,358	2,931	1,520	732
As a percentage of total forecasted baseload capacity[c]	49%	43%	22%	11%

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.
(b) 2010 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.

Asset Sales

MIBRAG On June 10, 2009, NRG completed the sale of its 50% ownership interest in Mibrag B.V. to a consortium of Severoćeské doly Chomutov, a member of the CEZ Group, and J&T Group. Mibrag B.V. s principal holding was MIBRAG, which was jointly owned by NRG and URS Corporation. As part of the transaction, URS Corporation also entered into an agreement to sell its 50% stake in MIBRAG.

For its share, NRG received EUR 203 million ($284 million at an exchange rate of 1.40 U.S.$/EUR), net of transaction costs. During the year ended December 31, 2009, NRG recognized a pre-tax gain of $128 million. Prior to completion of the sale, NRG continued to record its share of MIBRAG s operations to Equity in earnings of unconsolidated affiliates.

In connection with the transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. The foreign currency forward contract had a fixed exchange rate of 1.277 and required NRG to deliver EUR 200 million in exchange for $255 million on June 15, 2009. For the year ended December 31, 2009, NRG recorded an exchange loss of $24 million on the contract within Other income/(loss), net.

ITISA On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V., or 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 Item 14 Note 4, *Discontinued Operations and Dispositions*, to the Consolidated Financial Statements, 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, 2009, commercial operations had total cash collateral outstanding of $359 million, and $508 million outstanding in letters of credit to third parties primarily to support its economic hedging activities for both wholesale and retail transactions. As of December 31, 2009, total collateral held from counterparties was $177 million, and $24 million of letters of credit.

Upon execution of the CSRA Amendment, effective October 5, 2009, the Company was required to post collateral for any net liability derivatives, and other static margin associated with supply for Reliant Energy that was transferred to NRG. As of January 29, 2010, all wholesale energy supply contracts relating to retail supply hedging were transferred to the Company, so that Merrill Lynch was no longer providing any credit support for wholesale energy supply contracts relating to retail supply hedging.

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. The 2010 mandatory offer related to 2009 is expected to be $430 million, against which the Company made a prepayment of $200 million in December 2009. Based on current credit market conditions, the Company expects that its lenders will accept in full the 2010 mandatory offer related to 2009, and, as such, the Company has reclassified approximately $230 million of Term Loan Facility maturity from a non-current to a current liability as of December 31, 2009.

On October 9, 2009, NRG commenced the process of unwinding the CSF II Debt, making a $181 million capital contribution to a CSF II cash account, effectively restricting the cash for the benefit of Credit Suisse Group, or CS. On October 13, 2009, CS began the process of unwinding their hedges in connection with the CSF II structure, which they completed by November 24, 2009. Once complete, CS returned 5,400,000 shares of NRG common stock borrowed under the Share Lending Agreements, and released 9,528,930 common shares held as collateral for the CSF II Debt, and the Company remitted payment to CS of the $181 million for outstanding principal and interest. The CSF II Debt contained an embedded derivative feature, or CFS II CAGR, which required NRG to pay CS at maturity, either in cash or stock at NRG s option, the excess of NRG s then current stock price over a Threshold Price of $40.80 per share. On November 24, 2009, the CSF II CAGR expired with no payment due.

Principal payments on debt and capital leases as of December 31, 2009, are due in the following periods:

Subsidiary/Description	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Debt:							
8.5% Notes due 2019	$	$	$	$	$	$ 700	$ 700
7.375% Notes due 2017						1,100	1,100
7.375% Notes due 2016						2,400	2,400
7.25% Notes due 2014					1,200		1,200
Term Loan Facility, due 2013	261	32	32	1,888			2,213
CSF I notes and preferred interests, due June 2010	190						190
NRG Energy Center Minneapolis LLC, due 2013 and 2017	11	12	13	10	6	21	73
Dunkirk Power LLC tax-exempt bonds, due April 2042						52	52
NRG Connecticut Peaking LLC, equity bridge loan facility	54	54					108
Nuclear Innovation North America LLC, due 2010	20						20
NRG Repowering Holdings LLC, due 2011		19					19
NRG Peaker Finance Co. LLC, due June 2019	20	21	22	23	29	136	251
Subtotal Debt, Bonds and Notes	556	138	67	1,921	1,235	4,409	8,326
Capital Lease:							
Saale Energie GmbH, Schkopau	22	10	8	8	7	68	123
Total Payments and Capital Leases	$ 578	$ 148	$ 75	$ 1,929	$ 1,242	$ 4,477	$ 8,449

In addition to the debt and capital leases shown in the preceding table, NRG had issued $717 million of letters of credit under the Company s $1.3 billion Synthetic Letter of Credit Facility and $95 million of letters of credit under the Company s Revolving Credit Facility as of December 31, 2009. The Company s Revolving Credit Facility matures on February 2, 2011, and the Synthetic Letter of Credit Facility matures on February 1, 2013.

Capital Expenditures

For the year ended December 31, 2009, the Company s capital expenditures, including accruals, were approximately $783 million. The following table summarizes the Company s capital expenditures for the year ended December 31, 2009 and the estimated capital expenditure and repowering investments forecast for 2010.

	Maintenance	Environmental	Repowering	Total
		(In millions)		
Northeast	$ 30	$ 172	$ 5	$ 207
Texas	160		29	189
South Central	9			9
West	4		4	8
Reliant Energy	7			7
Wind			120	120
Nuclear Development			197	197
Other	46			46
Total	$ 256	$ 172	$ 355	$ 783
Estimated capital expenditures for 2010	$ 241	$ 233	$ 707	$ 1,181

*Repowering*NRG *capital expenditures and investments* *Repowering*NRG project capital expenditures consisted of approximately $197 million related to the development of STP Units 3 and 4 in Texas, $120 million related to the Company s Langford wind farm project which became commercially operational in December 2009 and $29 million for the construction of Cedar Bayou Unit 4 in Texas.

The Company s repowering capital expenditures for 2010 are expected to be approximately $707 million. Of this amount, $684 million is estimated for STP Units 3 and 4 without giving effect to any partner contributions or potential equity sell down.

Major maintenance and environmental capital expenditures The Company s maintenance capital expenditures were $256 million, of which $160 million was related to the Texas region s assets including approximately $61 million in nuclear fuel expenditures related to STP Units 1 and 2. The Company s environmental capital expenditures were $172 million consisting of $130 million at the Huntley and Dunkirk plants due to the baghouse projects and $31 million at the Indian River plant due to a project to install selective catalytic reduction systems, scrubbers and fabric filters on Units 3 and 4. On February 3, 2010, NRG and DNREC announced a proposed plan, subject to definitive documentation, that would shut down Unit 3 by December 31, 2013 and relieve NRG of the requirement to install this back end control equipment on this unit. Unit 4 is not affected by this plan and construction on similar equipment continues with an expected in service date of year end 2011.

NRG anticipates funding these maintenance capital projects primarily with funds generated from operating activities. In addition, on April 15, 2009, the Company executed a $59 million tax-exempt bond financing through its wholly-owned subsidiary, Dunkirk Power LLC, with the bonds issued by the County of Chautauqua Industrial Development Agency. These funds are expected to fund environmental capital expenditures at the Dunkirk facility.

Loans to affiliates The Company had funded approximately $48 million in interest bearing loans to GenConn Energy LLC, a 50/50 joint venture vehicle of NRG and the United Illuminating Company as part of the Devon and Middletown plant repowering projects prior to the closing of the EBL and GenConn Facility. During 2009, these loans were repaid with proceeds from the EBL financing. Subsequent to the financing, the equity portion of construction costs for GenConn is funded through the EBLs of NRG Connecticut Peaking and United Illuminating. These funds are made available to GenConn through convertible interest bearing promissory notes that convert to equity upon repayment of the EBL loans by NRG Connecticut Peaking and United Illuminating. As of December 31, 2009, there was $108 million outstanding under the loan from NRG Connecticut Peaking.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2010 through 2014 to meet NRG s environmental commitments will be approximately $0.9 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 U.S. EPA.

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

	Texas	Northeast	South Central	Total
		(In millions)		
2010	$	$ 230	$ 3	$ 233
2011		179	52	231
2012	6	45	108	159
2013	39	9	109	157
2014	50	4	$ 68	122
Total	$ 95	$ 467	$ 340	$ 902

This estimate reflects the recent announcement to retrofit only Unit 4 at the Indian River Generating Station and shifts in the timing of other projects to reflect anticipated issuance dates for revised regulations.

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 regions 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.

Capital Allocation

2009 Capital Allocation Plan In addition to the aforementioned planned investments in maintenance and environmental capital expenditures and *Repowering*NRG in 2009, and the 2009 repayment of Term Loan Facility debt to the first lien lenders, the Company s Capital Allocation Plan included the completion of the 2008 Capital Allocation Plan with the purchase of $30 million of common stock as well as the purchase of an additional $300 million in common stock under the previously announced 2009 Capital Allocation Plan. In July 2009, as part of the Company s 2009 Capital Allocation Program, the Board of Directors approved an increase to the Company s previously authorized common share repurchases under its capital allocation plan from the existing $330 million to $500 million. The Company s repurchases during the year ended December 31, 2009, were $500 million.

2010 Capital Allocation Plan On February 23, 2010, the Company announced its 2010 Capital Allocation Plan to purchase $180 million in common stock. The Company s share repurchases are subject to market prices, financial restrictions under the Company s debt facilities, and as permitted by securities laws. As part of the 2010 plan, the

Company will invest approximately $474 million in maintenance and environmental capital expenditures in existing assets and $707 million 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 2010 the Company will offer its first lien lenders $430 million of its 2009 excess cash flow (as defined in the Senior Credit Facility) of which the Company made a prepayment of $200 million in December 2009.

Preferred Stock Dividend Payments

For the year ended December 31, 2009, NRG paid $6 million, $17 million and $10 million in dividend payments to holders of the Company s 5.75%, 4% and 3.625% Preferred Stock. On March 16, 2009, the outstanding shares of the 5.75% Preferred Stock converted into common stock and, as a result, there will be no further dividends paid with respect to this series of preferred stock. During 2009, a total of 265,870 shares of the 4% Preferred Stock were converted into common stock and 73 shares were redeemed for cash.

Benefit Plans Obligations

As of December 31, 2009, NRG contributed $27 million towards its three defined benefit pension plans to meet the Company s 2009 benefit obligation. Based on the Company s December 31, 2009 measurement of its benefit obligation for its three defined benefit pension plans, the Company is expected to contribute another $18 million to these plans during 2010, $5 million of which also relates to the Company s 2009 benefit obligation.

Reliant Energy Customer Deposits

Revisions in the PUCT rules will require that NRG keep a segregated account, or that the Company post a fully collateralized letter of credit on or before May 21, 2010 to cover outstanding customer deposits and residential advance payments. The Company s current plan is to file for an amendment to its Retail Energy Provider recertification applications during the first quarter 2010 and post a letter of credit to satisfy the rule changes. The amount of deposits subject to segregation or collateralization at December 31, 2009, was $54 million.

Cash Flow Discussion

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,		
	2009	2008	Change
	(In millions)		
Net cash provided by operating activities	$ 2,106	$ 1,479	$ 627
Net cash used by investing activities	(954)	(672)	(282)
Net cash used by financing activities	(343)	(487)	144

Net Cash Provided By Operating Activities

For the year ended December 31, 2009, net cash provided by operating activities increased by $627 million compared to the same period in 2008, due to:

Cash generated by Reliant Energy Reliant Energy contributed approximately $855 million to the Company s consolidated cash flow from operations in 2009, primarily reflecting $966 million in pre-tax income since the May 1, 2009, acquisition date, adjusted for the non-cash effects of depreciation and amortization and changes in derivatives.

Lower cash flows from Wholesale Power Generation The Company s cash flow from operation excluding Reliant Energy was lower by approximately $228 million in 2009 compared to 2008, as decreases in generation and power prices impacted results from operations. In addition, $16 million more cash was used for working capital in 2009 compared to 2008, as higher coal inventory balances were partially offset by $72 million in lower pension contributions.

Net Cash Used By Investing Activities

For the year ended December 31, 2009, net cash used in investing activities increased by $282 million compared to the same period in 2008, due to:

Acquisition of businesses During 2009, the Company paid $427 million, net of cash acquired of $6 million, to acquire three businesses.

Proceeds from sale of equity method investment and discontinued operations Net proceeds from investing activities increased by $43 million in 2009 as compared to 2008 due to the sale of MIBRAG in June 2009 for net proceeds of $284 million compared to the sale of ITISA for proceeds, net of divested cash, of $241 million in April 2008.

Capital expenditures and loans to affiliates NRG s capital expenditures decreased by $165 million due to decreased spending on *Repowering*NRG.

Trading of emission allowances Net purchases and sales of emission allowances resulted in a decrease in cash of $105 million for 2009 as compared to 2008.

Net Cash Used By Financing Activities

For the year ended December 31, 2009, net cash used by financing activities decreased by $144 million compared to the same period in 2008, due to:

Issuance of debt During 2009, the Company received $688 million in gross proceeds from the 2019 Senior Notes, $108 million in NRG Connecticut Peaking financing, $52 million from the Dunkirk bonds and $19 million from other borrowings. During 2008, the Company received $20 million in proceeds from borrowings which resulted in a net cash increase of $872 million.

Term Loan Facility debt payment In 2009, the Company paid down $429 million of its Term Loan Facility, including the payment of excess cash flow, as discussed above under *Debt Service Obligations*. The Company paid down $174 million of its Term Loan Facility during 2008 which resulted in a net cash decrease of $255 million.

Other debt payments In November 2009, the Company paid $181 million to CS for the benefit of CSF II to unwind the Company s CSF II notes and preferred interests.

Share repurchase During 2009, the Company repurchased common stock of $500 million as compared to $185 million in 2008, which resulted in a net cash decrease of $315 million.

NOLs, Deferred Tax Assets and Uncertain Tax Position Implications, under ASC-740, Income Taxes, or ASC 740

As of December 31, 2009, the Company had generated total domestic pre-tax book income of $1.5 billion and foreign continuing pre-tax book income of $161 million. The Company has net operating losses for tax return purposes available to offset taxable income in the current period. The tax return net operating losses have been classified as capital loss carryforwards for financial statement purposes and a full valuation allowance has been established. As of December 31, 2009, these capital losses have expired for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $280 million, of which $82 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 $643 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 $75 million in 2010.

However, as the position remains uncertain for the $643 million of tax effected unrecognized tax benefits, the Company has recorded a non-current tax liability of $347 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $347 million non-current tax liability for unrecognized tax benefits is primarily due to taxable earnings for the period for which there are no NOLs available to offset for financial statement purposes.

The Company is under examination by the Internal Revenue Service for years 2004 through 2006. It is possible that the IRS examination may conclude during 2010 but because of a possible extension, an estimate of the range of reasonably possible changes in unrecognized tax benefits cannot be made.

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 14 Note 26, *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.

Derivative Instrument Obligations

The Company s 3.625% Preferred Stock includes a feature which is considered an embedded derivative per ASC 815. Although it is considered an embedded derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to ASC 815. As of December 31, 2009, based on the Company s stock price, the embedded derivative was out-of-the-money and had no redemption value. See also Item 14 Note 15, *Capital Structure,* 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, 2009, 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 $93 million as of December 31, 2009. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 14 Note 16, *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 14 Note 12, *Debt and Capital Leases*, Note 22, *Commitments and Contingencies*, and Note 26, *Guarantees* , to the Consolidated Financial Statements for additional discussion.

	By Remaining Maturity at December 31, 2009					
Contractual Cash Obligations	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total[b]**	**2008 Total**
	(In millions)					
Long-term debt (including estimated interest)	$ 1,074	$ 1,195	$ 3,950	$ 5,171	$ 11,390	$ 11,142
Capital lease obligations (including estimated interest)	28	30	27	107	192	321
Operating leases	100	120	98	264	582	421
Fuel purchase and transportation obligations[a]	1,011	405	140	600	2,156	2,378
Purchased power commitments[c]	55	56	10		121	
Pension minimum funding requirement[d]	21	55	56	31	163	194
Other postretirement benefits minimum funding requirement[e]	4	6	8	5	23	19
Other liabilities[f]	53	75	38	230	396	98
Total	$ 2,346	$ 1,942	$ 4,327	$ 6,408	$ 15,023	$ 14,573

(a) Includes only those coal transportation and lignite commitments for 2010 as no other nominations were made as of December 31, 2009. Natural gas nomination is through February 2011.
(b) Excludes $347 million non-current payable relating to NRG s uncertain tax benefits under ASC-740 as the period of payment cannot be reasonably estimated. Also excludes $415 million of asset retirement obligations which are discussed in Item 14 Note 13, *Asset Retirement Obligations,* to the Consolidated Financial Statements.
(c) Includes commitments with both fixed and variable components.
(d) 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 2015 is currently not available.
(e) These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2015 are currently not available.
(f) Includes water right agreements, service and maintenance agreements, stadium naming rights and other contractual obligations.

	By Remaining Maturity at December 31, 2009					
	Under			**Over**		**2008**

uarantees, Indemnifications and Other Contingent Obligations	1 Year	1-3 Years	3-5 Years	5 Years	Total	Total
			(In millions)			
ynthetic letters of credit	$ 531	$ 186	$	$	$ 717	$ 440
nfunded standby letters of credit and surety bonds	61	36			97	5
sset sales guarantee obligations		118		8	126	129
ommercial sales arrangements	104	44	103	965	1,216	1,005
ther guarantees				117	117	80
otal	$ 696	$ 384	$ 103	$ 1,090	$ 2,273	$ 1,659

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 and to hedge fuel requirements at generation facilities. 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 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.

The tables below disclose the activities that include both exchange and non-exchange traded contracts accounted for at fair value in accordance with ASC 820, *Fair Value Measurements and Disclosures*, or ASC 820. Specifically, these tables disaggregate realized and unrealized changes in fair value; disaggregate estimated fair values at December 31, 2009, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2009. Also, in connection with the Company s acquisition of Reliant Energy, NRG acquired retail load and supply contracts. The tables below also includes the fair value of these contracts receiving mark-to-market accounting treatment as of May 1, 2009.

Derivative Activity Gains/(Losses)	**(In millions)**
Fair value of contracts as of December 31, 2008	$ 996
Contracts realized or otherwise settled during the period	(432)
Contracts acquired in conjunction with Reliant Energy	(1,054)
Changes in fair value	949
Fair value of contracts as of December 31, 2009	$ 459

	Fair Value of Contracts as of December 31, 2009				
Fair value hierarchy 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)		
Level 1	$ 25	$ (13)	$ (24)	$	$ (12)
Level 2	159	234	118	(27)	484
Level 3	(21)	7	1		(13)
Total	$ 163	$ 228	$ 95	$ (27)	$ 459

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. A significant portion of the fair value of the Company s derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate the Company s transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. 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 3% 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 after cash collateral paid/received under a specific master agreement is an asset, the Company calculates credit reserve applying the counterparty s default swap rate. If the net exposure after cash collateral paid/received under a specific master agreement is a liability, the Company calculates credit reserve applying 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, 2009, the credit reserve resulted in a $1 million increase in fair value which is composed of a $1 million loss in OCI and a $2 million gain in derivative revenue and cost of operations.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2009 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.

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company s derivative assets or liabilities are recorded on a separate line item on the balance sheet. 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 6A *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 NRG s hedging activity. As of December 31, 2009, NRG s net derivative asset was $459 million, a decrease to total fair value of $537 million as compared to December 31, 2008. This decrease was primarily driven by the acquisition of Reliant Energy s retail portfolio offset by increase in fair value due to the decreases in gas and power prices as well as the roll-off of trades that settled during the period.

Based on a sensitivity analysis using simplified assumptions, the impact of a $1 per MMBtu increase or decrease in natural gas prices across the term of the derivative contracts would cause a change of approximately $489 million in the net value of derivatives as of December 31, 2009.

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 U.S. 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 14 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

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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 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 to withstand legal challenges of tax authority decisions or appeals Anticipated future decisions of tax authorities Application of tax statutes and regulations to transactions Ability to utilize tax benefits through carry backs to prior periods and carry forwards 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 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 intangible assets acquired in business combinations
Contingencies	Estimated financial impact of event(s) Judgment about likelihood of event(s) occurring Regulatory and political environments and requirements
Accrued Unbilled Revenues of Reliant Energy	Estimates of unbilled volumes

Derivative Instruments

The Company follows the guidance of ASC 815, to account for derivative instruments. ASC 815 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 the Company s earnings. These estimations are considered to be critical accounting estimates.

Certain derivative instruments that meet the criteria for derivative accounting treatment also qualify for a scope exception to derivative accounting, as they are considered 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, 2009, NRG had a valuation allowance of $233 million. This amount is comprised of U.S. domestic capital loss carryforwards and non-depreciable property of $154 million, foreign net operating loss carryforwards of $78 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.

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 ASC-360, *Property, Plant, and Equipment*, or ASC 360, 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 ASC 360, 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. There were no impairment charges on this investment in 2009.

NRG is also required to evaluate its equity-method and cost-method investments to determine whether or not they are impaired. ASC-323, *Investments-Equity Method and Joint Ventures*, or ASC 323, provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under ASC 323 is whether the value is considered an other than a temporary decline in value. The evaluation and measurement of impairments under ASC 323 involves the same uncertainties as described for long-lived assets that the Company owns directly and accounts for in accordance with ASC 360. 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 ASC 360, NRG would record its proportionate share of that impairment loss and would evaluate its investment for an other than temporary decline in value under ASC 323.

Goodwill and Other Intangible Assets

As part of the acquisition of Texas Genco in 2006, NRG recorded goodwill and intangible assets at its Texas segment reporting unit. The Company also recorded intangible assets in connection with the Reliant Energy acquisition in 2009, measured primarily based on significant inputs that are not observable in the market and thus represent a Level 3 measurement as defined in ASC 820. See Item 14 Note 3, *Business Acquisitions*, to the Consolidated Financial Statements for a discussion of the Reliant Energy acquisition fair value measurements. The Company applied ASC 805, *Business Combinations,* or ASC 805, and ASC 350, *Intangibles Goodwill and Other*, or ASC 350, to account for its goodwill and intangible assets. 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. The Company tests goodwill for impairment at the reporting unit level, which is identified by assessing whether the components of the Company s operating segments constitute businesses for which discrete financial information is available and whether 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, 2009, for its Texas reporting unit, or NRG Texas, which is at the operating segment level. The Company determined the fair value of this reporting unit using primarily an income approach and then applied an overall market approach reasonableness test to reconcile that fair value with NRG s overall market capitalization. Significant inputs to the determination of fair value were as follows:

For the three solid-fuel baseload plants that drive a majority of the value in the reporting unit, and for the region s Elbow Creek, Langford and Cedar Bayou facilities that recently commenced operations, the Company applied a discounted cash flow methodology to their long-term budgets in accordance with the guidance in paragraphs B152 and B155 of SFAS 142. This approach is consistent with that used to determine fair value at December 31, 2008 and 2007. These budgets are based on the Company s views of power and fuel prices, which consider market prices in the near term and the Company s fundamental view for the longer term as some relevant market prices are illiquid beyond 24 months. Hedging is included to the extent of contracts already in place. Projected generation in the long-term budgets is based on management s estimate of supply and demand within the sub-markets for each plant and the physical and economic characteristics of each plant;

For the reporting unit s remaining gas plants, the Company applied a market-derived earnings multiple to the gas plants aggregate estimated 2009 earnings before interest, taxes, depreciation and amortization, in accordance with the guidance in ASC-350-20-35-24. This approach is consistent with that used to determine fair values at December 31, 2008 and 2007;

The potential impact of carbon legislation was estimated using a discounted cash flow methodology applied to the Company s view of the impact of potential legislation that is based on recent proposals to Congress.

If fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, the Company estimated the fair value of NRG Texas invested capital to exceed its carrying value by approximately 25% at December 31, 2009. This estimate of fair value is affected by assumptions about projected power prices, generation, fuel costs, capital expenditure requirements and environmental regulations, and the Company believes that the most significant impact arises from future power prices. Assuming all other factors are held constant, a hypothetical $1 drop in the Company s long-term natural gas price view would not have caused the fair value of NRG Texas to fall below its carrying value at December 31, 2009.

To reconcile the fair value determined under the income approach with NRG s market capitalization, the Company considered historical and future budgeted earnings measures to estimate the average percentage of total company value represented by NRG Texas, and applied this percentage to an adjusted business enterprise value of NRG. To derive this adjusted business enterprise value, the Company applied a range of control premiums based on recent market transactions to the business enterprise value of NRG on a non-controlling, marketable basis, and also made adjustments for some non-operating assets and for some of the significant factors that impact NRG differently from NRG Texas, such as environmental capital expenditures outside of the Texas region, or limitations on the Company s Capital Allocation Plans under NRG s debt. The Company was able to reconcile the proportional value of NRG Texas to NRG s market capitalization at a value that would not indicate an impairment.

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 14 Note 22, *Commitments and Contingencies,* to the Consolidated Financial Statements.

Accrued Unbilled Revenues

Accrued unbilled revenues related to the Reliant Energy segment are critical accounting estimates as volumes are not precisely known at the end of each reporting period and the revenue amounts are material. Accrued unbilled revenues were $308 million as of December 31, 2009, which represents 3% of the Company s consolidated revenues for the year ended December 31, 2009, and 7% of Reliant Energy s revenues for the eight-month period ended December 31, 2009. Accrued unbilled revenues are based on Reliant Energy s estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

Recent Accounting Developments

See Item 14 Note 2, *Summary of Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of recent accounting developments.

Item 6A ***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.

NRG s portfolio consists of generation assets and full requirement load serving obligations. NRG manages the commodity price risk of the Company s merchant generation operations and load serving obligations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases and 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 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 those derivative contracts.

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 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 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, 2009, 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 $38 million.

The following table summarizes average, maximum and minimum VaR for NRG for the year ended December 31, 2009, and 2008:

VaR	**In millions**
As of December 31, 2009	$ 38
Average	41
Maximum	55
Minimum	28
As of December 31, 2008	$ 43
Average	50
Maximum	65
Minimum	35

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, 2009, for the entire term of these instruments entered into for both asset management and trading, was $24 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 May 2009, NRG entered into a series of forward-starting interest rate swaps. These interest rate swaps become effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company will pay its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the monthly equivalent of a floating interest payment based on a 1-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made monthly and the LIBOR is determined in advance of each interest period. The total notional amount of these swaps, which mature on February 1, 2013, is $900 million.

In 2006, the Company entered into a series of interest rate swaps which 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, 2009, was $1.7 billion. 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, 2010	$ 190 million
March 31, 2011	$ 1.55 billion

In addition to those discussed above, the Company had the following additional interest rate swaps outstanding as of December 31, 2009:

	Notional Value	**Maturity**
Floating to fixed interest rate swap for NRG Peaker Financing LLC	$ 251 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, 2009, the Company would have owed the counterparties $104 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, 2009, a 1% change in interest rates would result in a $10 million change in interest expense on a rolling twelve month basis.

As of December 31, 2009, the Company s long-term debt fair value was $8.2 billion and the carrying amount was $8.3 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 $415 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 for power and gas positions under marginable contracts, a $1 per MMBtu change in natural gas prices across the term of the marginable contracts would cause a change in margin collateral posted of approximately $128 million as of December 31, 2009, and a 0.25 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $51 million as of December 31, 2009. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2009. Currently, NRG is exposed to additional margin if natural gas prices decrease.

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, 2009, no letters of credit are outstanding to second lien counterparties. With changes in commodity prices, the letters of credit could grow to $64 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, prepayment arrangements, or volumetric limits; (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 nine 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.

As of December 31, 2009, total credit exposure to substantially all wholesale counterparties was $1.3 billion and NRG held collateral (cash and letters of credit) against those positions of $186 million resulting in a net exposure of $1.1 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 NPNS, 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)**
Financial institutions	69%
Utilities, energy merchants, marketers and other	25
Coal suppliers	3
ISOs	3
Total as of December 31, 2009	100%

Category	**Net Exposure[(a)] (% of Total)**
Investment grade	90%
Non-rated	8
Non- Investment grade	2
Total as of December 31, 2009	100%

(a) Credit exposure excludes California tolling, uranium, coal transportation/railcar leases, New England RMR, certain cooperative load contracts and Texas Westmoreland coal contracts. The aforementioned exposures were excluded for various reasons including regulatory support liens held against the contracts which serve to reduce the risk of loss, or credit risks for certain contracts are not readily measurable due to a lack of market reference prices.

NRG has credit risk exposure to certain wholesale counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $351 million. Approximately 82% of NRG s positions relating to credit risk roll-off by the end of 2012. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company s financial position or results of operations from nonperformance by any of NRG s counterparties.

NRG is exposed to retail credit risk through its competitive electricity supply business, which serves C&I customers and the Mass market in Texas. Retail credit risk results when a customer fails to pay for services rendered. The losses could be incurred from nonpayment of customer accounts receivable and any in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of December 31, 2009, the Company s credit exposure to C&I customers was diversified across many customers and various industries. No one customer represented more than 2% of total exposure and the majority of the customers have investment grade credit quality, as determined by NRG.

NRG is also exposed to credit risk relating to its 1.5 million Mass customers, which may result in a write-off of a bad debt. The current economic conditions may affect the Company s customers ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Certain of the Company s hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed adequate assurance under the agreements. Other agreements contain provisions that require the Company to post additional collateral if there was a one notch downgrade in the Company s credit rating. The collateral required for out-of-the-money positions and net accounts payable for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2009, was $80 million. The collateral required for out-of-the-money positions and net accounts payable for contracts with credit rating contingent features that are in a net liability position as of December 31, 2009, was $49 million. The Company is also a party to certain marginable agreements where NRG has a net liability position but the counterparty has not called for the collateral due, which is approximately $3 million as of December 31, 2009.

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, 2009, no foreign currency options and forward contracts were outstanding.

In connection with the MIBRAG sale transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. The foreign currency forward contract had a fixed exchange rate of 1.277 and required NRG to deliver EUR 200 million in exchange for $255 million on June 15, 2009. For the year ended December 31, 2009, NRG recorded an exchange loss of $24 million on the contract within Other income/(loss), net.

As a result of the Company s limited foreign currency exposure to date, the effect of foreign currency fluctuations has not been material to the Company s results of operations, financial position and cash flows.

The effects of a hypothetical simultaneous 10% appreciation in the U.S. dollar from year-end 2008 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 $79 million in pre-tax unrealized income reflected in the currency translation adjustment component of OCI.

Item 7 ***Financial Statements and Supplementary Data***

The financial statements and schedules are listed in Part IV, Item 14 of this Form 10-K.

Item 8 ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosures***

None.

Item 8A ***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 2009 Annual Report to Shareholders.

Changes in Internal Control over Financial Reporting

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 2009 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Inherent Limitations over Internal Controls

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

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

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

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

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

Item 8B ***Other Information***

None.

PART III

Item 9 ***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 2010 Annual Meeting of Stockholders.

Item 10 ***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 2010 Annual Meeting of Stockholders.

Item 11 ***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 2010 Annual Meeting of Stockholders.

Item 12 ***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 2010 Annual Meeting of Stockholders.

Item 13 ***Principal Accounting 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 2010 Annual Meeting of Stockholders.

PART IV

Item 14 *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 Statements of Operations Years ended December 31, 2009, 2008 and 2007

Consolidated Balance Sheets December 31, 2009 and 2008

Consolidated Statements of Cash Flows Years ended December 31, 2009, 2008 and 2007

Consolidated Statement of Stockholders Equity and Comprehensive Income/(Loss) Years ended December 31, 2009, 2008 and 2007

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 14(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.

(c) Not applicable

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, 2009.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2009 has been audited by KPMG LLP, the Company s independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited NRG Energy, Inc. s internal control over financial reporting as of December 31, 2009, 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, 2009, 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, 2009 and 2008, 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, 2009, and our report dated February 23, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
February 23, 2010

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, 2009 and 2008, 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, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, 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, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards (SFAS) 141R, *Business Combinations* (incorporated into Accounting Standards Codification (ASC) Topic 805, *Business Combinations*), SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, Consolidated Financial Statements* (incorporated into ASC Topic 810, *Consolidation*), Financial Accounting Standards Board Staff Position (FSP FAS) 141R-1, *Accounting for Assets and Liabilities Assumed in a Business Combination That Arise from Contingencies* (incorporated into ASC Topic 805, *Business Combinations*), and FSP Accounting Principles Board (APB) No. 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlements)* (incorporated into ASC Topic 825, *Financial Instruments*), effective January 1, 2009; SFAS No. 157, *Fair Value Measurements* (incorporated into ASC Topic 820, *Fair Value Measurements and Disclosures*), effective January 1, 2008; and FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of SFAS No. 109 (incorporated into ASC Topic 740, *Income Taxes*), effective January 1, 2007.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc. and subsidiaries internal control over financial reporting as of December 31, 2009, 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 23, 2010 expressed an unqualified opinion on the effective operation of internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
February 23, 2010

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
(In millions, except per share amounts)	**2009**	**2008**	**2007**
Operating Revenues			
Total operating revenues	$ 8,952	$ 6,885	$ 5,989
Operating Costs and Expenses			
Cost of operations	5,323	3,598	3,378
Depreciation and amortization	818	649	658
Selling, general and administrative	550	319	309
Acquisition-related transaction and integration costs	54		
Development costs	48	46	101
Total operating costs and expenses	6,793	4,612	4,446
Gain on sale of assets			17
Operating Income	2,159	2,273	1,560
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	41	59	54
Gains on sales of equity method investments	128		1
Other income/(loss), net	(5)	17	55
Refinancing expenses	(20)		(35)
Interest expense	(634)	(583)	(702)
Total other expenses	(490)	(507)	(627)
Income From Continuing Operations Before Income Taxes	1,669	1,766	933
Income tax expense	728	713	377
Income From Continuing Operations	941	1,053	556
Income from discontinued operations, net of income taxes		172	17
Net Income	941	1,225	573
Less: Net loss attributable to noncontrolling interest	(1)		
Net Income attributable to NRG Energy, Inc.	942	1,225	573
Dividends for preferred shares	33	55	55
Income Available for Common Stockholders	$ 909	$ 1,170	$ 518
Earnings per share attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding basic	246	235	240

Income from continuing operations per weighted average common share basic	$ 3.70	$ 4.25	$ 2.09
Income from discontinued operations per weighted average common share basic		0.73	0.07
Net Income per Weighted Average Common Share Basic	$ 3.70	$ 4.98	$ 2.16
Weighted average number of common shares outstanding diluted	271	275	288
Income from continuing operations per weighted average common share diluted	$ 3.44	$ 3.80	$ 1.90
Income from discontinued operations per weighted average common share diluted		0.63	0.06
Net Income per Weighted Average Common Share Diluted	$ 3.44	$ 4.43	$ 1.96
Amounts Attributable to NRG Energy, Inc.:			
Income from continuing operations, net of income taxes	942	1,053	556
Income from discontinued operations, net of income taxes		172	17
Net Income	$ 942	$ 1,225	$ 573

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2009	As of December 31, 2008
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,304	$ 1,494
Funds deposited by counterparties	177	754
Restricted cash	2	16
Accounts receivable trade, less allowance for doubtful accounts of $29 and $3	876	464
Current portion of note receivable affiliate and capital leases	32	68
Inventory	541	455
Derivative instruments valuation	1,636	4,600
Cash collateral paid in support of energy risk management activities	361	494
Prepayments and other current assets	279	147
Total current assets	6,208	8,492
Property, Plant and Equipment		
In service	14,083	13,084
Under construction	533	804
Total property, plant and equipment	14,616	13,888
Less accumulated depreciation	(3,052)	(2,343)
Net property, plant and equipment	11,564	11,545
Other Assets		
Equity investments in affiliates	409	490
Note receivable affiliate and capital leases, less current portion	504	435
Goodwill	1,718	1,718
Intangible assets, net of accumulated amortization of $648 and $335	1,777	815
Nuclear decommissioning trust fund	367	303
Derivative instruments valuation	683	885
Other non-current assets	148	125
Total other assets	5,606	4,771
Total Assets	$ 23,378	$ 24,808

See notes to Consolidated Financial Statements.

LIABILITIES AND STOCKHOLDERS EQUITY

	As of December 31, 2009		As of December 31, 2008	
	(In millions, except share data)			
LIABILITIES AND STOCKHOLDERS EQUITY				
Current Liabilities				
Current portion of long-term debt and capital leases	$	571	$	464
Accounts payable trade		693		447
Accounts payable affiliates		4		4
Derivative instruments valuation		1,473		3,981
Deferred income taxes		197		201
Cash collateral received in support of energy risk management activities		177		760
Accrued interest expense		207		178
Other accrued expenses		298		215
Other current liabilities		142		331
Total current liabilities		3,762		6,581
Other Liabilities				
Long-term debt and capital leases		7,847		7,697
Nuclear decommissioning reserve		300		284
Nuclear decommissioning trust liability		255		218
Postretirement and other benefit obligations		287		277
Deferred income taxes		1,783		1,190
Derivative instruments valuation		387		508
Out-of-market contracts		294		291
Other non-current liabilities		519		392
Total non-current liabilities		11,672		10,857
Total Liabilities		15,434		17,438
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; 154,057 shares issued and outstanding at December 31, 2009 (at liquidation value of $154, net of issuance costs) and 420,000 shares issued and outstanding at December 31, 2008 (at liquidation value of $420, net of issuance costs)		149		406
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 $460, net of issuance costs)				447
Common stock; $0.01 par value; 500,000,000 shares authorized; 295,861,759 and 263,599,200 shares issued and 253,995,308 and 234,356,717 shares outstanding at December 31, 2009 and 2008		3		3

Additional paid-in capital	4,948	4,350
Retained earnings	3,332	2,423
Less treasury stock, at cost - 41,866,451 and 29,242,483 shares at December 31, 2009 and 2008	(1,163)	(823)
Accumulated other comprehensive income	416	310
Noncontrolling interest	12	7
Total Stockholders Equity	7,697	7,123
Total Liabilities and Stockholders Equity	$ 23,378	$ 24,808

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Serial Preferred Stock	Preferred Shares	Common Stock	Common Shares	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Noncontrolling Interest	Total Stockholders Equity
						(In millions)				
Balances at December 31, 2006	$ 892	2.4	$ 3	245	$ 4,506	$ 735	$ (732)	$ 282	$	$ 5,686
Net income						573				573
Foreign currency translation adjustments								73		73
Unrealized loss on derivatives, net of $310 tax benefit								(474)		(474)
Available-for-sale securities, net of $1 tax								2		2
Defined benefit plan prior service cost of $4 and net loss of $2, net of $2 tax								2		2
Comprehensive income for 2007										176
Equity-based compensation				1	9					9
Reduction to tax valuation allowance					56					56
Preferred stock dividends						(55)				(55)
Purchase of treasury stock				(9)			(353)			(353)
Retirement of treasury stock					(447)		447			
Balances at December 31, 2007	892	2.4	3	237	4,124	1,253	(638)	(115)		5,519
Net income						1,225				1,225
Foreign currency translation adjustments, net of $22 tax								(112)		(112)
Reclassification adjustment for translation loss realized upon sale of ITISA								15		15
Unrealized gain on derivatives, net of $369 tax								580		580
Available-for-sale securities, net of $2 tax benefit								(4)		(4)
								(54)		(54)

Defined benefit plan prior service credit of $1 and net loss of $55, net of $35 tax benefit										
Comprehensive income for 2008										1,650
Equity-based compensation				1	25					25
Payment to settle CSF I CAGR					(45)					(45)
Purchase of treasury stock				(5)			(185)			(185)
Reduction to tax valuation allowance					162					162
Preferred stock dividends						(55)				(55)
NINA contribution, net of $17 tax					26				7	33
5.75% preferred stock conversion to common stock	(39)	(0.1)		1	39					
Other					19					19
Balances at December 31, 2008	$ 853	2.3	$ 3	234	$ 4,350	$ 2,423	$ (823)	$ 310	$ 7	$ 7,123
Net income/(loss)						942			(1)	941
Foreign currency translation adjustments, net of $21 tax								35		35
Reclassification adjustment for translation loss realized upon sale of MIBRAG, net of tax benefit $13								(22)		(22)
Unrealized gain on derivatives, net of $53 tax								91		91
Available-for-sale securities, net of $2 tax								4		4
Defined benefit plan prior service credit of $1 and net loss of $8, net of $1 tax benefit								(2)		(2)
Comprehensive income for 2009										1,047
Equity-based compensation					26					26
Purchase of treasury stock				(19)			(500)			(500)
Preferred stock dividends						(33)				(33)
ESPP share purchases					2					2
NINA contribution, net of $16 tax					28				6	34
5.75% preferred stock conversion to common stock	(447)	(1.9)		19	447					
	(257)	(0.3)		13	257					

4.00% preferred stock conversion to common stock										
Shares loaned to affiliate of CS				12	(291)		291			
Shares returned from affiliate of CS				(5)	131		(131)			
Other					(2)					(2)
Balances at December 31, 2009	$ 149	0.1	$ 3	254	$ 4,948	$ 3,332	$ (1,163)	$ 416	$ 12	$ 7,697

See notes to Consolidated Financial Statements

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
		(In millions)	
Cash Flows from Operating Activities			
Net income	$ 941	$ 1,225	$ 573
Adjustments to reconcile net income to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	(41)	(44)	(33)
Depreciation and amortization	818	649	661
Provision for bad debts	61		
Amortization of nuclear fuel	36	39	58
Amortization of financing costs and debt discount/premiums	44	37	79
Amortization of intangibles and out-of-market contracts	153	(270)	(156)
Amortization of unearned equity compensation	26	26	19
Loss/(gain) on disposals and sales of assets	17	25	(17)
Impairment charges and asset write downs		23	20
Changes in derivatives	(225)	(484)	77
Changes in deferred income taxes and liability for unrecognized tax benefits	689	762	359
Gain on sales of equity method investments	(128)		(1)
Gain on sale of discontinued operations		(273)	
Gain on sale of emission allowances	(4)	(51)	(31)
Gain recognized on settlement of pre-existing relationship	(31)		
Changes in nuclear decommissioning trust liability	26	34	32
Changes in collateral deposits supporting energy risk management activities	127	(417)	(125)
Cash provided/(used) by changes in other working capital, net of acquisition and disposition effects: Accounts receivable, net	88	1	(102)
Inventory	(83)	(5)	(38)
Prepayments and other current assets	26	(7)	22
Accounts payable	(176)	(31)	49
Option premiums collected	(282)	268	8
Accrued expenses and other current liabilities	48	(6)	98
Other assets and liabilities	(24)	(22)	(35)
Net Cash Provided by Operating Activities	2,106	1,479	1,517
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(427)		
Capital expenditures	(734)	(899)	(481)
Increase in restricted cash, net	14	13	12
(Increase)/decrease in notes receivable	(22)	10	34
Decrease in trust fund balances			19
Purchases of emission allowances	(78)	(8)	(161)
Proceeds from sale of emission allowances	40	75	272

Investments in nuclear decommissioning trust fund securities	(305)	(616)	(265)
Proceeds from sales of nuclear decommissioning trust fund securities	279	582	233
Proceeds from sale of assets, net	6	14	2
Proceeds from sale of equity method investment	284		
Equity investment in unconsolidated affiliate	(6)	(84)	
Purchases of securities			(49)
Proceeds from sale of discontinued operations and assets, net of cash divested		241	57
Other	(5)		
Net Cash Used by Investing Activities	(954)	(672)	(327)
Cash Flows from Financing Activities			
Payment of dividends to preferred stockholders	(33)	(55)	(55)
Net payments to settle acquired derivatives that include financing elements	(79)	(43)	
Payment for treasury stock	(500)	(185)	(353)
Installment proceeds from sale of noncontrolling interest in subsidiary	50	50	
Payment to settle CSF I CAGR		(45)	
Proceeds from issuance of common stock, net of issuance costs	2	9	7
Proceeds from issuance of long-term debt	892	20	1,411
Payment of deferred debt issuance costs	(31)	(4)	(5)
Payments for short and long-term debt	(644)	(234)	(1,819)
Net Cash Used by Financing Activities	(343)	(487)	(814)
Change in cash from discontinued operations		43	(25)
Effect of exchange rate changes on cash and cash equivalents	1	(1)	4
Net Increase in Cash and Cash Equivalents	810	362	355
Cash and Cash Equivalents at Beginning of Period	1,494	1,132	777
Cash and Cash Equivalents at End of Period	$ 2,304	$ 1,494	$ 1,132

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 primarily a wholesale power generation company with a significant presence in major competitive power markets in the U.S., as well a major retail electricity franchise in the ERCOT (Texas) market. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, the trading of energy, capacity and related products in the U.S. and select international markets, and supply of electricity and energy services to retail electricity customers in the Texas market.

As of December 31, 2009, NRG had a total global generation portfolio of 187 active operating fossil fuel and nuclear generation units, at 44 power generation plants, with an aggregate generation capacity of approximately 24,115 MW, and approximately 400 MW under construction which includes partner interests of 200 MW. In addition to its fossil fuel plant ownership, NRG has ownership interests in operating renewable facilities with an aggregate generation capacity of 365 MW, consisting of three wind farms representing an aggregate generation capacity of 345 MW (which includes partner interest of 75 MW) and a solar facility with an aggregate generation capacity of 20 MW. Within the U.S., NRG has large and diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 23,110 MW of fossil fuel and nuclear generation capacity in 179 active generating units at 42 plants. The Company s power generation facilities are most heavily concentrated in Texas (approximately 11,340 MW, including 345 MW from three wind farms), the Northeast (approximately 7,015 MW), South Central (approximately 2,855 MW), and West (approximately 2,150 MW, including 20 MW from a solar farm) regions of the U.S., with approximately 115 MW of additional generation capacity from the Company s thermal assets. In addition, through certain foreign subsidiaries, NRG has investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity.

On May 1, 2009, NRG acquired Reliant Energy, which is the second largest electricity provider to Mass customers in Texas. Reliant Energy is also the largest electricity and energy services provider, based on load, to C&I customers in Texas. Based on metered locations, as of December 31, 2009, Reliant Energy had approximately 1.5 million Mass customers and approximately 0.1 million C&I customers. Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service.

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 ASC 810, *Consolidations,* or ASC 810, to consolidate variable interest entities, or VIEs, for which the Company is the primary beneficiary. ASC 810 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.

As discussed in Note 16, *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 U.S. Upon its emergence from bankruptcy on December 5, 2003, the Company qualified for and adopted fresh start reporting, or Fresh Start, under ASC 852, *Reorganizations*, or ASC 852.

These financial statements and notes reflect the Company s evaluation of events occurring subsequent to the balance sheet date through February 23, 2010, the date the financial statements were issued.

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 by NRG as a result of collateral posting obligations from the Company s counterparties due to positions in NRG s hedging program. These amounts are segregated into separate accounts that are not contractually restricted but, based on the Company s intention, are not available for the payment of NRG s general corporate obligations. 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. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company s balance sheet, with an offsetting liability for this cash collateral received within current liabilities. 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 and Allowance for Doubtful Accounts

Trade receivables are reported in the balance sheet at outstanding principal adjusted for any write-offs and the allowance for doubtful accounts. For its Reliant Energy business, the Company accrues an allowance for doubtful accounts based on estimates of uncollectible revenues by analyzing counterparty credit ratings (for commercial and industrial customers), historical collections, accounts receivable aging and other factors. Reliant Energy writes-off accounts receivable balances against the allowance for doubtful accounts when it determines a receivable is uncollectible.

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 electricity or 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 cost of operations in the consolidated statements of operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with ASC 360. 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 ASC 323, 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 ASC 360 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, until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2009, 2008, and 2007, was $37 million, $45 million, and $11 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 customer contracts, customer relationships, energy supply contracts, trade names, emission allowances, 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 based on expected volumes, expected delivery, expected discounted future net cash flows, straight line or units of production basis.

Intangible assets determined to have indefinite lives are not amortized, but rather are tested for impairment at least annually or more frequently if events or changes in circumstances indicate that such acquired intangible assets have been determined to have finite lives and should now be amortized over their useful lives. NRG had no intangible assets with indefinite lives recorded as of December 31, 2009.

Emission allowances held-for-sale, which are included in other non-current assets on the Company s consolidated balance sheet, are not amortized; they are carried at the lower of cost or fair value and reviewed for impairment in accordance with ASC 360.

Goodwill

In accordance with ASC 350, 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 ASC 740, *Income Taxes*, or ASC 740, 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.

The Company accounts for uncertain tax positions in accordance with ASC 740, which applies to all tax positions related to income taxes. Under ASC 740, 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.

Revenue Recognition

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 ASC 815, *Derivatives and Hedging*, or ASC 815.

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 of emission allowances in excess of usage from the Company s emission bank to intangible assets held-for-sale for trading purposes. NRG records the sale of emission allowances on a net basis within other revenue in the Company s consolidated statements of operations.

Contract Amortization Assets and 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 (more) than market is amortized to revenue over the term of each underlying contract based on actual generation and/or contracted volumes.

Retail revenues Gross revenues for energy sales and services to Mass customers and to C&I customers are recognized upon delivery under the accrual method. Energy sales and services that have been delivered but not billed by period end are estimated. Gross revenues also includes energy revenues from resales of purchased power, which were $251 million for the eight-month period ended December 31, 2009. These revenues represent a sale of excess supply to third parties in the market.

As of December 31, 2009, Reliant Energy recorded unbilled revenues of $308 million for energy sales and services. Accrued unbilled revenues are based on Reliant Energy s estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

Cost of Energy for Reliant Energy

Reliant Energy records cost of energy for electricity sales and services to retail customers based on estimated supply volumes for the applicable reporting period. A portion of its cost of energy ($69 million as of December 31, 2009) consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities. In estimating supply volumes, Reliant Energy considers the effects of historical customer volumes, weather factors and usage by customer class. Reliant Energy estimates its transmission and distribution delivery fees using the same method that it uses for electricity sales and services to retail customers. In addition, Reliant Energy estimates ERCOT ISO fees based on historical trends, estimates supply volumes and initial ERCOT

ISO settlements. Volume estimates are then multiplied by the supply rate and recorded as cost of operations in the applicable reporting period.

Derivative Financial Instruments

NRG accounts for derivative financial instruments under ASC 815, which 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.

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 ASC 815, 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 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.

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, 2009, 2008, and

2007, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company s cumulative translation adjustment balances as of December 31, 2009, 2008, and 2007 were $21 million, $58 million and $59 million, respectively.

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, treasury repurchase agreements or government agency debt. Trust funds are held in accounts managed by experienced investment advisors. Certain 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, *Fair Value of Financial Instruments,* 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 5, *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, 2009, 2008, and 2007, the Company recorded an unrealized gain of $3 million, and impairment charges of $23 million and $11 million respectively, related to an investment in commercial paper. As of December 31, 2009 the net carrying value of the investment was $9 million.

Asset Retirement Obligations

NRG accounts for its asset retirement obligations, or AROs, in accordance with ASC 410-20, Asset *Retirement Obligations,* or ASC 410-20. Retirement obligations associated with long-lived assets included within the scope of ASC 410-20 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. ASC 410-20 requires 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. See Note 13, *Asset Retirement Obligations,* for a further discussion of AROs.

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. NRG accounts for pension and other postretirement benefits in accordance with ASC 715. 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.

NRG measures the fair value of its pension assets in accordance with ASC 820, *Fair Value Measurements and Disclosures*, or ASC 820.

Stock-Based Compensation

NRG accounts for its stock-based compensation in accordance with ASC 718. 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.

Issuance of Subsidiary s Stock

The Company accounts for issuance of its subsidiaries stock in accordance with ASC 810, which requires an entity to account for a decrease in its ownership interest of a subsidiary that does not result in a change of control of the subsidiary as an equity transaction. 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, as long as there is no change in control of NINA. Accordingly, receipt of TANE s installment contributions results in increases in additional paid in capital and noncontrolling interest on the Company s consolidated balance sheet.

Gross Receipts and Sales Taxes

In connection with its Reliant Energy business, the Company records gross receipts taxes on a gross basis in revenues and cost of operations in its consolidated statements of operations. During the eight-month period ended December 31, 2009, Reliant Energy s revenues and cost of operations included gross receipts taxes of $55 million. Additionally, Reliant Energy records sales taxes collected from its taxable customers and remitted to the various governmental entities on a net basis, thus, there is no impact on the Company s consolidated statement of operations.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

In recording transactions and balances resulting from business operations, NRG uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of 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

SFAS 168 In June 2009, the Financial Accounting Standards Board, or FASB, issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*, or SFAS 168. Effective July 1, 2009, this guidance establishes the FASB Accounting Standards Codification, or ASC, as the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. In addition, SFAS 168 also specifies that rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. All guidance contained in the ASC carries an equal level of authority. The Company adopted SFAS 168 for the quarterly reporting period ending September 30, 2009. SFAS 168 has been incorporated into the ASC as ASC-105, *Generally Accepted Accounting Principles,* or ASC 105.

Certain U.S. GAAP standards and interpretations were adopted by the Company in 2009 prior to the July 1, 2009, effective date of the ASC, and were subsequently incorporated into one or more ASC topics. Further, certain U.S. GAAP standards were ratified by the FASB in 2009 prior to July 1, 2009, but are not yet effective and have therefore not yet been incorporated into the ASC. This report retains the original title of these standards and interpretations, and references the ASC topic or topics in which they have been, or are expected to be, incorporated.

SFAS 141R The Company adopted SFAS No. 141 (revised 2007), *Business Combinations*, or SFAS 141R, on January 1, 2009. The provisions of SFAS 141R are applied prospectively to business combinations for which the acquisition date occurs after January 1, 2009. The statement requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. 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. In addition, transaction costs are required to be expensed as incurred. On May 1, 2009, NRG acquired all of the Texas electric retail business operations, or Reliant Energy, of Reliant Energy, Inc., now known as RRI. As discussed in Note 3, *Business Acquisitions*, to the Consolidated Financial Statements, the Company has applied the provisions of SFAS 141R to the Reliant Energy acquisition, as well as all other business acquisitions completed in 2009. As discussed further in Note 19, *Income Taxes*, any reductions after January 1, 2009, to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, as they relate to Fresh Start or previously completed acquisitions, will be recorded to income tax expense rather than additional paid-in capital or goodwill. SFAS 141R has been incorporated into ASC-805, *Business Combinations*, or ASC 805.

FSP FAS 141R-1 In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies*, or FSP FAS 141R-1, which the Company adopted effective January 1, 2009. This FSP amends and clarifies SFAS 141R, to address application issues on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. The provisions of FSP FAS 141R-1 are applied prospectively to assets or liabilities arising from contingencies in business combinations for which the acquisition date occurs after January 1, 2009. Accordingly, the Company has applied the provisions of FSP FAS 141R-1 to the Reliant Energy acquisition as well as all other business acquisitions completed in 2009. The provisions of FSP FAS 141R-1 have been incorporated into ASC 805.

SFAS 160 The Company adopted SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51, Consolidated Financial Statements*, or SFAS 160, on January 1, 2009. SFAS 160 establishes 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 is applied prospectively from the date of adoption, except for the presentation and disclosure requirements, which shall be applied retrospectively. Accordingly, the Company has conformed its financial statement presentation and disclosures to the requirements of SFAS 160. SFAS 160 has been incorporated into ASC-810, *Consolidation*, or ASC 810.

ASU No. 2010-02 - In January 2010 the FASB issued ASU No. 2010-02, *Consolidation (Topic 810): Accounting and Reporting for Decreases in Ownership of a Subsidiary a Scope Clarification,* or ASU 2010-02. ASU 2010-02 amends ASC 810, *Consolidation* to resolve a conflict between the consolidation guidance in the Accounting Standards Codification and other sections of U.S. GAAP when there is a decrease in ownership of a subsidiary. Entities are required to apply the amendments in ASU 2010-02 retrospectively for the first reporting period in which they applied SFAS 160. Although ASU 2010-02 is effective for the Company beginning in the fourth quarter of 2009, no decrease in ownership transactions resulting in a change in control within the scope of ASU 2010-02 and related guidance had occurred as of December 31, 2009, therefore there was no impact on the Company s results of operations, financial position, or cash flows.

FSP APB 14-1 The Company adopted 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, on January 1, 2009, applying it retrospectively to all periods presented. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) should separately account for the liability component and the equity component represented by the embedded conversion option in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Upon settlement, the entity shall allocate consideration transferred and transaction costs incurred to the extinguishment of the liability component and the reacquisition of the equity component. The provisions of FSP APB 14-1 have been incorporated into ASC-470, *Debt*, or ASC 470, and ASC-825, *Financial Instruments*, or ASC 825.

During the third quarter 2006, NRG s unrestricted wholly-owned subsidiaries CSF I and CSF II issued notes and preferred interests, or CSF Debt, which included embedded derivatives, or CSF CAGRs, requiring NRG to pay to CS at maturity, either in cash or stock at NRG s option, the excess of NRG s then current stock price over a threshold price. The CSF Debt and CSF CAGRs are accounted for under the guidance in ASC 470. Upon adoption of FSP APB 14-1, the fair value of the CSF CAGRs at the date of issuance was determined to be $32 million and has been recorded as a debt discount to the CSF Debt, with a corresponding credit to Additional Paid-in Capital. This debt discount will be amortized over the terms of the underlying CSF Debt. The cumulative effect of the change in accounting principle for periods prior to December 31, 2006, was recorded as a $28 million decrease to Long-Term Debt, a $32 million increase to Additional Paid-In Capital, and a $4 million decrease to Retained Earnings on the Condensed Consolidated Balance Sheet as of December 31, 2006. In addition, in August 2008 the Company paid $45 million to CS for the benefit of CSF I to early settle the CSF CAGR in the Company s CSF I notes and preferred interests, which was reclassified from interest expense to Additional Paid-In Capital upon the adoption of FSP APB 14-1.

The following table summarizes the effect of the adoption of FSP APB 14-1 on income and per-share amounts for all periods presented:

	For the Year Ended December 31,		
	2009	2008	2007
	(In millions, except per share amounts)		
Increase/(decrease):			
Interest Expense	$ 6	$ (37)	$ 13
Income From Continuing Operations	(6)	37	(13)
Net Income attributable to NRG Energy, Inc.	(6)	37	(13)
Basic Earnings Per Share	$ (0.03)	$ 0.16	$ (0.05)
Diluted Earnings Per Share	$ (0.02)	$ 0.14	$ (0.05)

FSP FAS 157-4 In April 2009, the FASB issued FSP No. FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* or FSP FAS 157-4. FSP FAS 157-4 provides additional guidance for estimating fair value in accordance with ASC-820, *Fair Value Measurements and Disclosure*, or ASC 820, when the volume and level of activity for the asset or liability have significantly decreased, includes guidance on identifying circumstances that indicate a transaction is not orderly, and requires disclosures about inputs and valuation techniques used to measure fair value. This FSP applies to all assets and liabilities within the scope of accounting pronouncements that require or permit fair value measurements. FSP FAS 157-4 is effective for interim and annual reporting periods ending after

June 15, 2009, and is applied prospectively. The Company s adoption of FSP FAS 157-4 beginning with the interim reporting period ended June 30, 2009, did not have a material impact on the Company s results of operations, financial position, or cash flows. The provisions of FSP FAS 157-4 have been incorporated into ASC 820.

FSP FAS 107-1 and APB 28-1 In April 2009, the FASB issued FSP No. FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments,* or FSP 107-1 and APB 28-1. This FSP requires disclosures about fair value of financial instruments for interim and annual reporting periods of publicly traded companies ending after the FSP s effective date of June 15, 2009. The Company s adoption of FSP FAS 107-1 and APB 28-1 beginning with the interim period ended June 30, 2009, did not have an impact on the Company s results of operations, financial position, or cash flows. The provisions of FSP FAS 107-1 and APB 28-1 have been incorporated in ASC-270, *Interim Reporting*, or ASC 270, and ASC-825, *Financial Instruments,* or ASC 825.

FSP FAS 115-2 and FAS 124-2 In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments,* or FSP FAS 115-2 and FAS 124-2. This FSP amends the other-than-temporary impairment guidance in U.S. GAAP for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP does not amend existing recognition and measurement guidance related to other-than-temporary impairments of equity securities. FSP FAS 115-2 and FAS 124-2 are effective for interim and annual reporting periods ending after June 15, 2009, and disclosure requirements apply only to periods ending after the FSP s effective date. The Company s adoption of FSP FAS 115-2 and FAS 124-2 beginning with the interim period ended June 30, 2009, did not have an impact on the Company s results of operations, financial position, or cash flows. The provisions of FSP FAS 115-2 and FAS 124-2 have been incorporated in ASC-320, *Investments Debt and Equity Securities*, or ASC 320.

SFAS 165 In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, or SFAS 165. SFAS 165 incorporates the accounting and disclosure requirements related to subsequent events found in auditing standards into U.S. GAAP, effectively making management directly responsible for subsequent events accounting and disclosures. SFAS 165 also requires disclosure of the date through which subsequent events have been evaluated. SFAS 165 is effective for interim and annual reporting periods ending after June 15, 2009, and shall be applied prospectively. The Company s adoption of SFAS 165 beginning with the interim period ended June 30, 2009, did not have an impact on the Company s results of operations, financial position, or cash flows. SFAS 165 has been incorporated in ASC-855, *Subsequent Events*, or ASC 855.

SFAS 167/ASU No. 2009-17 In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*, or SFAS 167. This guidance amends ASC 810 by altering how a company determines when an entity that is insufficiently capitalized or not controlled through its voting interests should be consolidated. The previous ASC 810 guidance required a quantitative analysis of the economic risk/rewards of a VIE to determine the primary beneficiary. FAS 167 now specifies that a qualitative analysis be performed, requiring the primary beneficiary to have both the power to direct the activities of a VIE that most significantly impact the entities economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. In December 2009 the FASB issued ASU No. 2009-17*, Consolidations: Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, or ASU 2009-17. ASU 2009-17 formally incorporates the provisions of SFAS 167 into ASC 810 and is effective for NRG as of January 1, 2010. The Company s adoption of ASU 2009-17 on January 1, 2010 did not have an impact on its results of operations, financial position, or cash flows.

ASU 2009-15/EITF 09-1 In July 2009, the FASB ratified EITF Issue No. 09-1, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing,* or EITF 09-1. This Issue applies to equity-classified share lending arrangements on an entity s own shares, when executed in contemplation of a convertible debt offering or other financing. EITF 09-1 addresses how to account for the share-lending arrangement and the effect, if any, that the loaned shares have on earnings-per-share calculations. The share lending arrangement is required to be measured at fair value and recognized as an issuance cost associated with the convertible debt offering or other financing. Earnings-per-share calculations would not be affected by the loaned shares unless the share borrower defaults on the arrangement and does not return the shares. If counterparty default is probable, the share lender is required to recognize an expense equal to the then fair value of the unreturned shares, net of the fair value of probable recoveries. The Company will apply EITF 09-1 for share lending agreements entered into after June 15, 2009, and will apply EITF 09-1 on a retrospective basis for arrangements outstanding as of January 1, 2010. This statement did not have a material impact on the Company s results of operations, financial position and cash flows. In October 2009, the FASB issued Accounting Standards Update, or ASU No. 2009-15, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing*, or ASU 2009-15, which formally incorporated the provisions of EITF 09-1 into ASC 470.

ASU 2009-05 In August 2009, the FASB issued ASU No. 2009-05, *Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value*, or ASU 2009-5. This ASU, which amends ASC 820 and ASC 825, provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. The Company s adoption of ASU 2009-5 beginning with the interim period ended September 30, 2009, did not have an impact on the Company s results of operations, financial position or cash flows.

ASU 2010-06 In January 2010, the FASB issued ASU No. 2010-06, *Fair Value Measurement and Disclosures: Improving Disclosures about Fair Value Measurements*, or ASU 2010-6, intending to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance is effective for interim and annual periods beginning after December 15, 2009 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard will not impact the Company s results of operations, cash flows or financial position.

Other The following accounting standards were adopted on January 1, 2009, with no impact on the Company s results of operations, financial position, or cash flows:

FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets,* which has been incorporated in ASC-275, *Risks and Uncertainties,* or ASC 275, and ASC-350, *Intangibles Goodwill and Other*, or ASC 350.

FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which has been incorporated in ASC 820.

SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities,* which has been incorporated in ASC-815, *Derivatives and Hedging,* or ASC 815.

FSP No. FAS 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets,* which has been incorporated in ASC-715, *Compensation-Retirement Benefits,* or ASC 715.

EITF No. 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock,* which has been incorporated in ASC 718, *Compensation-Equity Compensation,* or ASC 718, and ASC 815.

EITF No. 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement,* which has been incorporated in ASC 820.

EITF No. 08-6, *Equity Method Investment Accounting Considerations*, which has been incorporated in ASC-323, *Investments-Equity Method and Joint Ventures,* or ASC 323.

Note 3 Business Acquisitions

Acquisition of Reliant Energy

General

On May 1, 2009, NRG, through its wholly-owned subsidiary NRG Retail LLC, acquired Reliant Energy, which consisted of the entire Texas electric retail business operations of RRI, including the exclusive use of the trade name Reliant and related branding rights. Reliant Energy arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service. Reliant Energy is the second largest electricity provider to Mass customers in Texas, with approximately 1.5 million Mass customers as of December 31, 2009. Reliant Energy is also the largest electricity and energy services provider, based on load, to C&I customers in Texas with approximately 0.1 million C&I customers, based on metered locations as of December 31, 2009. These customers include refineries, chemical plants, manufacturing facilities, hospitals, universities, government agencies, restaurants, and other facilities.

With its complementary generation portfolio, the Texas region is a supplier of power to Reliant Energy, thereby creating the potential for a more stable, reliable and competitive business that benefits Texas consumers. By backing Reliant Energy s load-serving requirements with NRG s generation and risk management practices, the need to sell and buy power from other financial institutions and intermediaries that trade in the ERCOT market may be reduced, resulting in reduced transaction costs and credit exposures. This combination of generation and retail allows for a reduction in actual and contingent collateral, initially through offsetting transactions and over time by reducing the need to hedge the retail power supply through third parties. In addition, with Reliant Energy s base of retail customers, NRG now has a customer interface with the scale that is important to the successful deployment of consumer facing energy technologies and services.

Credit Support

On May 1, 2009, NRG arranged with Merrill Lynch Commodities, Inc. and certain of its affiliates, or Merrill Lynch, the former credit provider of RRI, to provide continuing credit support to Reliant Energy after closing the acquisition. In connection with entering into a transitional credit sleeve facility, or CSRA, NRG contributed $200 million of cash to Reliant Energy. In conjunction with the CSRA, NRG Power Marketing LLC, or PML, and Reliant Energy Power Supply LLC, or REPS, wholly-owned subsidiaries of NRG, modified or novated certain transactions with counterparties to transfer PML s in-the-money transactions to REPS and moved $522 million of cash collateral held by NRG to Merrill Lynch, thereby reducing Merrill Lynch s actual and contingent collateral supporting Reliant Energy out-of-money positions. Through October 5, 2009, these trades with counterparties were still open, thus there was no impact on NRG s consolidated financial statements, and NRG continued to record unrealized and realized gains/losses for these novated trades in its Texas and Northeast segments. The monthly fee for the CSRA was 5.875% on an annualized basis of the predetermined exposure.

Additionally, on May 1, 2009, NRG entered into a $50 million working capital facility with Merrill Lynch in connection with the acquisition of Reliant Energy. The facility required that the Company comply with all terms of the CSRA. NRG initially drew $25 million under the facility, which accrued interest at the prime rate. The $25 million outstanding under this facility was repaid, and the facility was terminated on October 5, 2009. See further discussion below.

Reliant Energy conducts its business through RERH Holdings, LLC and subsidiaries, or RERH, Reliant Energy Texas Retail, LLC, and Reliant Energy Services Texas, LLC. Through October 5, 2009, the obligations of Reliant Energy under the CSRA were secured by first liens on substantially all of the assets of RERH, and the obligations of RERH under the CSRA were non-recourse to NRG and its other non-pledgor subsidiaries.

The Company executed an amendment of the existing CSRA with Merrill Lynch, or CSRA Amendment, which became effective October 5, 2009. In connection with the CSRA Amendment, the Company recorded refinancing expense of $20 million in its results of operations for the year ended December 31, 2009, primarily related to the write-off of previously deferred financing costs. The CSRA Amendment removed the first liens associated with the CSRA, and RERH subsequently became a guarantor of the Company s obligations under its Senior Notes. See Note 29, *Condensed Consolidating Financial Information*, for further discussion of NRG s guarantees under its Senior Notes.

In connection with the CSRA Amendment, NRG net settled certain REPS transactions with counterparties and received $165 million in net cash consideration. Merrill Lynch returned $250 million of previously posted cash collateral and released liens on $322 million of unrestricted cash held at Reliant Energy. See Note 6, *Accounting for Derivative Instruments and Hedging Activities*, for the accounting impact of these settlements.

Pursuant to the CSRA Amendment, the Company was required to post collateral for any net liability derivatives and other static margin associated with supply for Reliant Energy. In connection with this amendment, NRG posted $366 million of cash collateral to Merrill Lynch and other counterparties, returned $53 million of counterparty collateral, issued letters of credit of $206 million, and received $45 million in counterparty collateral. The funds posted by the Company were sourced from a portion of the proceeds from the June 5, 2009 issuance of the 2019 Senior Notes. See Note 12, *Debt and Capital Leases*, for further discussion of the 2019 Senior Notes.

Under the amended CSRA, the parties had agreed to settle any outstanding wholesale obligations under the CSRA Amendment by January 29, 2010. As of that date, there was one remaining wholesale counterparty, for which NRG provided Merrill Lynch with a $10 million letter of credit to protect them from any potential liability. The parties continue to work to settle all outstanding obligations, including C&I counterparties, by April 30, 2010.

Acquisition method of accounting

The acquisition of Reliant Energy is accounted for under the acquisition method of accounting in accordance with ASC 805. Accordingly, NRG has conducted an assessment of net assets acquired and has recognized provisional amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred. The initial accounting for the business combination is not complete because the evaluations necessary to assess the fair values of certain net assets acquired and the amount of goodwill (if any) to be recognized are still in process. The provisional amounts recognized are subject to revision until the evaluations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments will affect the final balance of goodwill.

NRG paid RRI $287.5 million in cash at closing, funded from NRG s cash on hand. NRG also made payments to RRI of $78 million as remittances of acquired net working capital. In addition, the Company expects to remit approximately $4 million of acquired net working capital to RRI by the second quarter 2010, bringing the total cash consideration to approximately $370 million. NRG also recognized a $31 million non-cash gain on the settlement of a pre-existing relationship, representing the in-the-money value to NRG of an agreement that permits Reliant Energy to call on certain NRG gas plants when necessary for Reliant Energy to meet its load obligations. NRG has recorded this gain within Operating Revenues in its consolidated statement of operations. This non-cash gain is considered a component of consideration in accordance with ASC 805, and together with cash consideration, brings total consideration to approximately $401 million.

The following table summarizes the provisional values assigned to the net assets acquired, including cash acquired of $6 million, as of the acquisition date:

	(In millions)
Assets	
Current and non-current assets	$ 635
Property, plant and equipment	72

Intangible assets subject to amortization:	
In-market customer contracts	790
Customer relationships	399
Trade names	178
In-market energy supply contracts	54
Other	6
Derivative assets	1,942
Deferred tax asset, net	14
Goodwill	
Total assets acquired	$ 4,090

	(In millions)
Liabilities	
Current and non-current liabilities	$ 550
Derivative liabilities	2,996
Out-of-market energy supply and customer contracts	143
Total liabilities assumed	$ 3,689
Net assets acquired	$ 401

Current assets include accounts receivable with a preliminary fair value of $569 million and gross contractual amounts of $589 million at the time of acquisition. The Company has collected substantially all of the fair value of the contractual cash flows; any difference between fair value and the amount collected will be an adjustment to the acquired working capital payment due to RRI.

The Company, through its acquisition of Reliant Energy, is subject to material contingencies relating to Excess Mitigation Credits (see Note 22, *Commitments and Contingencies*) and Retail Replacement Reserve (see Note 23, *Regulatory Matters*). Due to the number of variables and assumptions involved in assessing the possible outcome of these matters, sufficient information does not exist to reasonably estimate the fair value of these contingent liabilities. These material contingencies have been evaluated in accordance with ASC-450, *Contingencies,* or ASC 450, and related guidance, and no provisional amounts for these matters have been recorded at the acquisition date. In addition, NRG provided certain indemnities in connection with the acquisition. See Note 26, *Guarantees,* for further discussion.

Measurement period adjustments

The following measurement period adjustments to the provisional amounts, attributable to refinement of the underlying appraisal assumptions, were recognized during 2009 subsequent to the acquisition date:

	Increase/(Decrease) (In millions)
Assets	
Intangible assets subject to amortization:	
In-market customer contracts	$ 57
Customer relationships	(82)
In-market energy supply contracts	17
Deferred tax asset, net	3
Total assets acquired	(5)
Liabilities	
Out-of-market energy supply and customer contracts	(5)
Total liabilities assumed	(5)

Net assets acquired	$

Fair value measurements

The provisional fair values of the intangible assets/liabilities and property, plant and equipment at the acquisition date were measured primarily based on significant inputs that are not observable in the market and thus represent a Level 3 measurement as defined in ASC 820. Significant inputs were as follows:

Customer contracts The fair values of the customer contracts, representing those with Reliant Energy s C&I customers, were estimated based on the present value of the above/below market cash flows attributable to the contracts based on contract type, discounted utilizing a current market interest rate consistent with the overall credit quality of the portfolio. The fair values also accounted for Reliant Energy s historical costs to acquire customers. The above/below market cash flows were estimated by comparing the expected cash flows to be generated based on existing contracted prices and expected volumes with the cash flows from estimated current market contract prices for the same expected volumes. The estimated current market contract prices were derived considering current market costs, such as price of energy, transmission and distribution costs, and miscellaneous fees, plus a normal profit margin. The customer contracts are amortized to revenues, over a weighted average amortization period of five years, based on expected volumes to be delivered for the portfolio.

Customer relationships The customer relationships, reflective of Reliant Energy s Mass customer base, were valued using a variation of the income approach. Under this approach, the Company estimated the present value of expected future cash flows resulting from the existing customer relationships, considering attrition and charges for contributory assets (such as net working capital, fixed assets, software, workforce and trade names) utilized in the business, discounted at an independent power producer peer group s weighted average cost of capital. The customer relationships are amortized to depreciation and amortization expense, over a weighted-average amortization period of eight years, based on the expected discounted future net cash flows by year.

Trade names The trade names were valued using a relief from royalty method, an approach under which fair value is estimated to be the present value of royalties saved because NRG owns the intangible asset and therefore does not have to pay a royalty for its use. The trade names were valued in two parts based on Reliant Energy s two primary customer segments Mass customers and C&I customers. The avoided royalty revenues were discounted at an independent power producer peer group s weighted average cost of capital. The remaining useful life of the trade names were determined by considering various factors, such as turnover and name changes in the independent power producer and utility industries, the current age of the Reliant brand, management s intent to continue using the name at the current time, and feedback from external consultants regarding their experience with similar trade names. The trade names are amortized to depreciation and amortization expense, on a straight-line basis, over 15 years.

Energy supply contracts The fair values of the in-market and out-of-market energy supply contracts were determined in accordance with ASC 820. These contracts are amortized over periods ranging through 2016, based on the expected delivery under the respective contracts.

Property, plant and equipment The fair value of property, plant and equipment was valued using a cost approach, which estimates value by determining the current cost of replacing an asset with another of equivalent economic utility. The cost to replace a given asset reflects the estimated reproduction or replacement cost for the property, less an allowance for loss in value due to depreciation.

The fair values of derivative assets and liabilities as of the acquisition date were determined in accordance with ASC 820. The breakdown of Level 1, 2 and 3 is as follows:

	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Derivative assets	$ 534	$ 1,375	$ 33	$ 1,942
Derivative liabilities	$ 534	$ 2,357	$ 105	$ 2,996

Amortization of acquired intangible assets and out-of-market contracts

See Note 11, *Goodwill and Other Intangibles*, for the estimated remaining amortization related to acquired intangible assets and out-of-market contracts, including Customer contracts, Customer relationships, Trade names and Energy supply contracts, for 2010 2014.

Supplemental Pro-Forma Information

Since the acquisition date, Reliant Energy contributed $4.2 billion of operating revenues and $1.0 billion in net income attributable to NRG. See Note 18, *Segment Reporting*, for more information on the Company s segment results.

The following supplemental pro-forma information represents the results of operations as if NRG and Reliant Energy had combined at the beginning of the respective reporting periods:

	For the Year Ended December 31,	
	2009	2008
	(In millions, except per share amounts)	
Operating revenues	$ 10,799	$ 15,124
Net income attributable to NRG Energy, Inc.	945	419
Earnings per share attributable to NRG common stockholders:		
Basic	$ 3.71	$ 1.55
Diluted	$ 3.45	$ 1.48

The supplemental pro-forma information has been adjusted to include the pro-forma impact of amortization of intangible assets and out-of-market contracts, and depreciation of property, plant and equipment, based on the preliminary purchase price allocations. The pro-forma data has also been adjusted to eliminate the non-recurring transaction costs incurred by NRG. Transactions between NRG and Reliant Energy have not been eliminated. The pro-forma results are presented for illustrative purposes only and do not reflect the realization of potential cost savings, or any related integration costs. Certain cost savings may result from the acquisition; however, there can be no assurance that these cost savings will be achieved.

Other Acquisitions

The Company also completed the following acquisitions during the fourth quarter of 2009, for combined consideration totaling $68 million:

Bluewater Wind LLC On November 9, 2009, NRG, through its wholly-owned subsidiary NRG Bluewater Holdings LLC, acquired all the subsidiaries of Bluewater Wind LLC (such subsidiaries, together with NRG Bluewater Holdings LLC, NRG Bluewater). NRG Bluewater, a developer of off-shore wind energy, has a number of projects that are in various stages of development along the eastern seaboard and the Great Lakes region of the U.S.

FSE Blythe 1, LLC On November 20, 2009, NRG, through its wholly owned subsidiary NRG Solar LLC, acquired FSE Blythe 1, LLC, or Blythe Solar, from First Solar, Inc. On December 18, 2009, construction was completed and commercial operations began for Blythe Solar s 20 MW utility-scale photovoltaic, or PV, solar facility located in Riverside County in southeastern California. The Blythe Solar PV field provides electricity to Southern California Edison under a 20-year PPA.

Note 4 Discontinued Operations and Dispositions

Discontinued Operations

NRG classifies material business operations and gains/(losses) recognized on sales as discontinued operations for businesses that were sold or have met the required criteria for such classification. ASC 360 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 ASC 360, the Company s management considers cash flow analyses, bids, and offers related to those assets and businesses. In accordance with the provisions of ASC 360, assets held by discontinued operations are not depreciated commencing with their classification as such.

NRG s discontinued operations reflect the disposal of ITISA, reported in the Company s international segment. On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V, 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. The Company recorded a pre-tax gain on the disposal of ITISA of $273 million in the year ended December 31, 2008. Summarized results of ITISA, reflected within discontinued operations for the years ended December 31, 2008, and 2007, were as follows:

	Year Ended December 31,	
	2008	2007
	(In millions)	
Operating revenues	$ 20	$ 50
Operating costs and other expenses	9	27
Pre-tax income from operations of discontinued components	11	23
Income tax expense	3	6
Income from operations of discontinued components	8	17
Disposal of discontinued components pre-tax gain	273	
Income tax expense	109	
Gain on disposal of discontinued components, net of income taxes	164	
Income from discontinued operations, net of income taxes	$ 172	$ 17

Other Dispositions

MIBRAG On June 10, 2009, NRG completed the sale of its 50% ownership interest in Mibrag B.V. to a consortium of Severoćeské doly Chomutov, a member of the CEZ Group, and J&T Group. Mibrag B.V. s principal holding was MIBRAG, which was jointly owned by NRG and URS Corporation. As part of the transaction, URS Corporation also entered into an agreement to sell its 50% stake in MIBRAG.

For its share, NRG received EUR 203 million ($284 million at an exchange rate of 1.40 U.S.$/EUR), net of transaction costs. During the year ended December 31, 2009, NRG recognized an after-tax gain of $128 million. Prior to completion of the sale, NRG continued to record its share of MIBRAG s operations to Equity in earnings of unconsolidated affiliates.

In connection with the transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. The foreign currency forward contract had a fixed exchange rate of 1.277 and required NRG to deliver EUR 200 million in exchange for $255 million on June 15, 2009. For the year ended December 31, 2009, NRG recorded an exchange loss of $24 million on the contract within Other (loss)/income, net. NRG provided certain indemnities in connection with its share of the transaction. See Note 26, *Guarantees*, for further discussion.

Red Bluff and Chowchilla On January 3, 2007, NRG completed the sale of the Company s Red Bluff and Chowchilla II power plants to an entity controlled by Wayzata Investment Partners LLC. These power plants, located in California, are fueled by natural gas, with generating capacity of 45 MW and 49 MW, respectively.

Note 5 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	
	2009	2008	2009	2008
	(In millions)			
Cash and cash equivalents	$ 2,304	$ 1,494	$ 2,304	$ 1,494
Funds deposited by counterparties	177	754	177	754
Restricted cash	2	16	2	16
Cash collateral paid in support of energy risk management activities	361	494	361	494
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	9	7	9	7
Marketable equity securities	5	2	5	2

	Year Ended December 31,			
	Carrying Amount		Fair Value	
	2009	2008	2009	2008
	(In millions)			
Trust fund investments	369	305	369	305
Notes receivable	231	156	238	166
Derivative assets	2,319	5,485	2,319	5,485
Long-term debt, including current portion	8,295	8,019	8,211	7,475
Cash collateral received in support of energy risk management activities	177	760	177	760
Derivative liabilities	$ 1,860	$ 4,489	$ 1,860	$ 4,489

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 U.S. debt and equity securities carried at fair market value.

The fair value of notes receivable, debt securities and certain long-term debt are based on expected future cash flows discounted at market interest rates. The fair value of 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.

Fair Value Accounting under ASC 820

ASC 820 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 ASC 820, 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, 2009:

	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Cash and cash equivalents	$ 2,304	$	$	$ 2,304
Funds deposited by counterparties	177			177
Restricted cash	2			2
Cash collateral paid in support of energy risk management activities	361			361
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities			9	9
Marketable equity securities	5			5
Trust fund investments	214	118	37	369
Derivative assets	489	1,767	63	2,319
Total assets	$ 3,552	$ 1,885	$ 109	$ 5,546
Cash collateral received in support of energy risk management activities	$ 177	$	$	$ 177
Derivative liabilities	501	1,283	76	1,860
Total liabilities	$ 678	$ 1,283	$ 76	$ 2,037

The following table reconciles, for the year ended December 31, 2009, the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements at least annually using significant unobservable inputs:

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)			
	Debt Securities	Trust Fund Investments	Derivatives[a]	Total
	(In millions)			
Beginning balance as of January 1, 2009	$ 7	$ 31	$ 49	$ 87
Total gains and losses (realized/unrealized):				
Included in OCI	2			2

Included in earnings			(97)	(97)
Included in nuclear decommissioning obligations		9		9
Purchases/(sales), net		(3)	1	(2)
Transfers, out of Level 3			34	34
Ending balance as of December 31, 2009	$ 9	$ 37	$ (13)	$ 33
The amount of the total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held as of December 31, 2009	$	$	$ 25	$ 25

(a) Consists of derivatives assets and liabilities, net.

Realized and unrealized gains and losses included in earnings that are related to the energy derivatives are recorded in operating revenues and cost of operations.

Non-derivative fair value measurements

NRG s investment in debt securities are classified as Level 3 and consist of non-traded debt instruments that are valued based on third-party market value assessments.

The trust fund investments are held primarily to satisfy NRG s nuclear decommissioning obligations. These trust fund investments hold debt and equity securities directly and equity securities indirectly through commingled funds. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. In addition, U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized in Level 2. Commingled funds, which are analogous to mutual funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair value of commingled funds are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares in the commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See also Note 7, *Nuclear Decommissioning Trust Fund.*

Derivative fair value measurements

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. A significant portion of the fair value of the Company s derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate those transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represents 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 3% 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 uses the counterparty s default swap rate. If the exposure under a specific master agreement is a liability, the Company uses 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, 2009, the credit reserve resulted in a $1 million increase in fair value which is composed of a $1 million loss in OCI and a $2 million gain in derivative revenue and cost of operations.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2009, 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.

Under the guidance of ASC 815, entities may choose to offset cash collateral paid or received against the fair value of derivative positions executed with the same counterparties under the same master netting agreements. The Company has chosen not to offset positions as defined in ASC 815. As of December 31, 2009, the Company recorded $361 million of cash collateral paid and $177 million of cash collateral received on its balance sheet.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, *Summary of Significant Accounting Policies*, the following item is a discussion of the concentration of credit risk for the Company s financial instruments. 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, prepayment arrangements, or volumetric limits (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 nine 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.

Since the credit crisis began in late 2008, NRG has taken several additional steps to mitigate credit risk including the use of netting arrangements, entering contracts with collateral thresholds, setting volumetric limits with certain counterparties and restricting trading relationships with counterparties where exposure was high or where credit quality of the counterparty had deteriorated. 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, 2009, total credit exposure to substantially all counterparties was $1.3 billion and NRG held collateral (cash and letters of credit) against those positions of $186 million resulting in a net exposure of $1.1 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 exposure 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 NPNS, and non-derivative transactions. The exposure is shown net of collateral held, includes amounts net of receivables or payables.

Category	**Net Exposure (a) as of December 31, 2009 (% of Total)**
Financial institutions	69%
Utilities, energy merchants, marketers and other	25
Coal suppliers	3
ISOs	3
Total as of December 31, 2009	100%

Net Exposure (a)
as of December 31,
2009

Category	**(% of Total)**
Investment grade	90%
Non-rated	8
Non-Investment grade	2
Total as of December 31, 2009	100%

(a) Credit exposure excludes California tolling, uranium, coal transportation, New England RMR, certain cooperative load contracts, and Texas Westmoreland coal contracts. The aforementioned exposures were excluded for various reasons including regulatory support or liens held against the contracts which serve to reduce the risk of loss, or credit risks for certain contracts are not readily measurable due to a lack of market reference prices.

NRG has credit risk exposure to certain counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $351 million. Approximately 82% of NRG s positions relating to credit risk roll-off by the end of 2012. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company s financial position or results of operations from nonperformance by any of NRG s counterparties.

NRG is exposed to retail credit risk through its competitive electricity supply business, which serves C&I customers and the Mass market in Texas. Retail credit risk results when a customer fails to pay for services rendered. The losses could be incurred from nonpayment of customer accounts receivable and any in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of December 31, 2009, the Company s credit exposure to C&I customers was diversified across many customers and various industries. No one customer represented more than 2% of total exposure and the majority of the customers have investment grade credit quality, as determined by NRG.

NRG is also exposed to credit risk relating to its 1.5 million Mass customers, which may result in a write-off of a bad debt. The current economic conditions may affect the Company s customers ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Note 6 Accounting for Derivative Instruments and Hedging Activities

ASC 815 requires NRG to recognize all derivative instruments on the balance sheet as either assets or liabilities and to measure them at fair value each reporting period unless they qualify for a Normal Purchase Normal Sale, or NPNS, exception. If certain conditions are met, NRG may be able to designate certain derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives to OCI until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

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

For derivatives that are not designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Under the guidelines established per ASC 815, certain derivative instruments may qualify for the NPNS exception and are therefore exempt from fair value accounting treatment. ASC 815 applies to NRG s energy related commodity contracts, interest rate swaps, and foreign exchange contracts.

As the Company engages principally in the trading and marketing of its generation assets and retail business, some of NRG s commercial activities qualify for hedge accounting under the requirements of ASC 815. In order for the generation assets to qualify, the physical generation and sale of electricity should be highly probable at inception of the trade and throughout the period it is held, as is the case with the Company s baseload plants. For this reason, many trades in support of NRG s baseload units normally qualify for NPNS or cash flow hedge accounting treatment, and trades in support of NRG s peaking units asset optimization will generally not qualify for hedge accounting treatment, with any changes in fair value likely to be reflected on a mark-to-market basis in the statement of operations. Most of the retail load contracts either qualify for the NPNS exception or fail to meet the criteria for a derivative and the majority of the supply contracts are recorded under mark-to-market accounting. All of NRG s hedging and trading activities are in accordance with the Company s Risk Management Policy.

Energy-Related Commodities

To manage the commodity price risk associated with the Company s competitive supply activities and the price risk associated with wholesale and retail power sales from the Company s electric generation facilities, NRG may enter into a variety of derivative and non-derivative hedging instruments, utilizing the following:

Forward contracts, which commit NRG to sell or purchase energy commodities or purchase fuels in the future.

Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.

- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual, or notional, quantity.
- Option contracts, which convey the right or obligation to purchase or sell a commodity.
- Weather and hurricane derivative products used to mitigate a portion of Reliant Energy s lost revenue due to weather.

The objectives for entering into derivative contracts designated as hedges include:

- Fixing the price for a portion of anticipated future electricity sales through the use of various derivative instruments including gas collars and swaps at a level that provides an acceptable return on the Company s electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of NRG s power plants.
- Fixing the price of a portion of anticipated energy purchases to supply Reliant Energy s customers.

NRG s trading activities 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.

As of December 31, 2009, NRG had hedge and non-hedge energy-related derivative financial instruments, and other energy-related contracts that did not qualify as derivative financial instruments extending through December 2026. As of December 31, 2009, NRG s derivative assets and liabilities consisted primarily of the following:

- Forward and financial contracts for the purchase/sale of electricity and related products economically hedging NRG s generation assets forecasted output or NRG s retail load obligations through 2015.
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG s generation assets into 2017.

Also, as of December 31, 2009, NRG had other energy-related contracts that qualified for the NPNS exception and were therefore exempt from fair value accounting treatment under the guidelines established by ASC 815 as follows:

- Power sales and capacity contracts extending to 2025.

Also, as of December 31, 2009, NRG had other energy-related contracts that did not qualify as derivatives under the guidelines established by ASC 815 as follows:

- Load-following forward electric sale contracts extending through 2026;
- Power Tolling contracts through 2029;
- Lignite purchase contract through 2018;
- Power transmission contracts through 2015;

Natural gas transportation contracts and storage agreements through 2018; and

Coal transportation contracts through 2016.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company s issuance of variable and fixed rate debt. In order to manage the Company s interest rate risk, NRG enters into interest-rate swap agreements. As of December 31, 2009, NRG had interest rate derivative instruments extending through June 2019, all of which had been designated as either cash flow or fair value hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG s derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of December 31, 2009. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

Commodity	**Units**	**Total Volume as of December 31, 2009 (In millions)**
Emissions	Short Ton	(2)
Coal	Short Ton	55
Natural Gas	MMBtu	(484)
Oil	Barrel	1
Power[(a)]	MWH	(41)
Interest	Dollar	$ 3,291

(a) *Power volumes include capacity sales.*

Fair Value of Derivative Instruments

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company s derivative assets or liabilities are recorded on a separate line item on the balance sheet. The Company has chosen not to offset positions as defined in ASC 815. As of December 31, 2009, the Company recorded $361 million of cash collateral paid and $177 million of cash collateral received on its balance sheet. The following table summarizes the fair value within the derivative instrument valuation on the balance sheet as of December 31, 2009:

	Fair Value	
	Derivatives Asset	**Derivatives Liability**
	(In millions)	
Derivatives Designated as Cash Flow or Fair Value Hedges:		
Interest rate contracts current	$	$ 2
Interest rate contracts long-term	8	106
Commodity contracts current	300	12
Commodity contracts long-term	508	6
Total Derivatives Designated as Cash Flow or Fair Value Hedges	816	126
Derivatives Not Designated as Cash Flow or Fair Value Hedges:		
Commodity contracts current	1,336	1,459
Commodity contracts long-term	167	275
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	1,503	1,734

Total Derivatives	$	2,319	$	1,860

Impact of Derivative Instruments on the Statement of Operations

The following table summarizes the amount of gain/(loss) resulting from fair value hedges reflected in interest income/(expense) for interest rate contracts:

Amount of gain/(loss) recognized	**Years Ended December 31, 2009 (In millions)**
Derivative	$ (6)
Senior Notes (hedged item)	$ 6

The following table summarizes the location and amount of gain/(loss) resulting from cash flow hedges:

Year ended December 31, 2009	Amount of gain recognized in OCI (effective portion) after tax		Location of gain/(loss) reclassified from Accumulated OCI into Income	Amount of gain/(loss) reclassified from Accumulated OCI into Income (In millions)		Location of gain/(loss) recognized in income (ineffective portion)	Amount of gain recognized in income (ineffective portion)	
Interest rate contracts	$	36	Interest expense	$	1	Interest expense	$	4
Commodity contracts		55	Operating revenue		(472)	Operating revenue		45
Total	$	91		$	(471)		$	49

The following table summarizes the amount of gain/(loss) recognized in income for derivatives not designated as cash flow or fair value hedges on commodity contracts:

Amount of gain/(loss) recognized in income or cost of operations for derivatives	Year ended December 31, 2009 (In millions)	
Location of gain/(loss) recognized in income for derivatives:		
Operating revenues	$	(335)
Cost of operations	$	842

Credit Risk Related Contingent Features

Certain of the Company s hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed adequate assurance under the agreements. Other agreements contain provisions that require the Company to post additional collateral if there was a one notch downgrade in the Company s credit rating. The collateral required for out-of-the-money positions and net accounts payable for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2009, was $80 million. The collateral required for out-of-the-money positions and net accounts payable for contracts with credit rating contingent features that are in a net liability position as of December 31, 2009, was $49 million. The Company is also a party to certain marginable agreements where NRG has a net liability position but the counterparty has not called for the collateral due, which is approximately $3 million as of December 31, 2009.

As of January 29, 2010, Merrill Lynch was no longer providing credit support for any wholesale energy supply contracts relating to the retail business. Merrill Lynch continues to provide guaranties to certain C&I customers as part of the credit sleeve arrangement. If Merrill Lynch were to default, NRG would be required to post guaranties to replace Merrill.

See Note 5, *Fair Value of Financial Instruments*, for discussion regarding concentration of credit risk.

Accumulated Other Comprehensive Income

The following table summarizes the effects of ASC 815 on NRG s accumulated OCI balance attributable to hedged derivatives, net of tax:

Year ended December 31, 2009	**Energy Commodities**	**Interest Rate**	**Total**
		(In millions)	
Accumulated OCI balance at December 31, 2008	$ 406	$ (91)	$ 315
Realized from OCI during the period:			
- Due to realization of previously deferred amounts	(335)	1	(334)
- Due to discontinuance of cash flow hedge accounting	(137)		(137)
Mark-to-market of cash flow hedge accounting contracts	527	35	562
Accumulated OCI balance at December 31, 2009	$ 461	$ (55)	$ 406
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $123 tax	$ 213	$ (3)	$ 210

Year ended December 31, 2008	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2007	$ (234)	$ (31)	$ (265)
Realized from OCI during the period:			
- Due to realization of previously deferred amounts		(1)	(1)
Mark-to-market of cash flow hedge accounting contracts	640	(59)	581
Accumulated OCI balance at December 31, 2008	$ 406	$ (91)	$ 315

Year ended December 31, 2007	Energy Commodities	Interest Rate	Total
		(In millions)	
Accumulated OCI balance at December 31, 2006	$ 193	$ 16	$ 209
Realized from OCI during the period:			
- Due to realization of previously deferred amounts	(50)	(2)	(52)
Mark-to-market of cash flow hedge accounting contracts	(377)	(45)	(422)
Accumulated OCI balance at December 31, 2007	$ (234)	$ (31)	$ (265)

As of December 31, 2009, the net balance in OCI relating to ASC 815 was an unrecognized gain of approximately $406 million, which is net of $247 million in income taxes. As of December 31, 2008, the net balance in OCI relating to ASC 815 was an unrecognized gain of approximately $315 million, which was net of $194 million in income taxes.

Accounting guidelines require a high degree of correlation between the derivative and the hedged item throughout the period in order to qualify as a cash flow hedge. As of July 31, 2008, the Company s regression analysis for natural gas prices to ERCOT power prices, while positively correlated, did not meet the required threshold for cash flow hedge accounting for calendar years 2012 and 2013. As a result, the Company de-designated its 2012 and 2013 ERCOT cash flow hedges as of July 31, 2008 and prospectively marked these derivatives to market. On April 1, 2009, the required correlation threshold for cash flow hedge accounting was achieved for these transactions, and accordingly, these hedges were re-designated as cash flow hedges.

As discussed in Note 3, *Business Acquisitions*, in conjunction with the CSRA, PML and REPS modified or novated certain transactions with counterparties. The novated transactions are financial sales of natural gas to the counterparties covering the period from 2009 through 2012 to hedge NRG s Texas baseload generation. A portion of these transactions were accounted for as cash flow hedges. The effective portion of the fair value of these transactions recorded in OCI was approximately $247 million. On the date of novation, NRG elected to de-designate these cash flow hedges and to recognize future changes in value in earnings prospectively. As the underlying baseload power generation is still probable, the gains through the date of novation related to the cash flow hedges remain frozen in OCI and will be amortized into income when the underlying power is generated. Approximately $240 million of the fair values of these transactions at the novation date were accounted for as mark-to-market transactions through the income statement both before and after the novations.

As also discussed in Note 3, *Business Acquisitions*, on October 5, 2009, the Company amended the CSRA with Merrill Lynch. In connection with the CSRA amendment, NRG net settled certain REPS out-of-money supply transactions with Merrill Lynch and paid $104 million in consideration. In addition, NRG net settled certain in-the-money REPS transactions with Morgan and received $269 million in consideration. As noted above, the in-the-money transaction was previously novated by NRG s wholly owned subsidiary PML to REPS. As these transactions were net settled, the $245 million in OCI will continue to be frozen and will be amortized into income when the underlying power from the baseload plants are generated and the balance of $24 million of previously recorded unrealized revenue was recorded as a loss of $24 million in unrealized derivative revenue and a $24 million gain in realized or financial revenue. The net settlement on the Merrill Lynch transactions resulted in a realized loss of $104 million and an unrealized gain of $104 million due to the reversal of an unrealized loss.

Statement of Operations

In accordance with ASC 815, unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedge derivatives and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activity on NRG s statement of operations. These amounts are included within operating revenues and cost of operations.

	Year ended December 31, 2009	Year ended December 31, 2008
	(In millions)	
Unrealized mark-to-market results		
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$ (68)	$ (38)
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	656	
Reversal of previously recognized unrealized gains on settled positions related to trading activity	(157)	(32)
Reversal of previously recognized unrealized losses due to the termination of positions related to the CSRA unwind	80	
Net unrealized gains on open positions related to economic hedges	22	524
Gains/(losses) on ineffectiveness associated with open positions treated as cash flow hedges	45	(24)
Net unrealized (losses)/gains on open positions related to trading activity	(26)	95
Total unrealized gains	$ 552	$ 525

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(In millions)	
Revenue/(expense) from operations - energy commodities	$ (290)	$ 525
Cost of operations	842	
Total impact to statement of operations	$ 552	$ 525

The $22 million gain from economic hedge positions includes a gain of $217 million recognized in earnings from previously deferred amounts in OCI as the Company discontinued cash flow hedge accounting for certain 2009 transactions in Texas and New York due to lower expected generation, offset by a loss of $29 million resulting from discontinued NPNS designated coal purchases due to expected lower coal consumption and accordingly could not assert taking physical delivery and a $166 million decrease in value of forward purchases and sales of natural gas, electricity and fuel due to decrease in forward power and gas prices.

The Reliant Energy s loss positions were acquired as of May 1, 2009, and valued using forward prices on that date. The $656 million roll-off amounts were offset by realized losses at the settled prices and are reflected in revenue and cost of operations during the same period.

For the year ended December 31, 2008, the unrealized gain associated with changes in the fair value of derivative instruments not accounted for as hedge derivatives of $525 million was comprised of $524 million of fair value increases in forward sales of electricity and fuel, a $24 million loss due to the ineffectiveness associated with financial forward contracted electric and gas sales, $70 million from the reversal of mark-to-market gains which ultimately settled as financial and physical revenues of which $38 million was related to economic hedges and $32 million was related to trading activity. These decreases were partially offset by $95 million of gains associated with open positions related to trading activity.

Discontinued Hedge Accounting - During the first half of 2009, a relatively sharp decline in commodity prices resulted in falling power prices and lower power generation for the remainder of 2009. As such, NRG discontinued cash flow hedge accounting for certain 2009 contracts previously accounted for as cash flow hedges. These contracts were originally entered into as hedges of forecasted sales by baseload plants in Texas and Northeast. As a result, $217 million of gain previously deferred in OCI was recognized in earnings for the year ended December 31, 2009.

Discontinued Normal Purchase and Sale for Coal Purchases - Due to lower coal-fired generation during the first quarter 2009, the Company s coal consumption was lower than forecasted. The Company net settled some of its coal purchases under NPNS designation and thus was no longer able to assert physical delivery under these coal contracts. The forward positions previously treated as accrual accounting have been reclassified into mark-to-market accounting during the first quarter and prospectively. The impact of discontinuance of coal NPNS designated transactions resulted in a derivative loss of $29 million that is reflected in the cost of operations for the year ended December 31, 2009.

Note 7 Nuclear Decommissioning Trust Fund

NRG s nuclear decommissioning trust fund assets, which are for the decommissioning of STP, are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. Although NRG is responsible for managing the decommissioning of its 44% interest in STP, the predecessor utilities that owned STP are authorized by the PUCT to collect decommissioning funds from their ratepayers to cover decommissioning costs on behalf of NRG. NRC requirements determine the decommissioning cost estimate which is the minimum required level of funding. In the event that funds from the ratepayers that accumulate in the nuclear decommissioning trust are ultimately determined to be inadequate to decommission the STP facilities, the utilities will be required to collect through rate base all additional amounts, with no obligation from NRG, provided that NRG has complied with PUCT rules and regulations regarding decommissioning trusts. Following completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective ratepayers of the utilities.

NRG accounts for the nuclear decommissioning trust fund in accordance with ASC 980 *Regulated Operations*, or ASC 980 because the Company s nuclear decommissioning activities are subject to approval by the PUCT, with regulated rates that are designed to recover all decommissioning costs and that can be charged to and collected from the ratepayers per PUCT mandate. Since the Company is in compliance with PUCT rules and regulations regarding decommissioning trusts and the cost of decommissioning is the responsibility of the Texas ratepayers, not NRG, all realized and unrealized gains or losses (including other-than-temporary impairments) related to the Nuclear Decommissioning Trust Fund are recorded to the Nuclear Decommissioning Trust Liability to the ratepayers and are not included in net income or accumulated other comprehensive income, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses (including other-than-temporary impairments) for the securities held in the trust funds as of December 31, 2009 and 2008, as well as information about the contractual maturities of those securities. The cost of securities sold is determined on the specific identification method.

	As of December 31, 2009				As of December 31, 2008		
	Fair Value	Unrealized gains	Unrealized losses	Weighted-average maturities (years)	Fair Value	Unrealized gains	Unrealized losses
	(In millions, except otherwise noted)						
Cash and cash equivalents	$ 4	$	$		$ 2	$	$

U.S. government and federal agency obligations	23	1		19	21	2	
Federal agency mortgage-backed securities	60	2		23	49	2	
Commercial mortgage-backed securities	10		1	29	16		4
Corporate debt securities	48	3	1	10	37	1	2
Marketable equity securities	220	89	2		178	41	6
Foreign government fixed income securities	2			6			
Total	$ 367	$ 95	$ 4		$ 303	$ 46	$ 12

The following tables summarize proceeds from sales of available-for-sale securities and the related realized gains and losses from these sales. The cost of securities sold is determined on the specific identification method.

	Year ended December 31, 2009	2008	2007
	(In millions)		
Realized gains	$ 2	$ 11	$ 6
Realized losses	(1)	(33)	(1)
Proceeds from sale of securities	279	582	233

Note 8 Inventory

Inventory consists of:

	As of December 31, 2009	2008
	(In millions)	
Fuel oil	$ 104	$ 128
Coal/Lignite	288	189
Natural gas	9	11
Spare parts	137	127
Other	3	
Total Inventory	$ 541	$ 455

Note 9 Capital Leases and Notes Receivable

Notes receivable primarily consists of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. NRG s notes receivable and capital leases as of December 31, 2009, and 2008 were as follows:

	As of December 31, 2009	2008
	(In millions)	
Capital Leases Receivable non-affiliates		
VEAG Vereinigte Energiewerke AG, due August 31, 2021, 11.00%[a]	$ 301	$ 338
Other	5	9
Capital Leases non-affiliates	306	347
Notes Receivable affiliates		
GenConn Energy LLC, due April 30, 2009, LIBOR + 3.75%[b] current		36

Kraftwerke Schkopau GBR, indefinite maturity date, 6.91%-7.00%[c] non-current	122	120
GCE Holding LLC which wholly-owns GenConn Energy LLC, indefinite maturity date, LIBOR +3%[d]	108	
Notes receivable affiliates	230	156
Subtotal Capital leases and notes receivable	536	503
Less current maturities:		
Capital leases	32	32
Notes receivable GenConn		36
Subtotal current maturities	32	68
Total Capital leases and notes receivable noncurrent	$ 504	$ 435

(a) Saale Energie GmbH, or SEG, has sold 100% of its share of capacity from the Schkopau power plant to VEAG Vereinigte Energiewerke AG under a 25-year contract, which is more than 83% of the useful life of the plant. This direct financing lease receivable amount was calculated based on the present value of the income to be received over the life of the contract.

(b) In 2008, NRG entered into a short-term $45 million note receivable facility with GenConn Energy LLC to fund project liquidity needs.

(c) SEG entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between Saale and E.On Kraftwerke GmbH. The note was used to fund SEG s initial capital contribution to the partnership and to cover project liquidity shortfalls during construction of the Schkopau power plant. The note is subject to repayment upon the disposition of the Schkopau plant.

(d) NRG entered into a long-term $121.6 million note receivable facility with GCE Holding LLC to fund project liquidity needs.

Note 10 Property, Plant, and Equipment

NRG s major classes of property, plant, and equipment as of December 31, 2009 and 2008 were as follows:

	As of December 31, 2009	As of December 31, 2008	Depreciable Lives
	(In millions)		
Facilities and equipment	$ 13,023	$ 12,193	1-40 Years
Land and improvements	621	593	
Nuclear fuel	286	225	5 Years
Office furnishings and equipment	153	73	2-10 Years
Construction in progress	533	804	
Total property, plant and equipment	14,616	13,888	
Accumulated depreciation	(3,052)	(2,343)	
Net property, plant and equipment	$ 11,564	$ 11,545	

Note 11 Goodwill and Other Intangibles

Goodwill NRG s goodwill arose in connection with the acquisitions of Texas Genco and Padoma Wind Power LLC. As of December 31, 2009 and 2008, goodwill was approximately $1.7 billion. In accordance with ASC 805, goodwill associated with the Texas Genco acquisition decreased by $68 million during 2008 due to an adjustment to deferred tax liabilities originally established under the 2006 purchase price allocation. Goodwill is not amortized but instead tested for impairment in accordance with ASC 350 at the reporting-unit level. Goodwill is tested annually, typically during the fourth quarter, or more often if events or circumstances, such as adverse changes in the business climate, indicate there may be impairment. As of December 31, 2009, there was no impairment to goodwill. As of December 31, 2009 and 2008, NRG had approximately $721 million and $786 million, respectively, of goodwill that is deductible for U.S. income tax purposes in future periods.

Intangible Assets The Company s intangible assets as of December 31, 2009 reflect intangible assets acquired from the acquisition of Bluewater Wind and Blythe Solar in November 2009, the acquisition of Reliant Energy in May 2009, the acquisition of Texas Genco in February 2006 and the adoption of Fresh Start accounting.

For the Reliant Energy acquisition, the intangible assets include energy supply contracts, customer contracts, customer relationships, trade names, and other. The energy supply contracts consist of in-market and out-of-market contracts that are amortized based on the expected delivery under the respective contracts. The amortization expense associated with the energy supply contracts is recorded as part of cost of operations. The customer contracts are amortized to revenues, based on expected volumes to be delivered for the portfolio. The customer relationships are amortized to depreciation and amortization expense, based on the expected discounted future cash flow by year. The trade names are amortized to depreciation and amortization expense on a straight line basis over the estimated useful life.

The intangible assets established with the Texas Genco acquisition and upon the adoption of Fresh Start reporting include SO_2 and NO_x emission allowances and certain in-market power, fuel (coal, gas, and nuclear) and water contracts. The emission allowances are amortized and recorded as a part of the cost of operations, with NO_x emission allowances amortized on a straight line basis and SO_2 emission allowances amortized based on units of production. The power contracts are amortized based on contracted volumes over the life of each contract and the fuel contracts are amortized over expected volumes over the life of each contract. The power contracts are amortized and recorded as part of revenues, while fuel and water contracts are amortized and recorded as part of the cost of operations.

In 2009, NRG began purchasing RGGI emission allowance credits, which are amortized based on units of production and recorded as a part of the costs of operations.

The following tables summarize the components of NRG s intangible assets subject to amortization for the years ended December 31, 2009 and 2008:

December 31, 2009	Emission Allowances	Contracts Power	Contracts Energy Supply	Contracts Fuel	Contracts Customer	Customer Relationships	Trade Names	Other	Total
				(In millions)					
January 1, 2009	$ 916	$ 58	$	$ 171	$	$	$	$ 5	$ 1,150
Write-off of fully amortized intangible assets	(19)	(58)		(88)					(165)
Acquisition of businesses			54		790	399	178	11	1,432
Reclassification of NPNS contract to derivative				(12)					(12)
Other	22							(2)	20
Adjusted gross amount	919		54	71	790	399	178	14	2,425
Less accumulated amortization[a]	(199)		(18)	(48)	(258)	(117)	(8)		(648)
Net carrying amount	$ 720	$	$ 36	$ 23	$ 532	$ 282	$ 170	$ 14	$ 1,777

(a) Includes annual amortization expense as described in the table below; netting of fully amortized intangible assets of $19 million and $58 million for emission allowances and power contracts, respectively; and decrease of accumulated amortization expense of $88 million as a result of the reclassification of NPNS contract to derivatives in fuel contracts.

December 31, 2008	Emission Allowances	Contracts Power	Contracts Fuel	Contracts Water	Other	Total
			(In millions)			
January 1, 2008	$ 916	$ 92	$ 171	$ 64	$ 2	$ 1,245
Additions	6				3	9
Transfer to held for sale	(6)					(6)
Fully amortized intangible assets		(34)		(64)		(98)
Adjusted gross amount	916	58	171		5	1,150
Less accumulated amortization	(155)	(58)	(122)			(335)
Net carrying amount	$ 761	$	$ 49	$	$ 5	$ 815

The following table presents NRG s amortization of intangible assets for the years ended December 31, 2009, 2008 and 2007: