NRG ENERGY, INC.
Form 10-K
March 07, 2006

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

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the Fiscal Year ended December 31, 2005.**
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the Transition period from to .**

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

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

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

Title of Each Class	Name of Exchange on Which Registered
5.75% Mandatorily Convertible Preferred Stock	New York Stock Exchange

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

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

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

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

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

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer 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 $3,272,968,478 based on the closing sale price of $37.60 as reported on the New York Stock Exchange.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes þ No o

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

Class	Outstanding at March 3, 2006
Common Stock, par value $0.01 per share	136,975,275

Documents Incorporated by Reference:
Portions of the Proxy Statement for the 2006 Annual Meeting of Stockholders to be held on April 28, 2006

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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:

APB	Accounting Principles Board
APB 18	APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock.*
Average gross heat rate	The product of dividing(a) fuel consumed in BTU s by(b) KWh generated.
BART	Best Available Retrofit Technology
Baseload capacity	Electric power generation capacity normally expected to serve loads on an around-=the-clock basis throughout the calendar year.
BTA	Best Technology Available
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
Cal ISO	California Independent System Operator.
CAMR	Clean Air Mercury Rule
Capacity factor	The ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CL&P	Connecticut Light & Power
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission,
CTDEP	Connecticut Department of Environmental Protection
CWA	Clean Water Act
DNREC	Delaware Department of Natural Resources and Environmental Control
EAF	The total available hours a unit is available in a year minus the sum of all partial outage events in a year converted to equivalent hours, expressed as a percent of all hours in the year
EFOR	Equivalent Forced Outage Rates considers the equivalent impact that forced de-ratings have in addition to full forced outages
EITF	Emerging Issues Task Force
EITF 91-6	EITF No. 91-6, *Revenue Recognition of Long-Term Power Sales Contracts.*
EITF 02-3	EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*
EITF 03-11	EITF Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in EITF Issue No. 02-03.*
EPA	Environmental Protection Agency

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ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ERISA	Employee Retirement Income Security Act
Expected annual baseload generation	The net baseload capacity limited by economic factors (relationship between cost of generation and market price) and reliability factors (scheduled and unplanned outages)
FASB	Financial Accounting Standards Board, the designated organization for establishing standards for financial accounting and reporting
FERC	Federal Energy Regulatory Commission
FF-ACI	Fabric Filter with Activated Carbon Injection
FGD	Flue Gas Desulphurization
FIN	Financial Accounting Standards Board Interpretation
FIN 45	FIN No. 45 *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.*
FIN 46R	FIN No. 46 (Revised 2003), *Consolidation of Variable Interest Entities*
FIP	Federal Implementation Plan
Fresh Start	Reporting requirements as defined by SOP 90-7
FSP	FASB Staff Position (interpretations of standards issued by the staff of the FASB)
FSP 106-1	FSP 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*
FSP 106-2	FSP 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*
GHG	Greenhouse Gases
IGCC	Integrated Gasification Combined Cycle
IRS	Internal Revenue Service
ISO	Independent System Operator, also referred to as regional transmission organizations, or RTO
ISO-NE	ISO New England, Inc.
KWh	kilowatt-hours
LADEQ	Louisiana Department of Environmental Quality
LIBOR	London Inter-Bank Offered Rate
LNB/OFA	Low NO_x Burner with Over Fire Air
MACT	Maximum Achievable Control Technology
MADEP	Massachusetts Department of Environmental Protection
Moody s	Moody s Investors Services, Inc.
MISO	Midwest Independent Transmission System Operator
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NAAQS	National Ambient Air Quality Standards
Net baseload capacity	Nominal summer net megawatt capacity of power generation adjusted for ownership and parasitic load, and excluding capacity from mothballed units as of December 31, 2005

Net Capacity Factor	Net actual generation divided by net maximum capacity for the period hours
Net Generating Capacity	Nominal summer capacity, net of auxiliary power
NiMo	Niagara Mohawk Power Corporation
NO_x	Nitrogen oxides
NOL	Net operating loss
NRC	United States Nuclear Regulatory Commission
NSR	New Source Review
NYISO	New York Independent System Operator.
NYSDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
OTC	Ozone Transport Commission
PJM	PJM Interconnection, LLC
PJM Market	The wholesale and retail electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia.
$PM_{2.5}$	Fine particulate matter
PSD	Prevention of Significant Deterioration
PUCT	Public Utility Commission of Texas
Powder River Basin, or PRB Coal	Coal produced in the northeastern Wyoming and southeastern Montana, which coal has low sulfur content
RCRA	Resource Conservation and Recovery Act
RECLAIM	Regional Clean Air Incentives Market
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability must-run
RTC	RECLAIM Trading Credit
RTO	Regional transmission organization
S&P	Standard & Poor s, a division of the McGraw Hill Companies
SARA	Superfund Amendments and Reauthorization Act of 1986
Sarbanes-Oxley	Sarbanes Oxley Act of 2002
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SDG&E	San Diego Gas & Electric
SEC	United States Securities and Exchange Commission
SERC	Southeastern Electric Reliability Council/ Entergy
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS 71	SFAS No. 71 *Accounting for the Effects of Certain Types of Regulation*
SFAS 87	SFAS No. 87, *Employers Accounting for Pensions*
SFAS 106	SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*
SFAS 109	SFAS No. 109, *Accounting for Income Taxes*
SFAS 123	SFAS No. 123, *Accounting for Stock-Based Compensation*
SFAS 123R	SFAS No. 123 (revised 2004), *Share-Based Payment*
SFAS 133	SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*

SFAS 140	SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, a replacement of FASB Statement 125*
SFAS 142	SFAS No. 142, *Goodwill and Other Intangible Assets*
SFAS 143	SFAS No. 143, *Accounting for Asset Retirement Obligations*
SFAS 144	SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SOP	Statement of Position issued by the American Institute of Certified Public Accountants
SOP 90-7	Statement of Position 90-7 *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*
SPP	Southwest Power Pool
STP	South Texas Project Texas Genco s nuclear generating facility located in Bay City, TX of which we own a 44% interest
TCEQ	Texas Commission on Environmental Quality
Texas Genco	Texas Genco LLC
US	United States of America
USEPA	US Environmental Protection Agency
US GAAP	Accounting principles generally accepted in the US
WCP	WCP (Generation) Holdings, Inc.

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PART I

Item 1 *Business*

For purposes of discussing our business in this Business Section of our Annual Report, we, our, us, the combined company and the Company refer to NRG and Texas Genco on a combined basis, together with their consolidated subsidiaries, after giving effect to the completion of the acquisition of Texas Genco, or the Acquisition. The terms MW and MWh refer to megawatts and megawatt-hours. The megawatt figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the combined company s ownership position excluding capacity from inactive/mothballed units as of December 31, 2005. NRG has previously shown gross MWs when presenting its operations. Capacity is tested following standard industry practices. The combined company s numbers denote saleable MWs net of internal/parasitic load. The term expected annual baseload generation refers to the net baseload capacity limited by economic factors (relationship between cost of generation and market price) and reliability factors (scheduled and unplanned outages).

General

We are a leading wholesale power generation company with a significant presence in many of the major competitive power markets in the United States. We are primarily engaged in the ownership and operation of power generation facilities, purchasing fuel and transportation services to support our power plant operations, and marketing and trading energy, capacity and related products in the competitive markets in which we operate.

On February 2, 2006, NRG acquired Texas Genco LLC by purchasing all of the outstanding equity interests in Texas Genco. The purchase price of approximately $6.1 billion consisted of approximately $4.4 billion in cash and the issuance of approximately 35.4 million shares of NRG s common stock valued at approximately $1.7 billion, and we assumed a total of approximately $2.7 billion of Texas Genco s outstanding debt. The purchase price is subject to adjustment due to acquisition costs. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

As of December 31, 2005, the combined company has a total global portfolio of 235 operating generation units at 61 power generation plants, with an aggregate generation capacity of approximately 24,580 MW. Within the United States, the combined company has a large and geographically diversified power generation portfolio with approximately 22,663 MW of generation capacity in 213 generating units at 53 plants. These power generation facilities are primarily located in our core regions in the ERCOT market (approximately 10,658 MW), and in the Northeast (approximately 7,099 MW), South Central (approximately 2,395 MW) and Western (approximately 1,044 MW) regions of the United States. Our facilities consist primarily of baseload, intermediate and peaking power generation facilities, and also include thermal energy production and energy resource recovery plants. The sale of capacity and power from baseload generation facilities accounts for the majority of our revenues and provides a stable source of cash flow. In addition, our diverse generation portfolio provides us with opportunities to capture additional revenues by selling power into our core regions 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 December 27, 2005, we entered into a definitive agreement with Dynegy, Inc., to acquire Dynegy s 50% of WCP. When completed this acquisition will give NRG sole ownership of WCP s 1,800 MW of generation capacity in California. Our disclosures as to MWs and financial information do not include the remaining 50% interest in WCP.

Our Strategy

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

Increase value from our existing assets. We have a highly diversified portfolio of power generation assets in terms of region, fuel type and dispatch levels. We will continue to focus on extracting value from our portfolio by improving plant performance, reducing costs and harnessing our advantages of scale in the procurement of fuels: a strategy that we have branded *FOR*NRG, or Focus on ROIC@NRG.

Pursue intrinsic growth opportunities at existing sites in our core regions. We are favorably positioned to pursue growth opportunities through expansion of our existing generating capacity. We intend to invest in our existing assets through plant improvements, repowering and brownfield development to meet anticipated regional requirements for new capacity. We expect that these efforts will provide more efficient energy, lower our delivered cost, expand our electricity production capability and improve our ability to dispatch economically across sectors of the merit order, including baseload, intermediate and peaking generation.

Maintain financial strength and flexibility. We remain focused on increasing cash flow and maintaining liquidity and balance sheet strength in order to ensure continued access to capital for growth; enhancing risk-adjusted returns; and providing flexibility in executing our business strategy. We will continue our focus on maintaining operational and financial controls designed to ensure that our financial position remains strong.

Reduce the volatility of our cash flows through asset-based commodity hedging activities. We will continue to execute asset-based risk management, hedging, marketing and trading strategies within well-defined risk and liquidity guidelines in order to manage the value of our physical and contractual assets. Our marketing and hedging philosophy is centered on generating stable returns from our portfolio of power generation assets while preserving the ability to capitalize on strong spot market conditions and to capture the extrinsic value of our portfolio. We believe that we can successfully execute this strategy by taking advantage of our expertise in the trading and marketing of power and ancillary services, our knowledge of markets, our flexible financial structure and our diverse portfolio of power generation assets.

Participate in continued industry consolidation. We will continue to pursue selective acquisitions, joint ventures and divestitures to enhance our asset mix and competitive position in our core regions to meet the fuel and dispatch requirements in these regions. We intend to concentrate on acquisition and joint venture opportunities that present attractive risk-adjusted returns. We will also opportunistically pursue other strategic transactions, including mergers, acquisitions or divestitures during the consolidation of the power generation industry in the United States.

Our Competitive Strengths

Scale and diversity of assets. The combined company has one of the largest and most diversified power generation portfolios in the United States with approximately 22,663 MW of generation capacity in 213 generating units at 53 plants as of December 31, 2005. Our power generation assets are diversified by fuel type, dispatch level and region, which helps mitigate the risks associated with fuel price volatility and market demand cycles. The combined company s U.S. baseload facilities consist of approximately 8,558 MW of generation capacity and provide the combined company with a significant source of stable cash flow, while the combined company s intermediate and peaking facilities, with approximately 14,105 MW of generation capacity, provide the combined company with opportunities to capture the significant upside potential that can arise from time to time during periods of high demand. In addition, approximately 10% of the combined company s domestic generation facilities have dual or multiple fuel capability, which allows most of these plants to dispatch with the lowest cost fuel option.

The following chart demonstrates the diversification of the combined company s generation assets:

(1) Reflects only domestic generation capacity; 19 MW of wood-fired generation capacity not shown.

Stability of future cash flows. We have sold forward a significant amount of our expected baseload generation capacity for 2006 and 2007. As of December 31, 2005 the company has sold forward an average of 77% of its baseload generation in the Texas (ERCOT) market for 2006 through 2009. As of the same date, the combined company sold an average of 78% of its expected annual baseload generation in the SERC Entergy market for 2006 through 2009, and approximately 76% of its expected annual baseload generation in the Northeast region for 2006. In addition, as of December 31, 2005, the combined company purchased forward under fixed price fuel contracts (with contractually-specified price escalators) to provide fuel for approximately 81% of its expected baseload coal generation output from 2006 to 2009.

Favorable market dynamics for baseload power plants. As of December 31, 2005, approximately 39% of the company s domestic generation capacity has been fueled by coal or nuclear fuel. In many of the competitive markets where we operate, the price of power typically is set by the marginal costs of natural gas-fired and oil-fired power plants. These oil and gas fired plants currently have substantially higher variable costs than our solid fuel baseload power plants. As a result of our lower marginal cost for baseload coal and nuclear generation assets, we expect such assets to generate power nearly 100% of the time they are available.

Locational advantages. Many of our generation assets are located within densely populated areas that are characterized by significant constraints on the transmission of power from generators outside the region. Consequently, these assets are able to benefit from the higher prices that prevail for energy in these markets during periods of transmission constraints. The Company has generation assets located within New York City, southwestern Connecticut, Houston and the Los Angeles and San Diego load basins, all areas with constraints on the transmission of electricity. This allows us to capture additional revenues through offering capacity to retail electric providers and other entities serving load within the transmission constrained areas, selling power at prevailing market prices during periods of peak demand and providing ancillary services in support of system reliability.

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Performance Metrics

The following table contains a summary of NRG s North American power generation revenues from majority-owned subsidiaries for the year 2005 (figures for our Texas facilities are not included):

Region	Energy Revenues	Capacity Revenues	Alternative Energy Revenues	O&M Fees	Other Revenues***	Total Revenues
			(In millions)			
Northeast	$ 1,444	$ 291	$	$	$ (181)	$ 1,554
South Central	330	186			36	552
Western*	1					1
Other	11	5	2		(3)	15
Total North America Power Generation**	$ 1,786	$ 482	$ 2	$	$ (148)	$ 2,122

* Consists of our wholly-owned subsidiary, NEO California LLC. Does not include revenues which were produced by assets in which we have a 50% equity interest, primarily West Coast Power, and are reported under the equity method of accounting.

** For additional information see Item 15 Note 21 of the Consolidated Financial Statements for our consolidated revenues by segment disclosures.

*** Includes miscellaneous revenues from the sale of natural gas, recovery of incurred costs under reliability must-run agreements, revenues received under leasing arrangements, revenues from maintenance, revenues from the sale of ancillary services and revenues from entering into certain financial transactions, offset by contract amortization.

In understanding our business, we believe that certain performance metrics are particularly important. These are industry statistics defined by the North American Electric Reliability Council and are more fully described below:

Annual Equivalent Availability Factor, or EAF: is the total available hours a unit is available in a year minus the sum of all partial outage events in a year converted to equivalent hours (EH), where EH is partial megawatts lost divided by unit net available capacity times hours of each event, and the net of these hours is divided by hours in a year to achieve EAF in percent.

Average gross heat rate: We calculate the average heat rate for our fossil-fired power plants by dividing (a) fuel consumed in Btus by (b) KWh generated. The resultant heat rate is a measure of fuel efficiency.

Net Capacity Factor: Net actual generation divided by net maximum capacity for the period hours.

The tables below present the North American power generation performance metrics for owned assets discussed above for the years ended December 31, 2005 and December 31, 2004 (figures for our Texas facilities are not included):

	Year Ended December 31, 2005		
	Net Generation	Annual Equivalent Availability	Average Net Heat Rate

Region	Net Owned Capacity (MW)	(MWh)	Factor	Btu/KWh	Net Capacity Factor
Northeast*	7,099	15,251,449	87.2%	11,146	22.9%
South Central	2,395	10,116,622	90.9%	10,518	50.6%
Western**	1,044	1,588,962	86.5%	11,109	18.0%
Other North America	1,467	247,721	90.6%	14,297	3.4%

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	Year Ended December 31, 2004				
Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/KWh	Net Capacity Factor
Northeast*	7,099	13,205,040	85.6%	10,823	19.8%
South Central	2,395	10,470,786	92.1%	10,494	52.9%
Western**	1,044	2,291,844	88.4%	10,624	25.6%
Other North America***	1,467	147,376	97.3%	N/A	2.4%

* Net Generation and the other metrics do not include Keystone and Conemaugh.
** Includes 50% of the generation owned through our West Coast Power partnership.
*** Excludes operations for Kendall, McClain and Batesville which were sold during 2004.

The tables below present the Australian power generation performance metrics discussed above for the years ended December 31, 2005 and December 31, 2004:

	Year Ended December 31, 2005				
Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Net Heat Rate Btu/KWh	Net Capacity Factor
Flinders Northern Power Station	480	3,990,642	95.8%	10,900	94.9%
Flinders Playford Power Station	220	458,180	57.9%	15,900	23.8%
Gladstone*	605	2,808,335	93.3%	10,300	53.0%

	Year Ended December 31, 2004				
	Net Owned	Net Generation	Annual Equivalent Availability	Average Net Heat Rate	Net Capacity

Region	**Capacity (MW)**	**(MWh)**	**Factor**	**Btu/KWh**	**Factor**
Flinders Northern Power Station	480	3,924,196	93.2%	11,400	93.1%
Flinders Playford Power Station	220	365,642	46.0%	16,300	18.9%
Gladstone*	605	2,879,236	83.2%	10,200	54.2%

* Includes 37.5% of the generation owned through our Gladstone Unincorporated Joint Venture.

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Generation Asset Overview

We have a significant power generation presence in many of the major competitive power markets of the United States as set out below:

Texas (ERCOT)

As of December 31, 2005, Texas Genco s generation assets in the ERCOT market consisted of approximately 5,178 MW of baseload generation assets and approximately 5,480 MW of intermediate, cyclic and peaking natural gas-fired assets. We expect that the combined company will realize a substantial majority of its revenue and cash flow from the sale of power from its three baseload power plants located in the ERCOT market that use solid fuel: W. A. Parish (coal), Limestone (lignite and PRB coal) and an undivided 44% interest in two nuclear generation units at STP (nuclear fuel). Because plants are generally dispatched in order of lowest operating cost, and approximately 73% of the net generation capacity in the ERCOT market was natural gas-fired, we expect these three baseload plants to operate nearly 100% of the time (subject to planned and forced outages) due to their low marginal costs relative to natural gas-fired plants.

The following table summarizes the ERCOT baseload forward power sales and natural gas swap agreements that extend beyond December 31, 2005. The amounts summarized below reflect forward sales volumes and average prices as of December 31, 2005:

	2006	2007	2008	2009	2010	Annual Average for 2006-2007	Annual Average for 2006-2010
Net Baseload Capacity (MW)	5,294	5,340	5,340	5,340	5,340	5,317	5,331
Total Baseload Sales (MW)(1)	4,375	4,267	4,157	3,449	1,395	4,321	3,529
Percentage Baseload Capacity Sold Forward	83%	80%	78%	65%	26%	81%	66%
Weighted Average Forward Price ($ per MWh)(2)	$ 44	$ 39	$ 41	$ 47	$ 51	$ 41	$ 43
Total Revenues Sold Forward ($ in millions)(2)	$ 1,690	$ 1,443	$ 1,505	$ 1,434	$ 621	$ 1,566	$ 1,338

(1) Includes amounts under fixed price firm and non-firm power sales contracts and amounts financially hedged under natural gas swap contracts. The forward natural gas swap quantities are reflected in equivalent MW and are derived by first dividing the quantity of MMBtu of natural gas hedged by the forward market heat rate (in MMBtu/MWh, mid-point of the bid and offer as quoted by

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brokers in the market of the relevant Electric Reliability Council of Texas zones as of December 30, 2005) to arrive at the equivalent MWh hedged which is then divided by 8,760 to arrive at MW hedged.

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

Northeast

As of December 31, 2005, approximately 7,099 MW of NRG s generation capacity consisted of power plants in the Northeast region of the United States, including power plants within the control areas of the New York Independent System Operator, or NYISO, the ISO-New England, Inc., or ISO-NE, and the PJM Interconnection LLC., or PJM. Certain of these assets are located in transmission constrained areas, including approximately 1,394 MW of in-city New York City generation capacity and approximately 538 MW of southwest Connecticut generation capacity. As of December 31, 2005, NRG s generation assets in the Northeast region consisted of approximately 1,876 MW of baseload generation assets and approximately 5,223 MW of intermediate and peaking assets.

The following table summarizes Northeast s baseload forward power sales that extend beyond December 31, 2005. The amounts summarized below reflect forward sales volumes and average prices as of December 31, 2005:

	2006	2007	2008	2009	2010	Annual Average for 2006-2007
Net Baseload Capacity (MW)	1,876	1,876	1,876	1,876	1,876	1,876
Total Baseload Sales (MW)	1,410	608				1,009
Percentage Baseload Capacity Sold Forward	75%	32%	%	%	%	54%
Weighted Average Forward Price ($ per MWh)	$ 72	$ 76	$	$	$	$ 74
Total Revenues Sold Forward ($ in millions)	$ 885	$ 406	$	$	$	$ 645

South Central

As of December 31, 2005, NRG owned approximately 2,395 MW of generation capacity in the South Central region of the United States, making NRG the third largest generator in the Southeastern Electric Reliability Council/ Entergy, or SERC-Entergy, region. NRG s generation assets in the South Central region consisted of approximately 1,489 MW of baseload generation assets and 906 MW of intermediate and peaking assets. NRG s primary asset is the Big Cajun II coal-fired plant near Baton Rouge, where NRG has approximately 1,489 MW of generation capacity.

The following table summarizes South Central s baseload forward power sales that extend beyond December 31, 2005. The amounts summarized below reflect forward sales volumes and average prices as of December 31, 2005:

	2006	2007	2008	2009	2010	Annual Average for 2006-2007	Annual Average for 2006-2010
Net Baseload Capacity (MW)	1,489	1,489	1,489	1,489	1,489	1,489	1,489
Total Baseload Sales (MW)(1)	1,150	1,097	1,088	1,015	1,008	1,124	1,072
Percentage Baseload Capacity Sold Forward	77%	74%	73%	68%	68%	75%	72%

Weighted Average Forward Price ($ per MWh)	$	33	$	32	$	33	$	34	$	36	$	33	$	34
Total Revenues Sold Forward ($ in millions)	$	307	$	308	$	314	$	303	$	316	$	307	$	310

(1) Total Baseload Sales volumes for South Central are estimated volumes using historical load information.

Western

As of December 31, 2005, NRG s assets in the Western Electricity Coordinating Council, or WECC, the power market for the West Coast of the United States, included approximately 1,044 MW of generation capacity, most of it in NRG s 50% interest in WCP Holdings. NRG s generation assets in the Western region consisted of approximately 1,044 MW of intermediate and peaking assets. As part of NRG s strategy of optimizing NRG s asset base, NRG retired approximately 265 MW of additional gross generation capacity at the Long Beach generating facility on January 1, 2005. On December 27, 2005, NRG entered into a purchase and sale agreement to acquire Dynegy s 50% ownership interest in WCP Holdings to become the sole owner of power plants totaling approximately 1,800 MW of generation capacity in the Western region. On March 1, 2006, FERC issued an order authorizing the transaction, pursuant to section 203 of the Federal Power Act.

Australia

As of December 31, 2005, NRG owned approximately 1,305 MW of coal fired, primarily base load generation plants in the Australian National Electricity Market (NEM) 700 MW in the South Australian region (NRG Flinders) and 605 MW in the Queensland Region (Gladstone). NRG Flinders is a merchant generation business that derives revenue from bidding its output into the NEM, by trading the plant as a portfolio, selling derivative hedges that are not plant specific and supplying minor retail sales via contract. 180 MW of gas fired power contracted from Osborne under a long-term PPA is also traded as part of the portfolio. A hedge book is maintained such that the short to medium term revenue is secured via hedge levels up to and in the order of 75-80% of the plant output. The current book is underpinned by a medium term hedge with a major South Australian retailer. The Gladstone assets are owned through an unincorporated joint venture with other investors and NRG does not have unilateral control over management of the assets. Gladstone Power Station is fully contracted through 2029 via a PPA and a capacity purchase agreement with Boyne Smelter Limited and Enertrade, respectively. Enertrade is a state owned company that trades the excess power in the NEM.

Other

As of December 31, 2005, NRG had net ownership in approximately 1,467 MW of additional generating capacity in the United States. In addition to these traditional power generation facilities, NRG also owns thermal and chilled water businesses that generate approximately 1,225 MW thermal equivalents, as well as resource recovery facilities, as described below. NRG also owns interests in power plants having a generation capacity of approximately 611 MW from a hydro plant in Brazil and coal plants adjacent to our coal mines in Germany.

Power Marketing and Commercial Operations

We seek 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 credits, fuel supplies and transportation-related services. Our principal objectives are the realization of the full market value of our asset base, including the capture of extrinsic value, the management and mitigation of commodity market risk, and the reduction of cash flow volatility over time.

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

Before NRG acquired it, Texas Genco s capital structure permitted the grant of second priority liens on its assets as security for Texas Genco s obligations under certain long-term power sales agreements and related hedges. The Credit Agreement for NRG s senior secured debt and the Indentures for NRG s high yield notes, which became effective as of February 2, 2006, allow these arrangements to remain in place. In addition, the new debt instruments also permit us to grant second priority liens on our other assets in the United States in order to secure obligations under power sales agreements and related hedges, within certain limits. The seven trading counterparties of Texas Genco who held second priority liens on Texas Genco s assets as of

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February 2, 2006, have been offered a second priority lien on NRG s other assets under the new structure, as additional collateral. Going forward, NRG anticipates that it will use the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under long term power sales and related hedges.

As of February 28, 2006, our net mark-to-market exposure on the hedges that are subject to the second lien structure was $1.9 billion. The following table summarizes the utilization of the second lien structure as of December 31, 2005:

	12 Months Starting				
	Jan 1, 2006	**Jan 1, 2007**	**Jan 1, 2008**	**Jan 1, 2009**	**Jan 1, 2010**
Equivalent Net Sales secured by Second Lien Structure(1)					
In MWh	2,081	3,067	2,513	2,999	1,395
As a percentage of net baseload capacity in collateral pool as of February 2, 2006	30%	44%	36%	43%	20%

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

Our largest customer under the second lien structure is J. Aron & Co., or J. Aron. The agreements with J. Aron extend through December 31, 2010, and account for approximately 26% of NRG s baseload generation in Texas and approximately 16% of our total baseload capacity, as measured in MWh through 2010.

In addition to the second lien described above, NRG also provides cash collateral and letters of credit to secure its obligations under hedge agreements and other power marketing contracts. As of December 31, 2005, the combined company, after giving effect to the Acquisition, had posted cash collateral (including letters of credit) to support commercial operations totaling $1.2 billion. The following table summarizes, as of December 31, 2005, the combined company collateral posted by credit rating.

Credit Rating	**Letters of Credit**	**Cash**	**Collateral Posted**
		(In millions)	
A and above	$ 616	$ 392	$ 1,008
BBB through BBB+	99	39	138
Below BBB-	7	4	11
Not Rated(1)	38	3	41
Total	$ 760	$ 438	$ 1,198

(1) Not Rated indicates that no rating has been issued, or that an external rating agency (for example, Standard & Poor s or Moody s) does not rate a particular obligation as a matter of policy. The Not Rated row above consists of collateral posted to 17 counterparties, mainly gas producers.

Fuel Supply and Transportation

Our fuel requirements consist primarily of nuclear fuel and various forms of fossil fuel including oil, natural gas and coal (including lignite). We obtain our oil, natural gas and coal from multiple sources. Although fossil fuels are generally available for purchase, localized shortages, transportation availability and supplier financial stability issues can and do occur. The prices of oil, natural gas and coal are subject to macro-and micro-economic forces that can change dramatically in both the short-term and the long-term. We are largely hedged for our domestic coal consumption over the next few years.

We arrange for the purchase, transportation and delivery of coal for our coal plants via a range of coal purchase agreements, rail and barge transportation agreements and rail car lease arrangements. Coal consumption in 2006 for NRG is expected to be approximately 36 million tons, which would rank us as one of

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the top five coal purchasers in the United States. In addition, approximately 92% of our coal-fired generation benefits from multiple sourcing and transportation alternatives. The Company has approximately 6,100 privately leased or owned rail cars in its transportation fleet. In addition, we intend to enter into contracts for delivery of approximately 2,700 additional rail cars within the next two years of which approximately 2,200 will replace existing rail cars. NRG has entered into rail transportation agreements that provide for substantially all of its rail transportation requirements through 2009.

STP satisfies its fuel supply requirements by acquiring uranium concentrates and contracting for conversion of the uranium concentrates into uranium hexafluoride, for enrichment of uranium hexafluoride and for fabrication of nuclear fuel assemblies. Through our subsidiary Texas Genco, we are party to a number of contracts covering a portion of the fuel requirements of STP for uranium, conversion and enrichment services and fuel fabrication. The table below summarizes the nuclear fuel situation at STP through the major processes:

	Process	Supplier(s)	Procurement Status
Step 1	Yellow cake U(3)O(8). Conversion to uranium hexafluoride (UF(6))	Contracts with Cameco (Canada) and Cogema/Arriba (France) combine these steps.	100% covered through mid-2011 and then 25% covered through 2021.
Step 2	Enrichment of U235 content	Urenco (Germany), Cogema/ Arriba (France), Louisiana Enrichment Services, or LES [(1)] (joint venture between Westinghouse & Urenco).	Urenco and Cogema contracts cover through mid-2008. Contract with Urenco/LES through 2027/2028.
Step 3	Fabrication of fuel rods	Westinghouse.	Contract covers life of operating license.

(1) Enrichment by LES assumes successful completion of LES licensing and construction of facility in New Mexico.

Financial Information About Segments and Geographic Areas

For financial information on NRG s operations on a geographical and on a segment basis, see Item 15 Note 21 to the Consolidated Financial Statements.

Dispositions of Non-Strategic Assets

We continued to market our interest in our remaining non-core assets during 2005. Since 2003, we sold or made arrangements to sell a number of consolidated businesses and equity investments in an effort to reduce our debt, improve liquidity and rationalize our investments. Dispositions completed during 2005 are summarized in the following chart:

Asset (Location)	Type	Segment	Closing Date	Proceeds	Gain/(Loss) on Disposition	Debt Reduction
					(In millions)	
Enfield, England	Equity investment	Other International	4/1/2005	$ 65	$ 12	$
Kendall, IL	Equity investment	Other North America	8/8/2005	5	4	
Northbrook New York, NY and Northbrook	Discontinued operation	Other North America	8/11/2005	36	12	44

Energy (Multi-state)						
Bourbonnais, IL	Land sale	Other North America	8/31/2005	2		
Kaufman, TX	Land sale	Other North America	12/22/2005	5	4	
Total				$ 113	$ 32	$ 44

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Reorganization

We were formed in 1992 as the non-utility subsidiary of Northern States Power Company, or NSP, which was itself merged into New Century Energies, Inc. to form Xcel Energy, Inc., or Xcel Energy, in 2000. In 2002, a number of factors including the overall downturn in the power generation industry, triggered a series of credit rating downgrades which, in turn, precipitated a severe liquidity crisis at the Company. From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code. All NRG entities have emerged from chapter 11 as of December 31, 2005. As part of our reorganization, Xcel Energy relinquished its ownership interest in us, and we became an independent public company. We no longer have any material affiliation or relationship with Xcel Energy.

Fresh Start Reporting

As a result of our emergence from bankruptcy, we adopted Fresh Start Reporting, or Fresh Start. Under Fresh Start, our confirmed enterprise value was allocated to our assets and liabilities based on their respective fair values. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operation Reorganization and Emergence from Bankruptcy for additional information. 2004 was our first complete year following the adoption of Fresh Start.

Significant Customers

Reorganized NRG (excluding Texas Genco)

For the year ended December 31, 2005 we derived approximately 50.2% of total revenues for majority owned operations from two customers: NYISO accounted for 35.6% and ISO-NE accounted for 14.6%. We account for the revenues attributable to these customers as part of our Northeast segment.

For the year ended December 31, 2004, we derived approximately 37.8% of our total revenues from majority-owned operations from two customers. NYISO accounted for 28.6% and ISO New England accounted for 9.2%. We account for these revenues attributable to NYISO and ISO New England as part of our Northeast segment.

For the period December 6, 2003 through December 31, 2003, we derived approximately 39.4% of our total revenues from majority-owned operations from two customers: NYISO accounted for 26.8% and ISO New England accounted for 12.6%. Revenues from NYISO and ISO New England are included in our Northeast segment.

Predecessor Company

For the period from January 1, 2003 through December 5, 2003, sales to one customer, NYISO, accounted for 33.4% of our total revenues from majority-owned operations.

Seasonality and Price Volatility

Annual and quarterly operating results can be significantly affected by weather and energy commodity price volatility. Significant other events, such as the demand for natural gas, interruptions in fuel supply infrastructure and relative levels of hydroelectric capacity can increase seasonal fuel and power price volatility. We derive a majority of our annual revenues in the months of May through September, when demand for electricity is the highest in our North American markets. Further, power price volatility is generally higher in the summer months due to the effect of temperature variations. Our second most important season is winter when volatility and price spikes in underlying fuel prices have tended to drive seasonal electricity prices. Issues related to seasonality and price volatility are fairly uniform across our business segments.

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Sources and Availability of Raw Materials

Our raw material requirements primarily include various forms of fossil fuel, including oil, natural gas and coal. We obtain our oil, natural gas and coal from multiple suppliers and transportation sources and availability is generally not an issue, although localized shortages, transportation availability and supplier financial stability issues can and do occur. The prices of oil, natural gas and coal are subject to macro- and micro-economic forces that can change dramatically in both the short-term and the long-term. For example, the price of natural gas was particularly volatile in late 2005 due to infrastructure damage caused by Hurricanes Katrina and Rita. Additionally, throughout 2005, oil prices were extremely volatile due to hurricane damage, geo-political uncertainty in the Middle East and increased global oil demand. Issues related to the sources and availability of raw materials are fairly uniform across our business segments.

Plant Operations

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

The functional areas included in this organization include safety and security, engineering, project management, construction services, and purchasing. These services also include overall facilities management, operations strategic planning and the development and dissemination of consistent policies and practices relating to plant operations.

Environmental Controls

Between 2002 and 2007, NRG has made, and will continue to make, investments that we believe will total approximately $125 million in its coal-fired plants in the Northeast region of the United States so that they can burn low sulfur coal from the Powder River Basin in Wyoming and Montana. These improvements have not only led to significant reductions in sulfur dioxide emissions, but have also improved the operational flexibility and financial performance of these plants. During the same period, NRG expects to invest approximately $32 million in its coal plants in the South Central region for NO_x burners and over fired air, which have led to reductions in NO_x. A significant portion of this investment may be recovered from NRG s cooperative customers. Texas Genco and its predecessors invested over $700 million in NO_x reduction initiatives since 1999 to ensure both regulatory compliance and continued performance, and we estimate we will invest approximately $70 million in additional capital expenditures in these assets to meet pollution control requirements from 2006 to 2014.

The following table summarizes the key existing and current forecasted plans as to environmental controls on our coal-fired units. Also see our discussion on Environmental Matters further within this Business Section:

	SO_2		NO_x		Hg		Particulate	
its	**Control Equipment**	**Install Date**	**Control Equipment**	**Install Date**	**Control Equipment**	**Install Date**	**Control Equipment**	**Instal Date**
ntley 67	Wet FGD[1]	2013	SNCR	2010	FF-ACI[2]	2011	ESP	19
ntley 68	Wet FGD[1]	2013	SNCR	2011	FF-ACI[2]	2009	ESP	19
nkirk 1	None		SNCR	2010	FF-ACI[2]	2010	ESP	19
nkirk 2	None		SNCR	2011	FF-ACI[2]	2011	ESP	19
nkirk 3	None		SNCR	2010	FF-ACI[2]	2011	ESP	19
nkirk 4	None		SNCR	2011	FF-ACI[2]	2010	ESP	19
lian ver 1	In-Duct Scrubber	2012	SNCR & LNB [3]	2008	Co-Benefit of Scrubbers	2012	ESP (IR1-3)	19
lian ver 2	In-Duct Scrubber	2013	SNCR & LNB [3]	2008	Co-Benefit of Scrubbers	2013	ESP (IR1-3)	19
lian ver 3	In-Duct Scrubber	2012	LNB[3] & SNCR upgrade	2008	Co-Benefit of Scrubbers	2012	ESP (IR1-3)	19
lian ver 4	Dry Scrubber	2011	LNB[3] & SNCR upgrade	2008	Co-Benefit of Scrubbers	2011	ESP (IR1-3)	19
g jun II 1	Dry Scrubber	2011	None		ACI[2]	2012	ESP	19
g jun II 2	Dry Scrubber	2010	SCR[4]	2010	ACI[2]	2011	ESP	19
g jun II 3	Dry Scrubber	2013	SCR[4]	2013	ACI[2]	2014	ESP	19
mestone	FGD	1986-87	LNB/OFA[3]	2000-01	Co-Benefit of Scrubbers		ESP	1986-
A Parish ,7	None	NA	SCR & LNB/OFA [3]	2000-04	None		FF	19
A Parish	FGD	1982	SCR & LNB/OFA [3]	2000-04	Co-Benefit of Scrubber		FF	19

(1) FGD stands for Flue Gas Desulfurization

(2) FF-ACI stands for Fabric Filter with Activated Carbon Injection

(3) LNB/ OFA stands for Low NO_x Burner with Over Fire Air

(4) SCR stands for Selective Catalytic Reduction

Performance Improvement and Cost and Process Control Initiatives

In May 2005, NRG announced FORNRG, a comprehensive cost and margin improvement program, consisting of a large number of asset, portfolio and headquarters-specific targeted initiatives. This effort has been branded as FORNRG, or Focus on ROIC@NRG. Projects are focused on improving plant performance, reducing purchasing and other costs and streamlining processes. A large number of initiatives are currently underway in plant operations including forced outage reductions and heat rate improvements at NRG s major base load facilities. Additional initiatives are underway at our regional and headquarter offices as well. The ultimate objective is to produce $100 million of recurring benefits by 2008.

There have been a number of parallel improvement programs underway at Texas Genco, which have focused on streamlining processes, right sizing the organization and running efficient operations. As part of the integration of Texas Genco into NRG, we are comparing best practices and results between NRG and Texas Genco, and we are combining purchasing programs and incorporating Texas Genco processes under the *FOR*NRG program.

Regional Business Descriptions

The combined company is organized into business units as described below, with each of our core regions operating as a separate unit.

TEXAS (ERCOT)

NRG s largest business unit is located in the Texas (ERCOT) region of the United States and is comprised of investments in generation facilities located in the physical control areas of the ERCOT-ISO. These assets were acquired on February 2, 2006 as part of the Texas Genco Acquisition.

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Operating Strategy

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

It is our strategy to sell forward up to 80% of our solid-fuel baseload capacity in ERCOT under long-term contracts. Accordingly, our primary focus will be to keep these solid-fuel baseload units running efficiently. The generation performance by fuel type for the recent three-year period is as shown below:

	Net Generation (MWh)		
	2005	2004	2003
	(In thousands)		
Coal	31,299	31,222	29,754
Gas	6,806	7,701	10,701
Nuclear	6,412	6,580	4,843
Total	44,517	45,503	45,298

On the gas-fired asset side, we will continue a dual path of contracting forward a significant portion of gas-fired capacity one to two years out while holding a portion for back-up in case there is an operational issue with one of the baseload units. For the gas-fired capacity sold forward, we offer a range of products including virtual units where the customer has the right to dispatch capacity as the customer needs in order to meet their physical load requirements. For the gas-fired capacity that we will continue to sell commercially into the market, we will focus on making this capacity available to the market whenever it is economic to run.

Texas Genco s growth efforts to date have been focused on adding incremental capacity to existing units such as the 99 MW uprate at Limestone 2 in the spring of 2006. We will continue this effort with exploration of some additional potential opportunities at W. A. Parish as well as some scheduled uprates at STP. We have also launched a broader brownfield development initiative where we will evaluate opportunities to take advantage of our current power plant sites and other land we own as well as our deep market, regulatory, and environmental knowledge to consider the development of new solid fuel baseload units.

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Facilities

The following table describes Texas Genco s electric power generation plants and generation capacity as of December 31, 2005:

Generation Sites	Location	% Owned	Net Generation Capacity (MW)[1]	Primary Fuel Type[2]
Solid Fuel Baseload Units:				
W. A. Parish[3]	Thompsons, TX	100%	2,463	Low Sulfur Coal
Limestone	Jewett, TX	100%	1,614	Lignite/Low Sulfur Coal
South Texas Project[4]	Bay City, TX	44%	1,101	Nuclear
Total Solid Fuel Baseload			5,178	
Operating Natural Gas-Fired Units:				
Cedar Bayou	Chambers County, TX	100%	1,498	Natural Gas
T. H. Wharton	Houston, TX	100%	1,025	Natural Gas
W. A. Parish (Natural gas)[3]	Thompsons, TX	100%	1,191	Natural Gas
S. R. Bertron	Deer Park, TX	100%	844	Natural Gas
Greens Bayou	Houston, TX	100%	760	Natural Gas
San Jacinto	LaPorte, TX	100%	162	Natural Gas
Total Operating Natural Gas-Fired			5,480	
Total Texas (ERCOT) Region			10,658	

(1) Actual capacity can vary depending on factors including weather conditions, operational conditions and other factors. ERCOT requires periodic demonstration of capability, and the capacity may vary individually and in the aggregate from time to time. Excludes 3,378 MW of inactive capacity available for redevelopment of which 174 MW of available capacity was sold on November 14, 2005. An additional 461 MW was moved to inactive status as of December 31, 2005.

(2) Low sulfur coal is coal mined from the Powder River Basin, a coal-producing area in northeastern Wyoming and southeastern Montana, which coal has low sulfur content relative to most coal from the eastern United States.

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

(4) Generation capacity figure consists of our 44.0% undivided interest in the two units of STP.

W.A. Parish. The W. A. Parish plant is one of the largest fossil-fired plants in the United States based on total MWs of generation capacity. The plant is located in the Houston ERCOT zone and was recognized by Platts Power Magazine as one of the top power plants in the United States for 2004. This plant s power generation units include four coal-fired steam generation units with an aggregate generation capacity of 2,463 MW as of December 31, 2005. Two of these units are 649 MW steam units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 555 MW and 610 MW steam units that were placed in commercial service in June 1980 and December 1982, respectively. All four units are serviced by two competing railroads that diversify Texas Genco s coal transportation options at competitive prices. Texas Genco invested approximately $430 million in nitrogen oxide, or NO_x, control systems from 1999 to 2004. Each of the four coal-fired units has low- NO_x burners and selective catalytic reduction, or SCR, installed to reduce NO_x emissions. In addition, W. A. Parish Unit 8 has a scrubber installed to reduce sulfur dioxide, or SO_2, emissions. Plant efficiency projects to be completed by year end 2007 are expected to uprate the net generation capacity of W.A. Parish by 31 MW.

Limestone. The 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 1,614 MW as of December 31, 2005. The first unit is an 836 MW steam unit that was placed in commercial service in December 1985. The second unit is a 778 MW steam unit that was placed in commercial service in December 1986. Limestone primarily burns lignite from an on-site mine, but also burns low sulfur coal and petroleum coke. This serves to lower average fuel costs by eliminating fuel transportation costs, which can represent up to two-thirds of delivered fuel costs for plants of this type. We own the mining equipment and facilities and a portion of the lignite reserves located at the mine. Mining operations are conducted by Texas Westmoreland Coal Co., a single purpose, wholly-owned subsidiary of Westmoreland Coal Company and the owner of a substantial portion of the remaining lignite reserves. Both units have installed low- NO_x burners to reduce NO_x emissions and scrubbers to reduce SO_2 emissions. In the second quarter of 2006 we plan to replace the high pressure and intermediate pressure turbines at Limestone Unit 2, rewinding the generator and replacing the main generator step-up transformer. This work is expected to cost approximately $33 million and to improve generation capacity by 99 MW.

South Texas Project Electric Generating Station. STP is one of the newest and largest nuclear-powered generation plants in the United States based on total megawatts of generation capacity. This plant is located approximately 90 miles south of downtown Houston, near Bay City, Texas and consists of two generation units each representing approximately 1,250 MW of generation capacity. Plant efficiency projects to be completed by 2007 are expected to uprate the net generation capacity of STP by 73 MW (32 MW net to NRG). STP s two generation units commenced operations in August 1988 and June 1989, respectively. For the year ended December 31, 2004, STP had a forced outage rate of 0.4% and a 97% capacity factor.

STP is currently owned as a tenancy in common among NRG and two other co-owners. NRG owns a 44.0% (1,101 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. In the event any owner desires to sell all or part of its ownership interest in STP, such sale is subject to a right of first refusal in favor of the other owners. Except for certain plant shutdown and decommissioning costs and NRC licensing liabilities, NRG is severally liable, but not jointly liable, for the expenses and liabilities of STP. The original co-owners of STP organized South Texas Project Nuclear Operating Company, or STPNOC, to operate and maintain STP. STPNOC is managed by a board of directors composed of one director appointed by each of the three co-owners, along with the chief executive officer of STPNOC. STPNOC is the NRC-licensed operator of STP. No single owner controls STPNOC and all decisions must be approved by two or more owners who collectively control more than 60% of the interests. Due to the fact that NRG owns 44% of STP, NRG effectively holds a veto right.

In connection with the acquisition by Texas Genco of 13.2% of STP from AEP, Texas Genco, LP agreed with AEP that, for a period of ten years from May 19, 2005, Texas Genco, LP would maintain a minimum partners equity, determined in accordance with GAAP, of $300 million. This obligation remains in effect as an obligation of NRG.

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

Market Framework

The ERCOT market is one of the nation s largest and fastest growing power markets. It represents approximately 85% of the demand for power in Texas and covers the whole state, with the exception of the far west (El Paso), a large part of the Texas Panhandle and two small areas in the eastern part of the state. From 1994 through 2004, peak hourly demand in the ERCOT market grew at a compound annual rate of 3.0%, compared to a compound annual rate of growth of 2.1% in the United States for the same period. For 2004, hourly demand ranged from a low of 20,276 MW to a high of 58,506 MW. ERCOT has limited interconnections currently limited to 856 MW of generation capacity to other markets in the United States, and wholesale transactions within ERCOT are not subject to regulation by FERC. Any wholesale producer of power that qualifies as a power generation company under the Texas electric restructuring law and that can access the ERCOT electric power grid is allowed to sell power in the ERCOT market at unregulated rates.

The ERCOT market has experienced significant construction of new generation plants in recent years, with over 20,000 MW of mostly natural gas-fired combined cycle generation capacity added to the market

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since 2000. As of December 31, 2005, aggregate net generation capacity of approximately 81,000 MW existed in the ERCOT market, of which 73% was natural gas-fired. Approximately 20,000 MW, or 25%, was lower marginal cost generation capacity such as coal, lignite and nuclear plants. NRG s coal and nuclear fuel baseload plants represent approximately 5,178 MW, or 26%, of the total solid fuel baseload net generation capacity in the ERCOT market. ERCOT has established a target equilibrium reserve margin level of approximately 12.5%; the reserve margin as of the latest known information on December 31, 2005 was 16.9%. Construction of new generation plants has been minimal since 2004, and we expect that reserve margins will decrease as demand gradually grows and surpasses recently added supply.

In the ERCOT market, buyers and sellers enter into bilateral wholesale capacity, power and ancillary services contracts or may participate in the centralized ancillary services market, including balancing energy, which ERCOT administers. In the ERCOT market, a 2004 report by Henwood found that natural gas-fired plants have set the market price of wholesale power more than 90% of the time. As a result, NRG s lower marginal cost solid-fuel baseload plants are expected to generate power nearly 100% of the time they are available.

The ERCOT market is divided into five regions or congestion zones (Northeast, North, Houston, South and West), which reflect transmission constraints that limit the amount of power that can flow across zones. NRG s W. A. Parish plant and all its natural gas-fired plants are located in the Houston zone, NRG s Limestone plant is located in the North zone and STP is located in the South zone.

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

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

The PUCT has adopted a rule directing the ERCOT-ISO to develop and implement a wholesale market design that, among other things, includes a day ahead energy market and replaces the existing zonal wholesale market design with a nodal market design that is based on locational marginal prices for power. See Regulatory Developments Regional Businesses Market Developments Texas (ERCOT) Region. One of the stated purposes of the proposed market restructuring is to reduce local (intra-zonal) transmission congestion costs. The market redesign project is expected to take effect in 2009. We expect that implementation of any new market design will require modifications to our procedures and systems. Although we do not expect the combined company s competitive position in the ERCOT market will be materially adversely affected by the proposed market restructuring, we do not know for certain how the planned market restructuring will affect our revenues, and some of the combined company s plants in ERCOT may experience adverse pricing effects due to their location on the transmission grid.

PUCT Mandated Auctions

PUCT regulation required firm entitlements to 15% of NRG s operating installed generation capacity to be sold at auction through December 31, 2006, at opening bid prices well below NRG s cost for 2006. On December 7, 2005, Texas Genco filed an application with the PUCT requesting the PUCT to determine that we were no longer required to conduct mandated auctions because 40% or more of the electric power consumed by the residential and small commercial customers within the CenterPoint Energy Houston Electric, LLC certificated service area before the onset of customer choice is now provided by nonaffiliated retail electric providers. On February 6, 2006, the Staff of the PUCT reported that ERCOT had performed the analysis and calculations necessary to demonstrate that we have satisfied the 40% threshold. The Staff recommended that the petition be granted and that we be released from any further capacity auction requirements. The administrative law judge issued her proposal for decision, and a decision by the PUCT is expected in March.

NORTHEAST REGION

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

Operating Strategy

The Northeast region strategy is focused on optimizing the value of our broad and varied generation portfolio in three interconnected and actively traded competitive markets: the NYISO, the ISO-NE and the PJM. In our Northeast markets, load serving entities generally lack their own generation capacity, much of the generation base is aging, and the current ownership of the generation is highly disaggregated. Thus, commodity prices are more volatile on an as-delivered basis than in other regions due to the distances and occasional physical constraints impacting delivery of fuels into the region. In this environment, we seek both to enhance our 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 (MWh)		
	2005	**2004**	**2003**
		(In thousands)	
Coal	10,369	10,664	9,783
Oil	3,158	1,381	1,471
Gas	1,724	1,160	1,172
Total	15,251	13,205	12,426

Several of our Connecticut assets are located in transmission-constrained load pockets and have been designated as required to be available to ISO-NE to ensure reliability. These assets are subject to reliability must-run, or RMR, agreements, which are contracts under which we agree to maintain our facilities to be available to run when needed, and are paid for providing these capability services based on our costs. We are focused on capturing the locational value of our plants that are located in or near load centers and inside chronic transmission constraints, in order to improve the economic rationale for repowering of those sites. We do this principally through the advocacy of capacity market reforms, e.g., locational installed capacity markets that generate adequate returns for wholesale power generators.

We continue to evaluate opportunities to redevelop our existing sites as well as opportunities for acquisitions in the Northeast region. The redevelopment opportunities for our existing sites include expanding sites with high efficiency, intermediate and peaking units, converting coal or oil sites to cleaner technologies, redeveloping existing sites with projects using IGCC technology, as well as reconfiguring the existing sites to burn renewable fuel sources. Redevelopment opportunities have been identified for each site in the Northeast and we have established priorities based on expected financial returns and probability of success. To facilitate redevelopment opportunities, we are pursuing contractual arrangements to support significant redevelopment capital expenditures via direct negotiations with relevant agencies and potential power purchasers as well as through request for proposal processes. We also continue to pursue contractual arrangements to support the

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construction costs of potential new facilities and acquisition opportunities through public auction processes as well as by initiating discussions with various parties on potential opportunities.

Facilities

As of December 31, 2005, NRG s facilities in the Northeast region consisted of approximately 7,099 MW of generation capacity, including assets located in transmission constrained areas, such as in-city New York City (1,394 MW) and southwest Connecticut (538 MW). The Northeast region power generation assets are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity (MW)*	Primary Fuel Type
Oswego	Oswego, NY	100.0%	1,634	Oil
Arthur Kill	Staten Island, NY	100.0%	841	Natural Gas
Middletown	Middletown, CT	100.0%	770	Oil
Indian River	Millsboro, DE	100.0%	737	Coal
Astoria Gas Turbines	Queens, NY	100.0%	553	Natural Gas
Dunkirk	Dunkirk, NY	100.0%	522	Coal
Huntley	Tonawanda, NY	100.0%	552	Coal
Montville	Uncasville, CT	100.0%	497	Oil
Norwalk Harbor	So. Norwalk, CT	100.0%	342	Oil
Devon	Milford, CT	100.0%	124	Natural Gas
Vienna	Vienna, MD	100.0%	170	Oil
Somerset Power	Somerset, MA	100.0%	127	Coal
Connecticut Remote Turbines	Various locations in CT	100.0%	104	Oil
Conemaugh	New Florence, PA	3.7%	64	Coal
Keystone	Shelocta, PA	3.7%	63	Coal
Total Northeast Region			**7,099**	

* Excludes 382 MW of inactive capacity.

The following are descriptions of our 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 841 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 335 MW and was installed in 1959. Unit 30 produces an aggregate generation capacity of 491 MW and was installed in 1969, and both Units were converted from steam engines in the early 1990s. We may need to upgrade the plant in the future to comply with environmental regulations. If upgrades are needed it could cost several million dollars.

Astoria Gas Turbines. Adjacent to LaGuardia airport in Queens, New York, Astoria provides power to the local New York City load pockets. The facility has an aggregate generation capacity of 553 MW from 19 operational combustion turbine engines. The turbine engines are peak gas-fired and/or oil-fired installed in the early 1970s. The engines are classified into three classes, which are then grouped into ten Astoria Gas Turbine units. These units consist of Buildings 2, 3 and 4, which have a total net generation capacity of 431 MW and will be retired in 2022. Units 5, 7 and 8, which are Class 2 turbine engines, have a net generation capacity totaling approximately 42 MW; and will be retired in 2015. Units 10, 11, 12 and 13, which are Class 3 turbine engines have a total net generation capacity of 80 MW, will be retired in 2015 as well.

Dunkirk. NRG s Dunkirk plant is a coal-fired plant located on Lake Erie in Dunkirk, New York. This plant produces an aggregate generation capacity of 522 MW from four baseload units. Units 1 and 2 produce up to 81 MW each and were put in service in 1950. Units 3 and 4 produce approximately 180 MW each and were put in service in 1959 and 1960, respectively. The plant is currently implementing changes to switch from eastern bituminous coal to low sulfur PRB coal in order to comply with various federal and state emissions standards, as well as the NYSDEC settlement referred to in the following paragraph. The conversion will be completed for all units by Spring 2006.

Huntley. NRG s Huntley plant is a coal-fired plant consisting of six units and is located in Tonawanda, New York, approximately three miles north of Buffalo. The plant has a generation capacity of 552 MW from two intermediate load units (Units 65 and 66) and two baseload units (Units 67 and 68). Units 67 and 68 generate a net capacity of approximately 190 MW each and were put in service in 1957 and 1958, respectively. Units 65 and 66 generate a net capacity of 86 MW each and were put in service between 1942 and 1954. Units 63 and 64 are currently inactive. At the end of 2005, NRG gave notice to the New York Public Service Commission, or NYPSC, of its intent to retire Units 63 and 64 in early 2006, subject to NYPSC approval. As part of a settlement reached with the New York Department of Environmental Conservation, or NYSDEC, in January 2005, NRG will reduce NOx and SOx emissions from its Huntley and Dunkirk plants through 2013 in the aggregate by over 80% and 86%, respectively. A portion of these reductions has been achieved through the switch to PRB coal and related projects completed at the plant that have already been expended or committed to.

Market Framework

Although each of the three northeast ISOs and their respective energy markets are functionally, administratively and operationally independent, they all follow, to a certain extent, similar market designs. Each ISO dispatches power plants to meet system energy and reliability needs, and settles physical power deliveries at locational marginal prices, or LMPs, which reflect the value of energy at a specific location at the specific time it is delivered. This value is determined by an ISO-administered auction process, which evaluates and selects the least costly supplier offers or bids to create a reliable and least-cost dispatch. The ISO-sponsored LMP energy markets consist of two separate and characteristically distinct settlement time frames. The first is a security-constrained, financially firm, day-ahead unit commitment market. The second is a security-constrained, financially settled, real-time dispatch and balancing market. Prices paid in these LMP energy markets, however, are affected by, among other things, market mitigation measures which can result in lower prices associated with certain generating units that are mitigated because they are deemed to have locational market power, and by $1000/ MWh energy market price caps that are in place in all three northeast ISOs.

In addition to energy delivery, the ISOs manage secondary markets for installed capacity, ancillary services and financial transmission rights. All of the three northeastern ISOs have realized, however, that they are not capable of supporting needed investment in new generation without well designed capacity and ancillary service markets. NYISO s capacity market was the first to receive approval of its proposed demand curve and locational capacity reforms (which are intended to better reflect locational values of capacity resources). ISO-NE and PJM have both proposed their respective versions of reformed capacity markets, namely, a locational installed capacity market, or LICAP in ISO-NE, and a reliability pricing model, or RPM proposal in PJM. These proposals are currently pending before FERC. Also see further discussion in Item 15 Note 26 Regulatory Matters.

SOUTH CENTRAL REGION

As of December 31, 2005, NRG owned approximately 2,395 MW of generating capacity in the South Central region of the United States. The region lacks an ISO and, therefore, remains a bilateral market, making it less transparent than a region with an ISO-administered energy market using large scale economic dispatch (such as the Northeast markets discussed above). Our plants in the South Central region operate as their own control area, the South Central control area. As a result, the South Central control area is capable of providing control area services, in addition to wholesale power, that enables NRG to provide full requirement services to load serving utilities, thus making the South Central control area a competitive alternative to the integrated utilities operating in the region.

Operating Strategy

Our South Central region seeks to capitalize on two factors: our position as a significant coal-fired generator in a market which is highly dependent on natural gas for power generation purposes; and our long-term contractual and historical service relationship with 11 rural cooperatives around Louisiana. We are working with our cooperative customers to improve contract administration, to expand their and our customer base on terms advantageous to all parties and, in some cases, to modify the terms of our contracts with respect to our current or new customers.

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

	Net Generation (MWh)		
	2005	2004	2003
		(In thousands)	
Coal	10,103	10,469	10,318
Gas	14	2	27
Total	10,117	10,471	10,345

As part of our strategy, we are examining all of our sites in the South Central region for possible brownfield development. In particular, we continue the development of the new 675 MW Big Cajun II Unit 4 super critical coal-fired generating unit. On August 22, 2005, NRG received the Title V Air Permit from the Louisiana Department of Environmental Quality. On October 14, 2005, Washington Group International was selected as the owner s engineer. We continue to aggressively pursue equity partners and off-takers for the output of the unit. We continue to look for opportunities to acquire assets that will enhance our portfolio and long-term strategic goals.

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 we refer to as Big Cajun II, and also includes the Sterlington, Bayou Cove and Big Cajun peaking facilities. NRG s power generation assets in the South Central region as of December 31, 2005 are summarized in the table below:

Plant	Location	% Owned	Net Generating Capacity (MW)	Primary Fuel Type
Big Cajun II[1]	New Roads, LA	86.0%	1,489	Coal
Bayou Cove	Jennings, LA	100.0%	300	Natural Gas
Big Cajun I (Peakers) Units 3 & 4	New Roads, LA	100.0%	210	Natural Gas
Big Cajun I Units 1 & 2	New Roads, LA	100.0%	220	Natural Gas/Oil
Sterlington	Sterlington, LA	100.0%	176	Natural Gas
Total South Central			**2,395**	

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

Big Cajun II. Our most significant revenue generating plant in the South Central region is the Big Cajun II facility. Big Cajun II plant is a coal-fired, sub-critical heat baseload plant located along the banks of the Mississippi River, upstream from Baton Rouge. This plant includes three coal-fired generation units (Units 1, 2 and 3) with an aggregate generation capacity of 1,730 MW as of December 31, 2005, and generation capacity per unit of 580 MW, 575 MW and 575 MW, respectively. The plant uses coal supplied by the Powder River Basin and was commissioned between 1981 and 1983. NRG owns 100% of Units 1 and 2 and 58% of Unit 3 for an aggregate owned capacity of 1,489 MW (86.0%) of the plant. All three units have

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been upgraded with low NOx burners and over fire air. The Unit 1 generator has recently been rewound and was optimized with a modern turbine/exciter control system. Units 2 and 3 are planned for generator rewinds, turbine/exciter control replacements and additional neural net systems in future years. These efficiency improvements are expected to cost approximately $30 million.

Market Framework

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

As of December 31, 2005, NRG had long-term all-requirements contracts with 11 Louisiana distribution cooperatives. The agreements are standardized into three types, Forms A, B and C and have the terms, contract loads and customers as shown in the table below:

	Expiration	Estimated Contract Load	Customers
Form A	March 2025	42%	6
Form B	March 2025	3%	1
Form C	March 2009-2014	42%	4

NRG also has long-term contracts with the Municipal Agency of Mississippi, South Mississippi Electric Power Association, and Southwestern Electric Power Company, which collectively comprise an additional 13% of contract load.

At peak demand periods, NRG s Big Cajun II assets are insufficient to serve the requirements of the customers under these contracts, and at such times, NRG typically purchases power from other power producers in the region, frequently at higher prices than can be recovered under our contracts. As the loads of our customers grow, we can expect this imbalance to worsen, unless we are successful in renegotiating the terms of our long-term contracts.

We are currently in negotiations with these customers to achieve contractual amendments that limit incremental load growth at contract rates for large industrial and municipal loads. To date, we have been successful in achieving such amendments with two of the eleven cooperative contracts.

As a result of Hurricanes Katrina and Rita in August and September 2005, NRG recognized a loss of approximately $1.3 million for damaged assets. Four of the South Central region s 11 cooperative customers suffered extensive losses to their distribution systems, and the region suffered a drop in contract sales during the ensuing power outages. By year-end, loads have largely returned to normal for three of the four hard-hit cooperatives, while the fourth cooperative continues to face challenges in rebuilding. The load loss and the transmission constraints had offsetting impacts on the South Central region s margins resulting in gross margins that were $4 million below expectations. In addition, NRG created a reserve for a receivable from Entergy New Orleans of $1.9 million because of its hurricane-related bankruptcy.

WESTERN REGION

As of December 31, 2005, NRG owned approximately 1,044 MW of generating capacity in the Western region of the United States (California), of which approximately 904 MW is through a 50% interest in WCP Holdings. On December 27, 2005, NRG entered into a purchase and sale agreement to acquire Dynegy s 50% ownership interest in West Coast Power to become the sole owner of power plants totaling approximately

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1,800 MW of generation capacity in the Western region. The transaction, which is subject to regulatory approval, is expected to close in the first quarter of 2006.

Operating Strategy

Our Western region strategy is focused on maximizing the cash flow and value associated with our generating plants while protecting and potentially realizing the commercial value of the underlying real estate in case our following initiatives do not generate value. There are three principal components to this strategy. First, we are focused on influencing market reforms in California to provide an energy market environment where our capacity can be offered into centrally administered competitive auctions, such as we see in the Northeast, and also provide for the negotiation of bilateral transactions for both energy and capacity. Second, we are preparing our sites for the construction of new capacity to meet increasing local area requirements. At El Segundo, NRG has a California Energy Commission, or CEC, permit to construct a new combined cycle plant to replace the retired units at the site. At the Long Beach site, NRG has land available to construct new peaking capacity. NRG is developing plans for site remediation and preparation in anticipation of a new request for new capacity from load serving entities. Third, we are engaged in the identification of collaborative value enhancing projects with communities and businesses located near our plants. West Coast Power s plants are, for example, considered excellent candidates for the co-location of desalination plants. In case the said initiatives fail, we are taking active steps to assess the value of our property for non-power generation purposes. The real estate value from our plant locations is promising as two of West Coast Power s plants are situated at choice locations on the Pacific coast.

NRG s assets in the Western region include three additional power plants, Red Bluff and Chowchilla (94 MW total), located in northern California that have some locational value and one plant in Henderson, Nevada (Saguaro), that is contracted to Nevada Power and two steam hosts. NRG has entered into a resource adequacy agreement with PG&E Corporation, or PG&E, for the capacity of the Red Bluff and Chowchilla units that expires December 31, 2007. The Saguaro plant in Nevada is contracted to Nevada Power through 2022, one steam host (Pioneer) whose contract expires in 2007 (with a negotiated renewal) and a steam off taker (Ocean Spray), whose contract runs through 2015. The Saguaro plant had a long-term gas supply agreement that expired in July 2005 and the plant is now exposed to the monthly spot gas market. At present, Saguaro cannot pass higher natural gas costs through to its customers, and the plant is currently experiencing negative cash flows. Consequently, during 2005, we wrote down our equity investment in Saguaro by approximately $27 million. NRG is currently researching a number of alternatives for its investment in Saguaro.

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Facilities

NRG s power generation assets in the Western region as of December 31, 2005 are summarized in the table below:

Plant	Location	% Owned	Net Generation Capacity (MW)	Primary Fuel Type
WCP(1)				
Encina	Carlsbad, CA	50.0%	483	Natural Gas
El Segundo	El Segundo, CA	50.0%	335	Natural Gas
Cabrillo II	San Diego, CA	50.0%	86	Natural Gas
Total WCP			904	
Other Western Region Assets				
Saguaro	Henderson, NV	50.0%	46	Natural Gas
Chowchilla	Northern CA	100.0%	49	Natural Gas
Red Bluff	Northern CA	100.0%	45	Natural Gas
			140	
Total Western Region			**1,044**	

(1) On December 27, 2005, NRG entered into a purchase and sale agreement to acquire Dynegy s 50% ownership interest in WCP Holdings to become the sole owner of power plants totaling approximately 1,800 MW of generation capacity in the Western region. The transaction is expected to close in the first quarter of 2006.

NRG s assets in the Western region consist primarily of older, higher heat rate, gas-fired plants in southern California. These plants, while older and less efficient than newer combined cycle plants, possess locational advantages during peak hours when the newer, remotely located plants are unable to get through transmission congestion in southern California. As a result, the Cal ISO designated NRG s El Segundo, Encina and Cabrillo II plants as RMR qualifying units in 2005, and therefore those plants are entitled to certain fixed-cost payments from the Cal ISO for the right to dispatch those units during periods of locational constraints. Initially, transmission upgrades by Southern California Edison and San Diego Gas and Electric in 2005 caused the Cal ISO to drop the RMR designation for both El Segundo and the Encina Unit 4 for 2006. However, Cal ISO designated Encina Unit 4 as an RMR unit in a letter to Cabrillo Power I dated December 22, 2005, and a filing requesting FERC approval of the requisite changes to Cabrillo Power I s RMR agreement for 2006 was made on December 29, 2005. This change, if approved, will assure that Encina Units 4 and 5 will receive partial cost recovery under RMR and both units will be available in the market for 2006.

Market Framework

The majority of NRG s assets in the Western region are located within the control area of the Cal ISO. The Cal ISO operates a financially settled real time balancing market. There are currently no organized day ahead markets in the Western region and such forward markets in California currently operate similarly to those in the ERCOT market with all power sales and purchases consummated bilaterally between individual counterparties and scheduled for physical delivery with the Cal ISO. All plants are subject to the FERC must offer order, an order instituted during the energy crisis of 2000-2001 requiring any generator capable of operating and not subject to a bilateral agreement to make its capacity available to Cal ISO. The compensation paid by the Cal ISO for such service generally covers only variable costs. Additionally, California generators remain subject to a $250 per MWh price cap, another legacy of the energy crisis mentioned above. FERC approved an increase in the softcap from $250 per MWh to $400 per MWh, effective January 1, 2006. NRG is working with various industry groups and governmental authorities to put market reforms in place in California that will encourage new investment and enable generators to earn acceptable returns on new and existing investments.

WCP will continue to pursue repowering opportunities at the El Segundo, Encina and Long Beach plants where grid stability and in-load resource adequacy is needed. On December 23, 2004, the CEC approved NRG s application for a permit to repower the existing El Segundo site and replace retired units 1 and 2 with 630 MW of new combined cycle generation. On January 19, 2005, the CEC voted unanimously to reconsider its December 23, 2004 decision to certify the repowering project. The reconsideration hearing took place on February 2, 2005 and the permit was approved by unanimous vote of the CEC. The reconsideration extended the 30-day period in which parties may petition for rehearing or seek judicial review to March 4, 2005. A petition seeking review of the CEC final order was filed with the California Supreme Court on March 14, 2005. On August 31, 2005, the California Supreme Court refused to hear the case, making that date the effective date of the permit. The El Segundo permit has as a condition the payment of $5 million by the project to the Santa Monica Bay Restoration Fund with the first $1 million being due in equally quarterly installments beginning 30 days following the disposition of all appeals. The initial quarterly payment has been made. Should we elect to repower the Long Beach site, we will do it outside of the CEC permitting process. We do not believe the CEC can legally assert jurisdiction over a Long Beach repowering project as the total anticipated megawatts added will be less than the number of megawatts retired. The California Court of Appeals, in a case involving the Los Angeles Department of Water and Power, held that the CEC jurisdiction is only required where the total megawatts added exceed the existing megawatts of capacity by over 50 megawatts.

In California, the Cal ISO continues with its plan to move toward markets similar to PJM, NYISO and ISO-NE with its Market Redesign & Technology Upgrade, or MRTU formerly MD02. These changes, once implemented, will re-establish a day-ahead time market and allow for multiple settlements. We view this as a vast improvement to the existing structure. In general, the Cal ISO is continuing along a path of small incremental changes rather than significant market restructuring. Although numerous stakeholder meetings have been held, the final market design remains unknown at this time. The effect of the new MRTU changes on us cannot be determined at this time. In addition to that activity, the California Public Utility Commission, or CPUC, recently issued their Resource Adequacy Order, which we believe will ultimately create greater opportunities for merchant generators in California. However, the final order did delay the implementation of local capacity requirements and allowed a liberalized phase out of firm liquidated damages contracts, which may act as a disincentive for load serving entities to contract for our capacity over the next two years. Assembly Bill 1576 which will promote and codify the recovery of costs from repowered facilities thus making contracting from these sites more attractive to the in-state-utilities, was passed by the Senate on September 8, 2005, and signed by the Governor on September 29, 2005. This provides opportunities for the Western region, as WCP currently holds a permit for repowering up to 630 MW at the El Segundo facility and options for redevelopment at the Long Beach facility. Both facilities are positioned for possible long-term contracts as the market rules and structure fall into place in the near future.

The CEC recently issued their 2005 Energy Report Range of Need and Policy Recommendations To the California Public Utilities Commission, or CPUC. That study confirmed that the SCE franchise territory will require over 8,000 MW of new generation capacity by 2009; a dire prediction for a state with limited new resources coming on line and retirement of older facilities accelerating. There is some indication that the various regulatory agencies are responding to these warnings by moving to design a market that will provide the incentives to invest in new generation. The CPUC now requires that load-serving entities meet a 15-17% reserve margin by June 2006. This has prompted RFOs from load-serving entities, with the stated goal of engaging in bilateral contract negotiations with the merchant generators to secure their long-term capacity needs. Load-serving entities must demonstrate, by January 27, 2006 and by September 30 for each year thereafter that they have secured at least 90% of their capacity needs for the following year. The CPUC order requiring a demonstration of adequate capacity should present opportunities to enter into new bilateral agreements pursuant to competitive RFO processes. The Red Bluff and Chowchilla facilities have received capacity contracts for the period April 1, 2006 through December 31, 2007 from a major load serving entity.

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The capacity for El Segundo Units 3 and 4 has been secured under a tolling agreement with a major load serving entity for the period May 2006 through April 2008.

In September 2004, Governor Schwarzenegger vetoed AB2006, commonly referred to as the re-regulation initiative. A proposition (Proposition 80) that would amend legislation forever prohibiting customer choice in California was defeated in a November 2005 special election.

OTHER

Other North American Assets

As of December 31, 2005, NRG owned approximately 1,467 MW of generating capacity in other segments of the United States. NRG s other North American power generation assets are summarized in the table below:

Plant	Location	% Owned	Net Generating Capacity MW	Primary Fuel Type
Audrain*	Vandalia, MO	100.0%	577	Natural Gas
Rockford I (Peaker)	Rockford, IL	100.0%	310	Natural Gas
Rocky Road Partnership*	East Dundee, IL	50.0%	165	Natural Gas
Rockford II (Peaker)	Rockford, IL	100.0%	160	Natural Gas
Dover	Dover, DE	100.0%	104	Natural Gas/Coal
Power Smith Cogeneration	Oklahoma City, OK	6.25%	7	Natural Gas
Ilion Cogeneration*	New York	100.0%	58	Natural Gas
James River	Virginia	50.0%	55	Coal
Cadillac*	Cadillac, MI	50.0%	19	Wood
Paxton Creek	Harrisburg, PA	100.0%	12	Natural Gas
Other North American Assets			**1,467**	

* Certain of the above projects are in transition. The Audrain project is under contract for sale. Closing is expected in 2006. NRG is in advanced discussions regarding the sale of the Cadillac project. NRG is currently performing under an agreement whereby the Ilion project will be disconnected and terminated. On December 27, 2005, NRG entered into a purchase and sale agreement with Dynegy through which NRG will sell to Dynegy its 50% ownership interest in the jointly held entity that owns the Rocky Road power plant. The transaction is conditioned upon NRG s acquisition of Dynegy s 50% interest in WCP Holdings and is expected to close in the first quarter of 2006.

Australia and All Other Generation and Non-Generation Assets

As of December 31, 2005, NRG, through certain foreign subsidiaries, had investments in power generation projects located in Australia, Germany and Brazil with approximately 1,916 MW of total generating capacity. In addition, NRG owns interests in coal mines located in Australia and Germany.

NRG s international power generation assets as of December 31, 2005 are summarized in the table below:

Plant	Location	% Owned	Net Generating Capacity MW	Primary Fuel Type
Operating Assets				
Flinders	Australia	100.0%	700	Coal
Gladstone	Australia	37.5%	605	Coal
Schkopau	Germany	41.9%	400	Coal
MIBRAG(1)	Germany	50.0%	55	Coal
Itiquira	Brazil	99.2%	156	Hydro
Total International Assets			**1,916**	

(1) Primarily a coal mining facility. Approximately 90% of MIBRAG s revenues represent coal sales and 8% represent electricity sales. MIBRAG owns 110 MW of net exportable generation. Approximately two-thirds of that amount is sold to third parties and one-third is used to power mining and other MIBRAG operations. NRG equity in net exportable electricity is 55 MW.

Australia

Asset Management Strategy. Our strategy for maximizing our return on investment in our assets concentrates on effective contract management, operating the plant to ensure safe and efficient operations and management of the equity investment, including cash flow and finances. NRG is currently considering strategic alternatives with respect to Australia either to reposition its assets more effectively within the National Electricity Market or to monetize its investment. We will seek to determine the best option to optimize our investment by the end of the second quarter of 2006.

NRG Flinders Assets. NRG Flinders is a merchant generation business that derives revenue from bidding its generation output into the South Australian region of the National Electricity Market, or NEM, by trading the plant as a portfolio, selling derivative hedges that are not plant specific and supplying minor retail sales via contract. The bidding of the plant as a portfolio supports strategies for maximizing revenue of the entire portfolio both in terms of pool and derivative revenues and the most economic fuel use. A hedge book is maintained such that the short to medium term revenue is secured via hedge levels up to and in the order of 75-80% of the plant output. The current book is underpinned by a medium term hedge with a major South Australian retailer.

The Gladstone Assets. We are the operators of the Gladstone facility, however, the Gladstone assets are owned in an unincorporated joint venture with other investors and NRG does not have unilateral control over management of the assets. Gladstone Power Station is fully contracted via a power purchase agreement and a capacity purchase agreement with Boyne Smelter Limited and Enertrade through 2029. Enertrade is a state owned company that trades the excess power in the NEM.

Germany

Asset Management Strategy

Our German assets are owned in partnership with other investors and NRG does not have direct control over operations. Our strategy for maximization of return on investment therefore concentrates on the following: contract management, monitoring of our facility operators to ensure safe, profitable and sustainable operations; management of cash flow and finances; and growth of our businesses through investments in projects related to our current businesses.

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Thermal and Chilled Water Businesses

NRG Thermal s thermal and chilled water businesses have a steam and chilled water capacity of approximately 1,225 megawatt thermal equivalents, or MWt.

As of December 31, 2005, NRG Thermal owned heating and cooling systems that provide steam heating to approximately 555 customers and chilled water to 95 customers in five different cities in the United States. In addition, as of that date, NRG Thermal owned and operated three projects that serve industrial/government customers with high-pressure steam and hot water, an 88 MW combustion turbine peaking generation facility and an 16 MW coal-fired cogeneration facility in Dover, Delaware and a 12 MW gas-fired project in Harrisburg, Pennsylvania. Approximately 34% of Thermal s revenues are derived from its district heating and chilled water business in Minneapolis, Minnesota.

Both our NRG Energy Center Pittsburgh and our NRG Energy Center Harrisburg anticipate filing rate cases during 2006 seeking increased rates under their tariffs for steam services as well as chilled water for Pittsburgh.

Resource Recovery Facilities

NRG s Resource Recovery business owns and operates fuel processing projects. The alternative fuel currently processed is municipal solid waste, approximately 85% of which is processed into refuse derived fuel, or RDF. NRG s Resource Recovery business has municipal solid waste processing capacity of 3,000 tons per day. NRG s Resource Recovery business owns and operates NRG Processing Solutions, which includes 14 composting and processing sites in Minnesota, of which five sites are permitted to operate as municipal solid waste transfer stations.

Competition

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. We compete on the basis of the location of our plants and owning multiple plants in our regions, which increases the stability and reliability of our energy supply. Wholesale power generation is fundamentally a local business which, at present, is 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 we compete against from market to market.

Employees

As of December 31, 2005, the combined company has 3,682 employees, approximately 1,694 of whom were covered by U.S. bargaining agreements. During 2005, neither NRG nor Texas Genco experienced any significant labor stoppages or labor disputes at their facilities.

Energy Regulatory Matters

As operators of power plants and participants in wholesale energy markets, we are subject to regulation by various federal and state government agencies. These include FERC, NRC, PUCT and certain other state public utility commissions in which our generating assets are located. In addition, we are also subject to the market rules, procedures and protocols of the various ISO markets in which we participate.

The plant operations of, and wholesale electric sales from our Texas assets are not currently subject to regulation by FERC, as they are deemed to operate solely within the ERCOT and not in interstate commerce. As discussed below, these operations are subject to regulations by PUCT as well as to regulation by the NRC with respect to its ownership interest in the STP.

Federal Energy Regulatory Commission

FERC, among other things, regulates the transmission and wholesale sale of electricity in interstate commerce under the authority of the Federal Power Act, or FPA. In addition, under existing regulations,

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FERC determines whether an entity owning a generation facility is an Exempt Wholesale Generator, or EWG, as such was defined in the Public Utility Holding Company Act of 1935, or PUHCA of 1935. FERC also determines whether a generation facility meets the ownership and technical criteria of a Qualifying Facility, or QF, under Public Utility Regulatory Policies Act of 1978, or PURPA. Each of NRG s U.S. generating facilities has either been determined by FERC to qualify as a QF, or the subsidiary owning the facility has been determined to be an EWG.

The Energy Policy Act of 2005. EPAct 2005 was enacted into law on August 8, 2005. Among other things, EPAct 2005 repealed PUHCA of 1935, amended PURPA to remove statutory restrictions on utility ownership of a QF and to remove a utility s obligation to buy from a QF under certain circumstances, and enacted the Public Utility Holding Company Act of 2005, or PUHCA of 2005. EPAct 2005 s PUHCA changes became effective February 8, 2006. EPAct 2005 s amendments to PURPA were effective as of August 8, 2005. Though generally supported by the industry and viewed as a positive development, EPAct 2005 remains subject to FERC interpretation, and FERC has issued several rulemakings and rules to implement EPAct, some of which are still ongoing. NRG is currently assessing the effect of EPAct 2005 and these rulemakings issued by FERC to implement it on the company s regulatory environment and business.

Federal Power Act. The FPA gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and transmission of electricity in interstate commerce. Under the FPA, FERC, with certain exceptions, regulates the owners of facilities used for the wholesale sale of electricity or transmission in interstate commerce as public utilities. The FPA also gives FERC jurisdiction to review certain transactions and numerous other activities of public utilities. NRG s QFs are currently exempt from the FERC s rate regulation under Sections 205 and 206 of the FPA to the extent that sales are made pursuant to a contract established under PURPA and are not made under a market-based rate authorization from FERC.

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

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

Section 203 of the FPA requires FERC s prior approval for the transfer of control over assets subject to FERC s jurisdiction. EPAct 2005 amended this prior approval authority in a number of ways. In particular, transactions involving only generation assets which were previously exempt from FERC review under Section 203 of the FPA will now be subject to such review provided they meet the new $10 million threshold.

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The provisions of EPAct 2005 relating to prior approval of asset acquisitions under the FPA and FERC s rules promulgated thereafter became effective February 8, 2006.

PUHCA. As discussed above, EPAct 2005 repealed PUHCA of 1935, effective February 8, 2006, and replaces it with PUHCA of 2005. PUHCA of 2005 provides FERC with certain authority over and access to books and records of public utility holding companies not otherwise exempt by virtue of their ownership of EWGs, QFs and Foreign Utility Companies, or FUCOs. Because all of NRG s generating facilities have QF status or are owned through EWGs or FUCOs, NRG does not currently qualify as a holding company under PUHCA of 2005. As noted above, FERC has a rulemaking ongoing to implement PUHCA 2005, and several companies have sought clarification of FERC s rules.

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

Nuclear Regulatory Commission

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, our subsidiary Texas Genco, LP is an NRC licensee and is subject to NRC regulation. This NRC license gives it the right only to 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 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 Texas Genco, LP primarily focuses on its ability to meet its financial and decommissioning funding assurance obligations. In connection with the acquisition by Texas Genco of a 30.8% interest in STP from CenterPoint Energy, the NRC required Texas Genco to enter into a support agreement with Texas Genco, LP to provide up to $120 million to Texas Genco, LP if necessary to support operations at STP. Texas Genco entered into that support agreement on April 13, 2005. The support agreement remains in effect now that the Acquisition has been consummated.

Decommissioning Trusts. Upon expiration of the operating terms of the operation licenses for the two generating units at STP (currently scheduled for 2027 and 2028), the co-owners of STP are required under federal law to decontaminate and decommission STP. In May 2004, an outside consultant estimated a 44.0% share of the STP decommissioning costs to be approximately $650 million in 2004 dollars.

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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 periodic payments to the trust, plus allowable earnings, will equal the estimated decommissioning obligations needed by the time decommissioning is expected to begin. Currently, Texas Genco, LP s funding against its decommissioning obligation is contained within two separate trusts. PUCT regulations provide for the periodic funding of our decommissioning obligations through non-bypassable charges collected by CenterPoint Energy Houston Electric, LLC and AEP Texas Central Company, or CenterPoint Houston and AEP TCC, from their customers.

In the event that the funds from the trusts are ultimately determined to be inadequate to decommission the STP facilities, the original owners of our STP interests, CenterPoint Houston and AEP TCC, each will be required to collect, through their PUCT-authorized non-bypassable charges to customers, additional amounts required to fund the decommissioning obligations relating to our 44.0% share, provided that we have complied with the PUCT s rules and regulations regarding decommissioning trusts. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective rate payers of CenterPoint Houston or AEP TCC (or their successors).

Public Utility Commission of Texas

Our Texas subsidiaries are registered as power generation companies with PUCT. PUCT also has jurisdiction over power generation companies with regard to the administration of nuclear decommissioning trusts, PUCT state-mandated capacity auctions and the implementation of measures to mitigate undue market power that a power generation company may have and to remedy market power abuses in the ERCOT market and, indirectly, through oversight of ERCOT.

Regulatory Developments

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

We are affected by rule/tariff changes that occur in the existing ISOs. 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 (in particular, market power mitigation rules) to address some of the volatility in these markets. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy into the wholesale power markets. In addition, new approaches to the sale of electric power, in particular capacity, have been proposed, and it is not yet clear how they will operate in times of market stress or whether they will provide adequate compensation to generators over the long term.

Regional Businesses Market Developments

Texas (ERCOT) Region

Texas Nodal Protocols

At the direction of the PUCT, the ERCOT stakeholder process has developed the Texas Nodal Protocols that sets forth a complete and detailed revised wholesale market design based on locational marginal pricing (in place of the current ERCOT zonal market today). The stakeholder process took two years to complete and incorporates a variety of unique characteristics for a nodal market as the result of accommodations reached by parties in the stakeholder process. Major elements include bilateral energy and ancillary schedules, day-ahead energy market, resource specific energy and ancillary service bid curves, direct assignment of all congestion rents, nodal energy prices for generators, aggregation of nodal to zonal energy prices for loads, congestion revenue rights (including pre-assignment for public power entities), and pricing safeguards. The PUCT will consider approval of the Texas Nodal Protocols by early 2006 and has indicated January 1, 2009, as the date for full implementation of the new market design. Under the expedited schedule, the evidentiary hearing concluded December 13, 2005, and briefing by parties concluded January 27, 2006.

For a detailed discussion on market developments for the Northeast, South Central, Western and Other regions, please see Item 15 Note 26 to the Consolidated Financial Statements.

Environmental Matters

We are subject to a broad range of environmental and safety laws and 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 or during operation of power plants. Environmental laws have become increasingly stringent over time, particularly 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. It is not possible at this time to determine when or to what extent additional facilities, or modifications to existing or planned NRG facilities, will be required due to potential changes to environmental and safety laws and regulations, regulatory interpretations or enforcement policies. In general, future laws and regulations are expected to require the addition of emissions control or other environmental quality equipment or the imposition of certain restrictions on the operations of the combined company. We expect that future liability under, or compliance with, environmental requirements could have a material effect on our operations or competitive position.

U.S. Federal Environmental Initiatives

Air

On May 18, 2005, the US Environmental Protection Authority, or USEPA, published the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants. CAMR imposes limits on mercury emissions from new and existing coal-fired plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two phases (2010 and 2018). Consistent with the significant debate on whether the USEPA has authority to regulate mercury emissions through a cap-and-trade mechanism (as opposed to a command-and-control requirement to install maximum achievable control technology , or MACT, on a unit basis), 14 states, together with five environmental organizations, have filed petitions for reconsideration of CAMR. The states (including California, Connecticut, Delaware, Illinois, Maine, Massachusetts, New Hampshire, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, Vermont and Wisconsin) allege that the rule violates the Clean Air Act, or CAA, because it fails to treat mercury as a hazardous air pollutant. On August 4, 2005, the U.S. Court of Appeals for the District of Columbia Circuit denied the environmental petitioners request for a stay of CAMR. On October 28, 2005, the USEPA published notices of reconsideration of seven specific aspects of CAMR (including state allocations). Each of our coal-fired electric power plants will be subject to mercury regulation. However, since the rule has yet to be implemented by individual states and given the USEPA s pending reconsideration of the rule, it is difficult to assess with certainty how CAMR will affect our operations. Nevertheless, we continue to actively review emerging mercury monitoring and mitigation strategies and technologies to identify the most cost-effective options for NRG in implementing required mercury emission controls on the stipulated schedule.

On May 12, 2005, the USEPA published the Clean Air Interstate Rule, or CAIR. This rule applies to 28 Eastern States and the District of Columbia and caps SO_2 and NO_X emissions from power plants in two phases (2010 and 2015 for SO_2 and 2009 and 2015 for NO_X). CAIR will apply to certain of the combined company s power plants in New York, Massachusetts, Connecticut, Delaware, Louisiana, Illinois, Penn-

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sylvania, Maryland and Texas. States must achieve the required emission reductions through: (a) requiring power plants to participate in a USEPA-administered interstate cap-and-trade system; or (b) measures to be selected by individual states. On August 24, 2005, the USEPA published a proposed Federal Implementation Plan, or FIP, to ensure that generators affected by CAIR reduce emissions on schedule. In addition, on December 20, 2005, the USEPA signed proposed revisions to the National Ambient Air Quality Standards (NAAQS) for fine particulates (PM2.5) and inhalable coarse particulates (PM10-PM2.5), that would require affected states to implement further rules to address SO_2 and NO_X emissions (as precursors of fine particulates in the atmosphere). Further, on November 22, 2005, the USEPA granted requests to reconsider four specific aspects of CAIR (including the inclusion of certain states) with final action on reconsideration expected by March 15, 2006. While our current business plans include initiatives to address emissions (for example, the conversion of Huntley and Dunkirk to burn low sulfur coal), until the final CAIR rule and NAAQS for PM2.5, PM10-2.5 and ozone are actually implemented by specific state legislation, it is not possible to identify with greater specificity the effect of CAIR on us. As noted below, certain states in which we operate have already announced plans to implement emissions reductions that go beyond the CAIR requirements. It is possible that investments in additional backend control technologies will be required and we continue to evaluate these issues.

Although we recognize the uncertainties regarding how CAMR and CAIR will be implemented, we expect to incur a substantial increase in our environmental capital expenditures between 2009 and 2012 in order to ensure compliance with CAMR and CAIR. We have currently estimated expenditures of around $540 million for CAMR and CAIR compliance during this period for the NRG facilities most of which would be incurred at our various coal-fired plants in the Northeast region and South Central region. We have currently estimated our total capital expenditures for compliance with air pollution control regulations from 2006 to 2014 at the NRG facilities at approximately $675 million.

From 1999 through 2005, Texas Genco invested approximately $700 million for NO_X emissions controls at its plants. These emissions controls were installed to comply with regulations adopted by the Texas Commission on Environmental Quality, or TCEQ, to attain the one-hour NAAQS for ozone, as well as provisions of the Texas electric restructuring law. As a result, emissions from our plants in the Houston-Galveston area have been reduced by approximately 88% from 1998 levels and our Texas fleet overall operates at one of the lowest NO_X emissions rates in the country. In aggregate, our Texas plants are in compliance with current NO_X emission limits and are not expected to incur material environmental capital expenditures to ensure NO_X emissions compliance in the next several years. The TCEQ has, however, initiated a rulemaking process for establishing lower NO_X emissions limits to assure compliance with the USEPA 8-hour ozone standard in the Houston-Galveston and Dallas-Fort Worth areas. It is possible that any new regulations implemented may require additional NO_X emission controls on the Texas plants in 2009 or beyond. We have currently estimated approximately $70 million in additional capital expenditures with respect to compliance with air pollution control requirements (primarily replacement of catalyst for NO_X emission controls) between 2006 and 2014.

The USEPA had also proposed MACT standards for nickel from oil-fired units that would essentially require the installation of electrostatic precipitators on certain oil-fired units. These proposed requirements were originally included in drafts of CAMR. However, reflecting further dialogue with generation industry participants and additional scientific review, the nickel MACT provisions were omitted from CAMR. In fact, the USEPA issued a delisting rule on March 29, 2005 effectively removing the MACT standards for nickel (i.e., specific control technologies to be installed at each affected plant) at oil-fired power plants. A number of environmental groups lodged legal challenges to the USEPA s delisting rule and the agency has agreed to reconsider this delisting, although it has not specified which issues will be reconsidered. As the delisting challenge relates to both nickel from oil-fired power plants and mercury from coal-fired plants, it is not possible to predict the outcome of the pending legal action.

NRG s facilities in the eastern United States are subject to a cap-and-trade program governing NO_X emissions during the ozone season (May 1 through September 30). These rules essentially require that one NO_X allowance be held for each ton of NO_X emitted from fossil fuel-fired stationary boilers, combustion turbines, or combined cycle systems. Each of NRG s facilities that is subject to these rules has been allocated

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NO_X emissions allowances. NRG currently estimates that the portfolio total is currently sufficient to generally cover operations at these facilities through 2009. However, if at any point allowances are insufficient for the anticipated operation of each of these facilities, NRG must purchase NO_X allowances. Any obligation to purchase a substantial number of additional NO_X allowances could have a material adverse effect on NRG s operations.

The Clean Air Visibility Rule (or so-called BART rule) was published by the USEPA on July 6, 2005. This rule is designed to improve air quality in national parks and wilderness areas. The rule requires regional haze controls (by targeting SO_2 and NO_X emissions from sources including power plants of a certain vintage) through the installation of Best Available Retrofit Technology, or BART, in certain cases. States must develop implementation plans by December 2007 which may be satisfied through an emissions trading program for BART sources. Although the BART rule will apply to many of the Company s facilities, sources that are also subject to CAIR (which include most of our facilities) will likely be able to satisfy their obligations under the BART rule through compliance with the more stringent CAIR. Accordingly, no material additional expenditures are anticipated for compliance with the Clean Air Visibility Rule, beyond those required by CAIR.

In addition to federal regulation, national legislation has been proposed that would impose annual caps on U.S. power plant emissions of NO_X, SO_2, mercury, and, in some instances, CO_2. While the Administration s proposed Clear Skies Act (which would regulate the aforementioned pollutants except for CO_2) stalled in Senate Committee on March 9, 2005, the Bush Administration continues to support this legislation. Clear Skies overlaps significantly with CAIR and CAMR, and would likely modify or supersede those rules if enacted as federal legislation as proposed.

Twelve states and various environmental groups filed suit against the USEPA seeking confirmation that the USEPA has an existing obligation to regulate greenhouse gases, or GHGs, under the CAA. On July 15, 2005, the US Court of Appeals for the District of Columbia Circuit (in *Commonwealth of Massachusetts v. EPA*) supported the USEPA s refusal to regulate GHG emissions from motor vehicles, although avoiding the broader issue of whether USEPA has authority, or an obligation, to regulate GHGs under the CAA. On September 1, 2005, five states requested reconsideration of this dismissal. While the specific issue under consideration is the USEPA s obligation to require GHG cuts from mobile sources, any decision implying that the USEPA has an obligation to regulate GHGs nationally has wider implications for the power generation sector. In 2004, eight states and the City of New York filed suit in the U.S. District Court for the Southern District of New York against American Electric Power Company, Southern Company, Tennessee Valley Authority, Xcel Energy, Inc. and Cinergy Corporation, alleged to be the nation s five largest emitters of GHGs and all of which are owners of electric generation (*Connecticut v. AEP*). An injunction was sought against each defendant to force it to abate its contribution to the global warming nuisance by requiring CO_2 emissions caps and annual reductions in those caps for at least a decade. On September 15, 2005, the public nuisance case was dismissed on the basis that the claims made raised political questions reserved to the legislative and executive branches of the federal government. On September 20, 2005, plaintiffs filed an appeal of this decision with the US Court of Appeals for the Second Circuit. The initiation of GHG-related litigation and proposed legislation is becoming more frequent, although the outcomes of such suits or proposed litigation cannot be predicted. Although NRG has not been named as a defendant in any related suits to date, the outcome of such suits could affect the overall regulation of GHGs under the CAA. Our compliance costs with any mandated GHG reductions in the future could be material. See also Regional U.S. Environmental Regulatory Initiatives, below.

In the 1990s, the USEPA commenced an industry-wide investigation of coal-fired electric generators to determine compliance with environmental requirements under the CAA associated with repairs, maintenance, modifications and operational changes made to facilities over the years. As a result, the USEPA and several states filed suits against a number of coal-fired power plants in mid-western and southern states alleging violations of the CAA NSR/ Prevention of Significant Deterioration, or PSD, requirements. In one of the more prominent suits of this type, involving Ohio Edison, a subsidiary of First Energy, the USEPA reached settlement on March 18, 2005 for NSR issues with respect to all coal-fired plant located in Ohio, obligating First Energy to spend $1.1 billion to install pollution control equipment through 2010. In another similar suit, on June 15, 2005 the USEPA appeal in the Duke Energy case was heard with the U.S. Court of Appeals for the Fourth Circuit holding in favor of Duke s position as to what type of modification triggers NSR and PSD provisions. Rehearing petitions filed in this matter by the Department of Justice and some environmental groups were denied on August 30, 2005. On December 28, 2005, further petitions were filed by environmental groups requesting Supreme Court review of this decision. On June 3, 2005, the U.S. District Court for the Northern District of Alabama reached conclusions favorable to Alabama Power through the court s interpretation of NSR rules relating to routine maintenance, repair and replacement, or RMRR, and the correct test for determining a significant net emissions increase. However, divergent rulings exist on NSR issues across the country, with courts in Ohio and Indiana providing interpretations of the NSR provisions different from those in the Duke and Alabama cases. For example, on August 29, 2005, U.S. District Court for the Southern District of Indiana ruled in *U.S. v. Cinergy* in favor of the USEPA and specifically rejected the conclusion in the Duke case.

In an effort to revise the legal requirements as to what amounts to a major modification and what emissions tests apply, USEPA issued its NSR Reform Rule on December 31, 2002, although its implementation was stayed by court order on December 24, 2003. There have been a number of legal challenges to different aspects of the proposed rule. On October 13, 2005 USEPA proposed changes to its NSR permitting program to stipulate an emissions test standard based on hourly emission rates, rather than aggregate annual emissions.

Given the divergent cases and rules in this area (at both the federal and state levels), it is difficult to predict with certainty the parameters of the final NSR/ PSD regime. However, in October 2005, the USEPA announced that due to the promulgation of programs such as CAIR and the Clean Air Visibility Rule, it is placing a lower priority on continued enforcement of suspected NSR/ PSD violations. In the meantime, we continue to analyze all proposed projects at our facilities to ensure ongoing compliance with the applicable legal requirements.

Water

In July 2004, USEPA published rules governing cooling water intake structures at existing power facilities (the Phase II 316(b) Rules). The Phase II 316(b) Rules specify certain location, design, construction and capacity standards for cooling water intake structures at existing power plants using the largest amounts of cooling water. These rules will require implementation of the Best Technology Available, or BTA, for minimizing adverse environmental impacts unless a facility shows that such standards would result in very high costs or little environmental benefit. The Phase II 316(b) Rules require our facilities that withdraw water in amounts greater than 50 million gallons per day (and utilize at least 25% for cooling purposes) to submit certain surveys, plans and operational and restoration measures (with wastewater permit applications or renewal applications) that would minimize certain adverse environmental impacts of impingement or entrainment. The Phase II 316(b) Rules affect a number of NRG s plants, specifically those with once-through cooling systems. Compliance options include the addition of control technology, modified operations, restoration or a combination of these, and are subject to a comparative cost and cost/benefit justification. While NRG has conducted a number of the requisite studies, until all the needed studies throughout our fleet have been completed and consultations on the results have occurred with USEPA (or its delegated state or regional agencies), it is not possible to estimate with certainty the capital costs that will be required for compliance with the Phase II 316(b) Rules, although current estimates for the combined company s facilities involve capital expenditures and related costs of around $80 million between 2006 and 2012. In addition, the Phase II Rules have been challenged by industrial and environmental groups and the outcome of this litigation could affect our obligations pursuant to these rules. Further, Phase III rules, which were proposed in November 2004, may be applicable to some of our smaller power plants when finalized.

Nuclear Waste

Under the U.S. Nuclear Waste Policy Act of 1982, the federal government must remove and ultimately dispose of spent nuclear fuel and high-level radioactive waste from nuclear plants such as STP. Consistent with the Act, owners of nuclear plants, including NRG and the other owners of STP, entered into contracts

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setting out the obligations of the owners and the U.S. Department of Energy, or DOE, including the fees being paid by the owners for DOE s services. Since 1998, the DOE has been in default on its obligations to begin removing spent nuclear fuel and high-level radioactive waste from reactors. On January 28, 2004, Texas Genco LP and the other owners of STP filed a breach of contract suit against the DOE in order to protect against the running of a statute of limitations.

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended, the state of Texas is required to provide, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the state. The state of Texas has agreed to a compact with the states of Maine and Vermont for a disposal facility that would be located in Texas. That compact was ratified by Congress and signed by President Clinton in 1998. In 2003, the state of Texas enacted legislation allowing a private entity to be licensed to accept low-level radioactive waste for disposal. We intend to continue to ship low-level waste material from STP off-site 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 Regulatory Initiatives

Texas (ERCOT) Region. The USEPA s Region VI (which includes Texas, Louisiana, and three other states) indicated in September 2004 that it intends to evaluate 75%-80% of the coal-fired power plants in its region over the next several years for potential violations of the NSR program or PSD. During air emissions inspections of the Limestone plant in November 2004, a USEPA inspector informally advised Texas Genco that the USEPA has drafted, but not yet sent, an information request letter pursuant to Section 114 of the CAA concerning potential NSR or PSD issues at the Limestone plant. As of March 3, 2006, NRG has not received this letter and has not had any further communications on this issue with the USEPA.

Northeast Region. Massachusetts air regulations prescribe schedules under which six existing coal-fired power plants in-state are required to meet stringent emission limits for NO_X, SO_2, mercury, and CO_2. The state has reserved the issue of control of carbon monoxide and particulate matter emissions for future consideration. Our Somerset plant is subject to these regulations. NRG has installed natural gas re-burn technology to meet the NO_X and SO_2 limits. On June 4, 2004, the Massachusetts Department of Environmental Protection, or MADEP, issued its regulation on the control of mercury emissions. The effect of this regulation is that starting October 1, 2006, Somerset will be capped at 13.1 lbs/year of mercury and as of January 1, 2008, Somerset must achieve a reduction in its mercury inlet-to-outlet concentration of 85%. We plan to meet the requirements through the management of our fuels and the use of early and off-site reduction credits. Additionally, NRG has entered into an agreement with MADEP to retire or repower the Somerset station by the end of 2009.

The Massachusetts carbon regulation 310 CMR 7.29 Emissions Standards for Power Plants requires coal-fired generation located within the state to comply with CO_2 emission restrictions. A carbon emissions cap applies beginning January 1, 2006, while a rate requirement will apply in 2008. This regulation means that if CO_2 emissions at our Somerset facility exceed the annual cap from 2006, then the excess must be offset with approved CO_2 credits. However, since there are currently no approved CO_2 credits for use in Massachusetts, MADEP has proposed that generators annually report overages, starting in 2006, and at the time that there is a an established CO_2 market operating in the state, NRG would be required to purchase or generate sufficient CO_2 credits to offset the balance. On December 20, 2005, Massachusetts issued proposed revisions to the CO_2 regulations, including a proposed implementing regime that could allow the use of on-site and off-site generated CO_2 credits, with a price backstop of $10/ton. MADEP expects to finalize these revisions in spring 2006. Massachusetts was involved in the initial negotiations regarding the Regional Greenhouse Gas Initiative, or RGGI, which is discussed below, but did not enter into the Memorandum of Understanding with other northeastern states. Given the regulatory uncertainty surrounding implementation of Massachusetts s carbon market and the corresponding costs of CO_2 allowances when that market exists, Somerset could be materially affected if it does not retire by the end of 2009.

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Pursuant to New York State Department of Environmental Conservation, or NYSDEC, rules (the Acid Deposition Reduction Program, ADRP) fossil-fuel-fired combustion units in New York must reduce SO_2 emissions to 25% below the levels allowed in the federal Acid Rain Program starting January 2005 and to 50% below those levels starting in January 2008. In addition, under ADRP generators now also have to meet the ozone season NO_X emissions limit year-round. Our strategy for complying with the ADRP involves the generation of early reductions of $SO_2$and NO_X emissions associated with fuel switching and use such reductions to extend the timeframe for implementing technological controls, which could ultimately include the addition of flue gas desulfurization, or FGD, and selective catalytic reduction, or SCR, equipment. On January 11, 2005, NRG reached an agreement with the State of New York and the NYSDEC in connection with emissions reductions at the Huntley and Dunkirk facilities, as discussed below in Legal Proceedings. The Consent Decree was entered by the U.S. District Court for the Western District of New York on June 3, 2005. NRG does not anticipate that any additional material capital expenditures, beyond those already spent, will be required for our Huntley and Dunkirk plants to meet the current compliance standards under the Consent Decree through 2010, although, this does not reflect any additional capital expenditures that may be required to satisfy other federal and state laws.

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC entered into a Consent Order with NYSDEC, effective March 31, 2004, regarding certain alleged opacity exceedances. The Consent Order required the respondents to pay a civil penalty of $1.0 million which was paid in April 2004. The Order also stipulates penalties (payable quarterly) for future violations of opacity requirements and a compliance schedule. NRG recently resolved a dispute with NYSDEC over the method of calculation for stipulated penalties. NRG paid NYSDEC $1.1 million at the end of 2005 to cover the stipulated penalty payments that had been withheld pending resolution of the dispute.

While no rules affecting NRG s existing facilities have been formally proposed, Delaware has recently issued a Start Action Notice to impose emissions standards for SO_2, NO_X and mercury. Delaware is pursuing such rule-making based on recent determinations that portions of the state are in non-attainment for NAAQS for fine particulates, and all of the state is in non-attainment for the NAAQS for 8-Hour Ozone. We are evaluating emissions reduction opportunities which may include blending low sulfur western coals. NRG is actively participating in the Delaware rule-making as a stakeholder and will continue to be involved in environmental policy-making efforts in Delaware through the Governor s Energy Task Force and interactions with legislators, the PSC and the Delaware Department of Natural Resources and Environmental Control, or DNREC.

The Ozone Transport Commission, or OTC, was established by Congress and governs ozone and the NO_X budget program in certain eastern states, including Massachusetts, Connecticut, New York and Delaware. In January 2005, the OTC redoubled its efforts to develop a multi-pollutant regime (SO_2, NO_X , mercury and CO_2) that is expected to be completed by mid-2006 (with individual state implementation to follow). On June 8, 2005, the OTC members unanimously resolved to implement CAIR-Plus emissions regulations, based on concerns that the USEPA s CAIR fails to achieve attainment of 8-hour ozone and fine particulate matter. As a result, the OTC proposes to implement a regional plan containing emissions reduction targets for power plants that exceed those under CAIR. The OTC targets and timelines are as follows: (a) through September 2006: write model rule, with participating states signing a Memorandum of Understanding; (b) by December 2006 states file their implementation plans or reduction regulations; (c) 2008 Phase I reductions of NO_X (to 1.87 million tons) and SO_2 (to 3.0 million tons) apply; (d) 2012 Phase II reductions of NO_X (to 1.28 million tons) and SO_2 (to 2.0 million tons) apply; and (e) 2015 90% mercury removal required. OTC s proposed CAIR-Plus involves emissions reductions which are both sooner and more aggressive than CAIR (e.g., aggregate NO_X reductions would be 25% greater than CAIR, while SO_2 reductions would be 33% greater than CAIR). NRG continues to be engaged in the OTC stakeholder process. While it is not possible to predict the outcome of this regional legislative effort, to the extent that the OTC is successful in implementing emissions requirements that are more stringent than existing regimes (including the recently reached New York settlement), NRG could be materially impacted.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap-and-trade GHG program for electric generators, referred to as the

Regional Greenhouse Gas Initiative, or RGGI. The model RGGI rule is scheduled to be announced within the next few months, with an estimate of two to three years for participating states to finalize implementing regulations. The current proposal is for the program to start in 2009, with a review in 2015 and an assessment of further reductions after 2020. The proposal involves an overall RGGI cap (with state sub-caps) based on CO_2 emissions for the period 2000 to 2004. That cap, referred to as stabilization, will remain the same through 2015, with a 10% reduction between 2015 and 2020. Decisions on allowance allocations will be made by each state, although at least 25% of the state allocations will be set aside for public purposes, suggesting that from implementation, generators in the RGGI region may receive an allocation of allowances that is materially less than required to cover existing emissions, potentially having a significant effect on the cost of operations. While the details of the model rule are still under development, when RGGI is implemented, our plants in New York, Delaware and Connecticut may be materially affected. If Massachusetts, which was originally involved in the development of RGGI, decides to participate, NRG s plant in that state may also be affected.

South Central Region. The Louisiana Department of Environmental Quality, or LADEQ, has promulgated State Implementation Plan revisions to bring the Baton Rouge ozone non-attainment area into compliance with applicable NAAQS. NRG participated in development of the revisions, which require the reduction of NO_X emissions at the gas-fired Big Cajun I Power Station and coal-fired Big Cajun II Power Station to 0.1 lbs/ MMBtu and 0.21 lbs/ MMBtu NO_X, respectively (both based on heat input). This revision of the Louisiana air rules would constitute a change-in-law covered by agreement between Louisiana Generating, LLC and the electric cooperatives (power off-takers), allowing nearly all of the costs of added combustion controls to be passed through to the cooperatives. The combustion controls required at the Big Cajun II Generating Station to meet the state s NO_X regulations have been installed.

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request for information under Section 114 of the CAA from USEPA seeking information primarily related to physical changes made at Big Cajun II and subsequently received a notice of violation, or NOV, based on alleged NSR violations. See Legal Proceedings for a discussion of this matter. NRG is up-to-date with all USEPA information requests it has received in connection with this matter and has not been contacted by USEPA pursuant to the NOV since May 2005.

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

On October 6, 2005, the California Public Utilities Commission, or CPUC, adopted a policy statement on GHG Performance Standards as part of a focus on emissions from conventional fossil-fuel resources. The adopted policy statement directs the CPUC to investigate a GHG emissions performance standard for energy procurement by the state s Investor-Owned Utilities, or IOUs, that is no higher than the GHG emissions levels of a combined-cycle natural gas turbine for all energy procurement contracts longer than three years in length and for all new IOU owned generation. On January 13, 2006, the CPUC issued a draft decision establishing a load-based GHG emission cap that will apply to IOUs. While the decision doesn t establish specific caps, it does indicate a preference for using 1990 emissions as the preferred baseline year. The decision also restricts IOUs from entering into power purchase agreements with generators unless the generator reports its GHG emissions through the California Climate Action Registry. West Coast Power is a member of the Registry and will be finalizing its 2004 GHG inventory by the end of February 2006. The CPUC is obligated to evaluate and decide on the details of the GHG cap and trading program under the recent draft decision by, ,as part of either an existing or new CPUC rulemaking sometime in 2006.

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On February 9, 2006, the California State Lands Commission (CSLC) postponed an agenda item regarding, Commission consideration of a resolution supporting the elimination of once through cooling in California power generation facilities. The draft resolution urges the California State Water Resource Control Board and the California Energy Commission to develop policies that eliminate once through cooling systems at new and existing power plants in California. The draft resolution also requires that the CSLC not approve new or extended leases for power plants utilizing once through cooling systems after 2020. This resolution, if adopted, would affect the long term operation of the once through cooling systems at the El Segundo and Encina power stations as both systems rely on submerged land leases with the CSLC and both of which are currently undergoing lease renewals. Under pressure from power and desalination water industry groups, the CSLC agreed to postpone the agenda item until the April 27, 2006 Commission meeting in order to better understand the costs and impacts associated with the decision.

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. We may also be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by a party in connection with hazardous material releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, or CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, or SARA, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under such laws to be strict (without fault) and joint and several. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. Cleanup obligations can often be triggered during the closure or decommissioning of a facility, in addition to spills or other occurrences during our operations.

On January 18, 2005, NRG Indian River Operations, Inc. received a letter of informal notification from DNREC stating that it may be a potentially responsible party with respect to the Burton Island Landfill, along with Delmarva Power. The letter signals only that an investigation is to be commenced and is not a conclusive determination. Further, the Burton Island Landfill is a site that would potentially qualify for a remedy under a Voluntary Cleanup Program or VCP. We have signaled our interest in being considered for a VCP should matters progress. With the exception of the foregoing, neither NRG nor Texas Genco have been named as a potentially responsible party with respect to any off-site waste disposal matter.

Texas (ERCOT) Region. The lignite used to fuel the Limestone facility is obtained from a surface mine adjacent to the facility under an amended long-term contract with Texas Westmoreland Coal Co., or TWCC, entered into in August 1999. TWCC is responsible for performing ongoing reclamation activities at the mine until all lignite reserves have been produced. When production is completed at the mine, Texas Genco is responsible for final mine reclamation obligations. The Railroad Commission of Texas has imposed a bond obligation of approximately $70 million on TWCC for the reclamation of this lignite mine. Final reclamation activity is expected to commence in 2015. Pursuant to the contract with TWCC, an affiliate of CenterPoint Energy, Inc. has guaranteed $50 million of this obligation until 2010. The remaining sum of approximately $20 million has been bonded by the mine operator, TWCC. Under the terms of Texas Genco s agreement, Texas Genco is required to post a corporate guarantee in the amount of $50 million of TWCC s reclamation bond when CenterPoint s obligation lapses. As of December 31, 2005, Texas Genco had accrued approximately $17 million related to the mine reclamation obligation.

Further details regarding our Domestic Site Remediation obligations for the Northeast, South Central and Western regions can be found at Item 15 Note 27 to the Consolidated Financial Statements.

International Environmental Matters

Most of the foreign countries in which NRG owns or may acquire or develop independent power projects have environmental and safety laws or regulations relating to the ownership or operation of electric power

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generation facilities. These laws and regulations, like those in the U.S., are constantly evolving and have a significant impact on international wholesale power producers. In particular, NRG s international power generation facilities will likely be affected by emissions limitations and operational requirements imposed by the Kyoto Protocol, which is an international treaty related to greenhouse gas emissions which entered into force on February 16, 2005, and country-based restrictions pertaining to global climate change concerns.

We retain appropriate advisors in foreign countries and seek to design our international asset management strategy to comply with each country s environmental and safety laws and regulations. There can be no assurance that changes in such laws or regulations will not adversely effect our international operations.

Australia. With respect to Australia, climate change is considered a long-term issue (e.g. 2010 and beyond) and the Australian government s response to date has included a number of initiatives, all of which have had no or minimal impact on our operations. The Australian government has stated that Australia will achieve its Kyoto Protocol target of 8% below 1990 greenhouse gas emission levels for the 2008 to 2012 reporting period, but that Australia will not ratify the Kyoto Protocol. Each Australian state government is considering implementing a number of climate change initiatives that will vary considerably state to state, with the possible exception of an inter-jurisdictional state-led carbon trading proposal (which is not supported by the federal government).

NRG Flinders disposes of ash to slurry ponds at Port Augusta in South Australia. At the end of life of the power station, NRG Flinders will have an obligation to remediate these ponds in accordance with a plan accepted by the South Australian Environment Protection Agency and confirmed in the Environment Compliance Agreement between the South Australian Minister for Environment and Heritage and NRG Flinders dated September 20, 2000, or the EC Agreement. The estimated cost of remediation including contingencies according to the plan is AUD 2.0 million (approximately $1.5 million). There is no timeline associated with the obligation, but the EC Agreement extends to 2025. Under these arrangements, required remediation relates to surface remediation and does not entail any groundwater remediation.

MIBRAG/ Schkopau, Germany. While CO_2 emissions trading began in Germany in 2005, pursuant to European Union obligations under the Kyoto Protocol, we do not currently expect the CO_2 trading program to be a material constraint on our business in Germany. Changes to the German Emission Control Directive will result in lower NO_X emission limits for plants firing conventional fuels (Section 13 of the Directive) and co-firing waste products (Section 17 of the Directive). The new regulations will require the Mumsdorf and Deuben Power stations to install additional controls to reduce NO_X emissions in 2006. These plant modifications are proceeding on schedule.

The European Union s Groundwater Directive and Mine Wastewater Management Directive are in the rule-making stage with the final outcome still under debate. Given the uncertainty regarding the possible outcome of the debate on these directives, we cannot quantify at this time the effect such requirements would have on our future coal mining operations in Germany.

A new law specifically dealing with the relocation of the residents of Heuersdorf from the path of the mining plan was enacted by the legislature of Saxony in 2004. On November 25, 2005, the Saxony Constitutional Court upheld the constitutionality of the Heuersdorf act. This ruling cannot be appealed. Nuisance suits remain a possibility, but the court s ruling brings the matter closer to final resolution.

The supply contracts under which MIBRAG mines lignite from the Profen mine expire on December 31, 2021. The contracts under which MIBRAG mines lignite from the Schleenhain mine expire in 2041. At the end of each mine s productive lifetime, MIBRAG will be required to reclaim certain areas. MIBRAG accrues for these eventual expenses and estimates the cost of the final reclamation to approach approximately 176 million in the instance of the Schleenhain mine and 132 million for Profen.

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Insurance

General

NRG carries insurance coverage consistent with companies engaged in similar commercial operations with similar properties, including business interruption insurance for the coal and lignite plants. However, NRG s insurance policies are subject to certain limits and deductibles as well as policy exclusions. Adequate insurance coverage in the future may be more expensive or may not be available on commercially reasonable terms. Also, the insurance proceeds received for any loss of or any damage to any of our generation plants may not be sufficient to restore the loss or damage without negative impact on our financial condition, results of operations or cash flows.

NRG believes that the insurance program that is presently in effect for NRG after its acquisition of Texas Genco is consistent with prudent industry practice.

Nuclear

NRG and the other owners of STP maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of STP currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum. STPNOC currently carries accidental outage coverage with a 17 week deductible and a six week indemnity at a rate of $3.5 million per week. This coverage may not be available on commercially renewable terms or may be more expensive in the future and any proceeds from such insurance may not be sufficient to indemnify the owners of STP for their losses. NRG has also purchased additional accidental outage coverage for its ownership percentage in STP. This coverage will provide maximum weekly indemnity of $1.98 million for 52 weeks and $1.584 million per week for the next 104 weeks after the 17-week waiting period and six-week indemnity period have been met. These figures are per unit and if more than one unit experiences an outage from the same accident, the weekly indemnity is limited to 80% of the single unit recovery when both units are out of service.

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. For such claims in excess of $300 million per reactor, NRG and the other owners of STP are liable for any single incident, whether it occurs at STP or at another nuclear power plant not owned by it, up to a cap of $95.8 million per reactor in retrospective premiums for such incident but not to exceed $15 million per year in each case as adjusted for future inflation. These amounts are assessed per each licensed reactor. STP is a two reactor facility and our liability is capped at 44.0% of these amounts due to our 44.0% interest in STP. 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 our financial condition, results of operations or cash flows.

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

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

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

Our financial performance may be impacted by future decreases in oil and natural gas prices, significant and unpredictable price fluctuations in the wholesale power markets and other market factors that are beyond our control.

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

We sell all or a portion of the energy, capacity and other products from many of our facilities to wholesale power markets, including energy markets operated by independent system operators, or ISOs, or regional transmission organizations, as well as wholesale purchasers. We are generally not entitled to traditional cost-based regulation, therefore we sell electric generation capacity, power and ancillary services to wholesale purchasers at prices determined by the market. As a result, we are not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations depend upon current and forward market prices for power.

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

- increases and decreases in generation capacity in our markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation plants, expansion of existing plants or additional transmission capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- electric supply disruptions, including plant outages and transmission disruptions;
- 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;
- availability of competitively priced alternative power sources;
- development of new fuels and new technologies for the production of power;
- natural disasters, wars, embargoes, terrorist attacks and other catastrophic events;

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regulations and actions of the ISOs; and

federal and state power market and environmental regulation and legislation.

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

Our costs, results of operations, financial condition and cash flows could be adversely impacted by disruption of our fuel supplies.

We rely on coal, oil and natural gas to fuel our power generation facilities. Delivery of these fuels to our 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, we are subject to the risks of disruptions or curtailments in the production of power at our generation facilities if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure.

The company has sold forward a substantial part 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 our obligations under these forward power sales contracts, we have entered into long-term and short-term contracts for the purchase and delivery of fuel. Many of our forward power sales contracts do not allow us to pass through changes in fuel costs or discharge the company s 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 our fuel supplies may therefore require us to find alternative fuel sources at higher costs, to find other sources of power to deliver to counterparties at 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 our financial performance.

We also buy significant quantities of fuel on a short-term or spot market basis. Prices for all of our fuels fluctuate, sometimes rising or falling significantly over a short period. The price we 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 our 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 of electricity, gas or coal transmission or transportation, infrastructure or other constraints or inefficiencies;

additional generating capacity;

availability of competitively priced alternative energy sources;

availability and levels of storage and inventory for fuel stocks;

natural gas, crude oil, refined products and coal production levels;

the creditworthiness or bankruptcy or other financial distress of market participants;

changes in market liquidity;

natural disasters, wars, embargoes, acts of terrorism and other catastrophic events;

- federal, state and foreign governmental regulation and legislation; and

- our creditworthiness and liquidity and willingness of fuel suppliers/transporters to do business with us.

Our plant operating characteristics and equipment, particularly at our coal-fired plants, often dictate the specific fuel quality to be combusted. The availability and price of specific fuel qualities may vary due to

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supplier financial or operational disruptions, transportation disruptions and force majeure. At times, coal of specific quality may not be available at any price, or we may not be able to transport such coal to our facilities on a timely basis. In such case, we may not be able to run a coal facility even if it would be profitable. Operating a coal facility with lesser quality coal can lead to emission or operating problems. If we had sold forward the power from such a coal facility, we 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 our results of operations.

There may be periods when we will not be able to meet our commitments under our forward sales obligations at a reasonable cost or at all.

A substantial portion of the output from NRG s units is sold forward under fixed price power sales contracts through 2010, and we also sell forward the output from our intermediate and peaking facilities when we deem it commercially advantageous to do so. Because our obligations under most of these agreements are not contingent on a unit being available to generate power, we are 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 we do not have sufficient lower cost capacity to meet our commitments under our forward sales obligations, we would be required to supply replacement power either by running our other, higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. If we failed to deliver the contracted power, then we would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

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

Our trading operations and the use of hedging agreements could result in financial losses that negatively impact our results of operations.

We enter 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 our power generation operations. These activities, although intended to mitigate price volatility, expose us to other risks. When we sell power forward, we give 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 us to post significant amounts of cash collateral or other credit support to our counterparties. Further, if the values of the financial contracts change in a manner we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our business, operating results or financial position.

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon movement in commodity prices.

We may engage in trading activities, including the trading of power, fuel and emissions credits that are not directly related to the operation of our 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. We would expect to settle these trades financially rather than through the production of power or the delivery of fuel. This trading activity may expose us to the risk of significant financial losses which could have a material adverse effect on our business and financial condition.

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

We are exposed to market risks through our 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.

We undertake these marketing activities through agreements with various counterparties. Many of our agreements with counterparties include provisions that require us to provide guarantees, offset of netting arrangements, letters of credit, a second lien on assets and/or cash collateral to protect the counterparties against the risk of our 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 our being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of our strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than we anticipate or are able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as cash margin, we may not be able to manage price volatility effectively or to implement our strategy. An increase in demands from our counterparties to post letters of credit or cash collateral may negatively affect our liquidity position and financial condition.

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

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

We engage in commodity-related marketing and price-risk management activities in order to economically hedge our exposure to market risk with respect to:

- electricity sales from our generation assets;
- fuel utilized by those assets; and
- emission allowances.

We generally attempt to balance our fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations, through the use of financial and physical derivative contracts. These derivatives are accounted for in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. SFAS No. 133 requires us 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 hedge accounting treatment. Whether a derivative qualifies for hedge accounting depends upon it meeting specific criteria used to determine if hedge accounting is and will remain appropriate for the term of the derivative. Economic hedges will not necessarily qualify for hedge accounting treatment. As a result, we are unable to predict the impact that our risk management decisions may have on our quarterly and annual operating results.

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

We have numerous competitors in all aspects of our business, and additional competitors may enter the industry. Because many of our facilities are old, newer plants owned by our competitors are often more efficient than our aging plants, which may put some of our plants at a competitive disadvantage to the extent

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our competitors are able to consume the same fuel as we consume at those plants. Over time, our plants may be squeezed out of their markets, or may be unable to compete with these more efficient plants.

In our power marketing and commercial operations, we compete on the basis of our 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, we seek 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 we compete may have greater liquidity, 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 we do.

Our 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 we 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 we will be able to compete successfully against current and future competitors, and any failure to do so would have a material adverse effect on our business, financial condition, results of operations and cash flow.

Operation of power generation facilities involves significant risks that could have a material adverse effect on our revenues and results of operations.

The ongoing operation of our 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 our product to our 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 our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWh or require us to incur significant costs as a result of running one of our higher cost units or obtaining replacement power from third parties in the open market to satisfy our forward power sales obligations. Our inability to operate our plants efficiently, manage capital expenditures and costs, and generate earnings and cash flow from our asset-based businesses in relation to our debt and other obligations could have a material adverse effect on our results of operations, financial condition or cash flows.

While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover our lost revenues, increased expenses or liquidated damages payments should we experience equipment breakdown or non-performance by contractors or vendors.

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 our revenues and results of operations.

Many of our facilities are old and are likely to 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.

We 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 our financial performance and condition.

If we make any major modifications to our power generation facilities, we may be required to install the best available control technology or to achieve the lowest achievable emissions rate, 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.

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

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

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

Supplier and/or customer concentration at certain of our facilities may expose us to significant financial credit or performance risks.

We often rely 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 our facilities. If these suppliers cannot perform, we utilize the marketplace to provide these services. There can be no assurance that the marketplace can provide these services.

At times, we rely 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. We have hedged a portion of our 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. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement power purchase agreements, we would sell our plants power at market prices. If we were unable to enter into replacement fuel or fuel transportation purchase agreements, we would seek to purchase our plants fuel requirements at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price.

In the past several years, a substantial number of companies, some of which serve as our counterparties from time to time, have experienced downgrades in their credit ratings. The failure of any supplier or customer to fulfill its contractual obligations to us could have a material adverse effect on our financial results.

Consequently, the financial performance of our facilities is dependent on the credit quality of, and continued performance by, suppliers and customers.

We rely on power transmission facilities that we do not own or control and are subject to transmission constraints within a number of our core regions. If these facilities fail to provide us with adequate transmission capacity, we may be restricted in our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forego revenues. Conversely, improvements to certain transmission systems could also reduce revenues.

We depend on transmission facilities owned and operated by others to deliver the wholesale power we sell from our power generation plants to our customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a region s power transmission infrastructure is inadequate, our 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. We also cannot 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 we operate, energy transmission congestion may occur and we may be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when congestion occurs between the zones. If we are liable for congestion costs, our financial results could be adversely affected.

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

Because we own less than a majority of some of our project investments, we cannot exercise complete control over their operations.

We have limited control over the operation of some project investments and joint ventures because our investments are in projects where we beneficially own less than a majority of the ownership interests. We seek to exert a degree of influence with respect to the management and operation of projects in which we own 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, we may not always succeed in such negotiations. We may be dependent on our co-venturers to operate such projects. Our 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 us to receive distributions of funds from projects or to transfer our interest in projects.

Future acquisition activities may have adverse effects.

We may seek to acquire additional companies or assets in our industry. The acquisition of power generation companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, our 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.

Our operations are subject to hazards customary to the power generation industry. We may not have adequate insurance to cover all of these hazards.

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 our 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 our 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. We maintain an amount of insurance protection that we consider adequate, but we cannot assure you that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, we cannot assure you that insurance coverage will continue to be available at all or at rates or on terms similar to those presently available to us. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows.

Our business is subject to substantial governmental regulation and may be adversely affected by liability under, or any future inability to comply with, existing or future regulations or requirements.

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

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

We are also affected by changes to market rules, tariffs, changes in market structures, changes in administrative fee allocations and changes in market 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, 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 adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets. In addition, the regulatory and legislative changes that have recently been enacted at the federal level and in a number of states in an effort to promote competition are novel and untested in many respects. These new approaches to the sale of electric power have very short operating histories, and it is not yet clear how they will operate in times of market stress or pressure, given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by independent system operators.

Our ownership interest in a nuclear power facility subjects us 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 we indirectly own a 44.0% interest, is subject to regulation by the Nuclear Regulatory Commission, or NRC. Such regulation includes licensing, inspection, enforcement, testing, evaluation and modification of all aspects of nuclear reactor power plant design and operation, environmental and safety performance, technical and financial qualifications, decommissioning funding assurance and transfer and foreign ownership restrictions. Our 44.0% share of the output of STP represents approximately 1,101 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 Business Environmental Matters U.S. Federal Environmental Initiatives Nuclear Waste. Costs associated with these risks could be substantial and have a material adverse effect on our 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 our own plants, third party generators or the ERCOT to cover our then existing forward sale obligations. Such shutdown or modification could also lead to substantial costs related to the storage and disposal of radioactive materials and spent nuclear fuel.

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

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

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

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Environmental laws and regulations have generally become more stringent over time, and we expect this trend to continue. In particular, the U.S. Environmental Protection Agency, or USEPA, has recently promulgated regulations requiring additional reductions in nitrogen oxides, or NO_X and sulfur dioxide, or SO_2, emissions, commencing in 2009 and 2010 respectively, and has also promulgated regulations requiring reductions in mercury emissions from coal-fired electric generating units, commencing in 2010 with more substantial reductions in 2018. These regulatory programs are currently subject to litigation and reconsideration by the USEPA, which could affect the timing of our future capital projects. Moreover, certain of the states in which we operate have promulgated air pollution control regulations which are more stringent than existing and proposed federal regulations. Ongoing public concerns about emissions of SO_2, NO_X, mercury and carbon dioxide and other greenhouse gases from power plants have resulted in proposed laws and regulations at the federal, state and regional levels that, if they were to take effect substantially as proposed, would likely apply to our operations. For example, we could incur substantial costs pursuant to the proposed multi-state carbon cap-and-trade program known as the Regional Greenhouse Gas Initiative, or RGGI, which would apply to the facilities in our Northeast region. A model rule for implementation of RGGI is expected to be released within the next few months.

Significant capital expenditures may be required to keep our facilities compliant with environmental laws and regulations, and if it is not economical to make those capital expenditures then we may need to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

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

The value of our assets is subject to the nature and extent of decommissioning and remediation obligations applicable to us.

Our facilities and related properties may become subject to decommissioning and/or site remediation obligations that may require material unplanned expenditures or otherwise materially affect the value of those assets. The closure or modification of any of our facilities could lead to substantial liabilities, including related to the cleanup of any contamination that occurred during the facility s operation. While we believe that we meet, or are performing, all site remediation obligations currently applicable to our assets (including through the provision of various forms of financial assurance at certain facilities at which we are not currently required to perform remediation), more onerous obligations often apply to sites where a plant is to be dismantled, which could negatively affect our ability to economically undertake power redevelopments or alternate uses at existing power plant sites. Further, laws and regulations may change to impose material additional decommissioning and remediation obligations on us in the future, negatively impacting the value of our assets and/or our ability to undertake redevelopment projects.

Our business, financial condition and results of operations could be adversely impacted by strikes or work stoppages by our unionized employees.

As of December 31, 2005, approximately 46.0% of the Company s employees at its U.S. generation plants would have been covered by collective bargaining agreements. In the event that our union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we would be responsible for procuring replacement labor or we could experience reduced power generation or outages. Our 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 our business, financial condition, results of operations and cash flows.

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Changes in technology may impair the value of our 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 we have currently forecasted, which could adversely affect our revenue, results of operations or competitive position.

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

Our 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 their 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 our financial condition, results of operations and cash flows.

Our international investments are subject to additional risks that our U.S. investments do not have.

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

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

Our plants are the subject of a number of lawsuits filed by individuals who claim injury due to exposure to asbestos while working at certain of our facilities.

Many of our plants have been subject to personal injury claims arising out of alleged exposure to asbestos. Most of the claimants who have brought such claims have been third-party workers who participated in the construction, renovation or repair of various industrial plants, including power plants. While many of the claimants have never worked at or near our plants, some of the claimants have worked at locations owned by us. While we have been dismissed from many of these lawsuits without having to make any payment to claimants, we have incurred and expect to continue to incur costs associated with these claims. We are also subject to claims for asbestos exposure in certain of its facilities, as well as claims for indemnity from previous owners of those facilities. We defend against these claims aggressively, and, thus, we have incurred and expect to continue to incur defense costs as a result of such claims. For further discussion of such claims, see Business Legal Proceedings. If asbestos-related claims against us rise significantly or if insurance currently available for contribution to the payment of asbestos liabilities becomes unavailable (through insurer insolvencies, coverage disputes, changes in law or otherwise), asbestos liabilities could have a material adverse effect on our results of operations, financial condition and cash flows.

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Our level of indebtedness could adversely affect our ability to raise additional capital to fund our operations, expose us to the risk of increased interest rates and limit our ability to react to changes in the economy or our industry.

Our substantial debt could have important consequences, including:

- increasing our vulnerability to general economic and industry conditions;
- requiring a substantial portion of our cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to pay dividends to holders of our preferred or common stock or to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- limiting our ability to enter into long-term power sales or fuel purchases which require credit support;
- exposing us to the risk of increased interest rates because certain of our borrowings, including borrowings under our new senior secured credit facility are at variable rates of interest;
- making it more difficult for us to satisfy our obligations with respect to our notes;
- placing us at a competitive disadvantage compared to our competitors that have less debt;
- limiting our 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 our ability to adjust to changing market conditions and placing us at a competitive disadvantage compared to our competitors who have less debt.

The indentures for the new notes and our new senior secured credit facility contain financial and other restrictive covenants that may limit our ability to engage in activities that may be in our long-term best interests. Our 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 our borrowed indebtedness.

In addition, our 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 us, our partners and the regional wholesale power markets;
- our financial performance and the financial performance of our subsidiaries;
- our levels 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.

We 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 our business and operations.

We may not be able to realize the anticipated benefits from the Texas Genco Acquisition.

The success of the Acquisition will depend in part on NRG s ability to consolidate and effectively integrate the Texas Genco assets, operations and employees into NRG. The integration will require substantial time and attention from our management. If the integration takes longer or is more complex or expensive than anticipated, or if we cannot operate our combined business as effectively as we anticipate, our operating performance and profitability could be materially adversely affected.

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The Texas Genco power generation assets operate in the ERCOT market, a market in which NRG did not operate before the Acquisition. Accordingly, we are dependent upon the managers and employees who were in place at Texas Genco to manage those assets, and the loss of these key managers or employees could adversely affect our business.

In addition, as a result of the Acquisition, we have assumed all of Texas Genco s liabilities. After the Acquisition, we may learn additional information about Texas Genco s business that adversely affects us, such as unknown or contingent liabilities, issues relating to internal controls over financial reporting and issues relating to compliance with applicable laws.

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

NRG s financial statements prior to December 5, 2003 are not comparable to its financial statements after that date. As a result of NRG s emergence from bankruptcy, it is operating its business with a new capital structure, and is subject to Fresh Start reporting requirements prescribed by generally accepted accounting principles in the United States. As required by Fresh Start reporting, assets and liabilities as of December 6, 2003 were recorded at fair value, with the enterprise value being determined in connection with the reorganization.

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

NRG and Texas Genco have been operating as separate companies prior to the Acquisition. We have had no prior history as a combined entity and our operations have not previously been managed on a combined basis. The historical financial statements may not reflect what our results of operations, financial position and cash flows would have been had we operated on a combined basis and may not be indicative of what our results of operations, financial position and cash flows will be in the future.

Goodwill and/or other intangible assets that we will record in connection with the Acquisition are subject to mandatory annual impairment evaluations and as a result, the combined company could be required to write off some or all of this goodwill and other intangibles, which may adversely affect its financial condition and results of operations.

NRG will account for the Acquisition using the purchase method of accounting. The purchase price for Texas Genco will be allocated to identifiable tangible and intangible assets and assumed liabilities based on estimated fair values at the date of consummation of the Acquisition. Any unallocated portion of the purchase price will be allocated to goodwill. In accordance with Financial Accounting Standard No. 142, Goodwill and Other Intangible Assets, goodwill is not amortized but is reviewed annually or more frequently for impairment and other intangibles are also reviewed at least annually or more frequently, if certain conditions exist, and may be amortized. Any reduction in or impairment of the value of goodwill or other intangible assets will result in a charge against earnings which could materially adversely affect our reported results of operations and financial position in future periods.

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Cautionary Statement Regarding Forward Looking Information

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The words believes, projects, anticipates, plans, expects, estimates and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statement. These factors, risks and uncertainties include, but are not limited to, the factors described under Risks Related to NRG Energy, Inc. in this Item 1A and to the following:

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

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

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

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

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

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

The liquidity and competitiveness of wholesale markets for energy commodities;

Changes in government regulation, including but not limited to the pending changes of market rules, market structures and design, rates, tariffs, environmental laws and regulations and regulatory compliance requirements;

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

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

The success of the business following the acquisition of Texas Genco LLC;

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

Lack of comparable financial data due to adoption of Fresh Start reporting.

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

Item 1B ***Unresolved Staff Comments***

None.

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Item 2 *Properties*

Listed below are descriptions of our interests in facilities, operations and/or projects owned as of December 31, 2005, including such interests owned through Texas Genco. The MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the combined company s ownership position excluding capacity from inactive/mothballed units as of December 31, 2005. Prior to the Texas Genco acquisition, our documents referenced the capacity of our generating equipment using Nameplate, or gross capacity (netted to reflect ownership position but inclusive of power which was absorbed internally). The MW numbers included units which are inactive but still owned by NRG. However, with the addition of the Texas assets and to provide a consistent measure across the fleet, NRG will now provide summer net MW capacity for active units only which is more representative of capacity available for sale in the marketplace.

Independent Power Production and Cogeneration Facilities

Name and Location of Facility	Purchaser/Power Market	% Owned	Net Generation Capacity (MW)	Primary Fuel Type
Texas Region:				
W. A. Parish, Thompsons, TX	ERCOT	100.00%	2,463	Low Sulfur Coal
Limestone, Jewett, TX	ERCOT	100.00%	1,614	Lignite/Low Sulfur Coal
South Texas Project, Bay City, TX(1)	ERCOT	44.00%	1,101	Nuclear
Cedar Bayou, TX	ERCOT	100.00%	1,498	Natural Gas
T. H. Wharton, Houston, TX	ERCOT	100.00%	1,025	Natural Gas
W. A. Parish (Natural gas), Thompsons, TX	ERCOT	100.00%	1,191	Natural Gas
S. R. Bertron, Deer Park, TX	ERCOT	100.00%	844	Natural Gas
Greens Bayou, Houston, TX	ERCOT	100.00%	760	Natural Gas
San Jacinto, LaPorte, TX	ERCOT	100.00%	162	Natural Gas
Northeast Region:				
Oswego, New York	NYISO	100.00%	1,634	Oil
Arthur Kill, New York	NYISO	100.00%	841	Natural Gas
Middletown, Connecticut	ISO-NE	100.00%	770	Oil
Indian River, Delaware	PJM	100.00%	737	Coal
Astoria Gas Turbines, New York	NYISO	100.00%	553	Natural Gas
Dunkirk, New York	NYISO	100.00%	522	Coal
Huntley, New York	NYISO	100.00%	552	Coal
Montville, Connecticut	ISO-NE	100.00%	497	Oil
Norwalk Harbor, Connecticut	ISO-NE	100.00%	342	Oil
Devon, Connecticut	ISO-NE	100.00%	124	Natural Gas
Vienna, Maryland	PJM	100.00%	170	Oil
Somerset, Massachusetts	ISO-NE	100.00%	127	Coal
Connecticut Jet Power, Connecticut	ISO-NE	100.00%	104	Oil
Conemaugh, Pennsylvania	PJM	3.72%	64	Coal
Keystone, Pennsylvania	PJM	3.72%	63	Coal

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Name and Location of Facility	Purchaser/Power Market	% Owned	Net Generation Capacity (MW)	Primary Fuel Type
South Central Region:				
Big Cajun II, Louisiana(2)	SERC-Entergy	86.00%	1,489	Coal
Bayou Cove, Louisiana	SERC-Entergy	100.00%	300	Natural Gas
Big Cajun I, Louisiana	SERC-Entergy	100.00%	210	Natural Gas
Big Cajun I, Louisiana	SERC-Entergy	100.00%	220	Natural Gas/Oil
Sterlington, Louisiana	SERC-Entergy	100.00%	176	Natural Gas
Western Region:				
Encina, California	Cal ISO	50.00%	483	Natural Gas
El Segundo Power, California	Cal ISO	50.00%	335	Natural Gas
San Diego Combustion Turbines, California	Cal ISO	50.00%	86	Natural Gas
Saguaro Power Co., Nevada	WECC	50.00%	46	Natural Gas
Chowchilla, California	Cal ISO	100.00%	49	Natural Gas
Red Bluff, California	Cal ISO	100.00%	45	Natural Gas
Other North America Region:				
Audrain(3)	MISO	100.00%	577	Natural Gas
Rockford I, Illinois	PJM	100.00%	310	Natural Gas
Rocky Road Power, Illinois (3)	PJM	50.00%	165	Natural Gas
Rockford II, Illinois	PJM	100.00%	160	Natural Gas
Dover, Delaware	PJM	100.00%	104	Natural Gas/Coal
Power Smith Cogeneration, Oklahoma	SPP	6.25%	7	Natural Gas
Ilion, New York(3)	NYISO	100.00%	58	Natural Gas
James River, Virginia	SERC TVA	50.00%	55	Coal
Cadillac, Michigan(3)	MISO	50.00%	19	Wood
Paxton Creek Cogeneration, Pennsylvania	PJM	100.00%	12	Natural Gas
Australia Region:				
Flinders, South Australia	South Australian Pool	100.00%	700	Coal
Gladstone Power Station, Queensland	Enertrade/Boyne Smelters	37.50%	605	Coal
Other International Region:				
Schkopau Power Station, Germany	Vattenfall Europe	41.90%	400	Coal
MIBRAG mbH, Germany(4)	ENVIA/MIBRAG Mines	50.00%	55	Coal
Itiquira Energetica, Brazil	COPEL	99.20%	156	Hydro

(1) For the nature of our interest and various limitations on our interest, please read Item 1 Business Texas Facilities section.

(2) Units 1 and 2 owned 100%, Unit 3 owned 58%

(3) Committed to sell or may sell or dispose of in 2006

(4) Primarily a coal mining facility

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Thermal Energy Production and Transmission Facilities and Resource Recovery Facilities

Name and Location of Facility	Year of Acquisition	Generating Capacity[1]	% Ownership Interest	Thermal Energy Purchaser/MSW Supplier
NRG Energy Center Minneapolis, MN	1993	Steam: 1,203 mmBtu/hr., (353 MWt) Chilled Water: 41,630 tons (146 MWt)	100%	Approx. 100 steam customers and 47 chilled water customers
NRG Energy Center San Francisco, CA	1999	Steam: 482 mmBtu/Hr. (141 MWt)	100%	Approx. 165 steam customers
NRG Energy Center Harrisburg, PA	2000	Steam: 440 mmBtu/hr. (129 MWt) Chilled water: 2,400 tons (8 MWt)	100%	Approx. 265 steam customers and 3 chilled water customers
NRG Energy Center	1999	Steam: 266 mmBtu/hr. (78 MWt) Chilled water: 12,580 tons (44 MWt)	100%	Approx. 25 steam and 25 chilled water customers
NRG Energy Center San Diego, CA	1997	Chilled water: 7,425 tons (26 MWt)	100%	Approx. 20 chilled water customers
NRG Energy Center St. Paul, MN	1992	Steam: 430 mmBtu/hr. (126 MWt)	100%	Rock-Tenn Company
Camas Power Boiler, Washington	1997	Steam: 200 mm Btu/hr. (59 MWt)	100%	Georgia-Pacific Corp.
NRG Energy Center Dover, DE	2000	Steam: 190 mmBtu/hr. (56 MWt)	100%	Kraft Foods Inc.
NRG Energy Center Oak Park Heights, MN	1992	Steam: 200 mmBtu/Hr. (59 MWt)	100%	Andersen Corp., MN Correctional Facility

(1) Thermal production and transmission capacity is based on 1,000 Btus per pound of steam production or transmission capacity. The unit mmBtu is equal to one million Btus.

Listed below are descriptions of our significant resource recovery assets as of December 31, 2005:

Name and Location of Facility	Date of Acquisition	Processing Capacity[1]	% Ownership Interest	MSW Supplier
Newport, MN[1]	1993	MSW: 1,500 tons/day	100%	Ramsey and Washington Counties
Elk River, MN[2]	2001	MSW: 1,500 tons/day	85%	Anoka, Hennepin and Sherburne Counties; Tri-County Solid Waste Management Commissioner

(1) The Newport facilities are strictly related to garbage-sorting facilities.

(2) For the Elk River facility, NRG s 85% interest is related strictly to garbage-sorting facilities.

Other Properties

In addition, we own various real property and facilities relating to our generation assets, other vacant real property unrelated to our generation assets, interests in other construction projects in various states of completion and properties not used for operational purposes. We believe we have satisfactory title to our plants and facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in our opinion, would not have a material adverse effect on the use or value of our portfolio.

We lease our corporate offices at 211 Carnegie Center, Princeton, New Jersey 08540 and various other office spaces.

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Item 3 Legal Proceedings

California Electricity and Related Litigation

***In re: Wholesale Electricity Antitrust Litigation*, MDL 1405, U.S. District Court, Southern District of California.** The cases included in this proceeding are as follows:

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

NRG Energy is a defendant in all of the above referenced cases. Several of WCP s operating subsidiaries are also defendants in the ***Bustamante*** case. The cases allege unfair competition, market manipulation and price fixing and all seek treble damages, restitution and injunctive relief. In December 2002, the U.S. District Court for the Southern District of California found that federal jurisdiction was absent in the district court, and remanded the cases back to state court. A notice of appeal was filed and on December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the District Court in most respects. On March 5, 2005, the Ninth Circuit denied a petition for rehearing and thereafter remanded the cases to San Diego Superior Court. NRG was dismissed on July 22, 2005. The remaining defendants including the WCP subsidiaries filed a motion to dismiss based on the filed rate doctrine and federal preemption which was granted on October 3, 2005. Although a judgment of dismissal with prejudice was entered on October 5, 2005, the Plaintiffs filed a notice of appeal on December 2, 2005, with the U.S. Court of Appeals for the Ninth Circuit. Where WCP or its subsidiaries are named, Dynegy is defending the named parties pursuant to an indemnification agreement.

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

***Jerry Egger, et al. v. Dynegy, Inc., et al.*, Case No. 809822, Superior Court of California, San Diego County** (filed May 1, 2003). This putative class action alleges violations of California s antitrust law, as well as unlawful and unfair business practices and seeks treble damages, restitution and injunctive relief. The named defendants include WCP and several of its operating subsidiaries. NRG Energy is not named. This case was removed to the U.S. District Court for the Northern District of California, and the defendants have moved to have this case included as Multi-District Litigation along with the above referenced cases. On February 19, 2004, the court stayed the case. Dynegy s counsel is defending Dynegy and WCP and its subsidiaries in this case pursuant to an indemnification agreement. The defendants expect to seek dismissal of this case during 2006.

***Texas-Ohio Energy, Inc., on behalf of Itself and all others similarly situated v. Dynegy, Inc. Holding Co., West Coast Power, LLC, et al.*, Case No. CIV.S-03-2346 DFL GGH, U.S. District Court, Eastern District of California**(filed November 10, 2003). This putative class action alleges violations of the federal Sherman and

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Clayton Acts and state antitrust law. In addition to naming WCP and Dynegy, Inc. Holding Co., the complaint names numerous industry participants, as well as unnamed co-conspirators. The complaint alleges that defendants conspired to manipulate the spot price and basis differential of natural gas with respect to the California market. The complaint seeks unspecified amounts of damages, including a trebling of plaintiff s and the putative class s actual damages. On April 18, 2005, the court granted defendants motion to dismiss based on the filed rate doctrine and federal preemption. On May 17, 2005, Plaintiffs filed a notice of appeal with the U.S. Court of Appeals for the Ninth Circuit. Dynegy is defending WCP pursuant to an indemnification agreement.

City of Tacoma, Department of Public Utilities, Light Division, v. American Electric Power Service Corporation, et al., **U.S. District Court, Western District of Washington, Case No. C04-5325 RBL** (filed June 16, 2004). The complaint names over 50 defendants, including WCP s four operating subsidiaries and various Dynegy entities. The complaint also names both us and WCP as Non-Defendant Co-Conspirators. Plaintiff alleges a conspiracy to violate the federal Sherman Act by withholding power generation from, and/or inflating the apparent demand for power in markets in California and elsewhere. Plaintiff claims damages in excess of $175 million. After the case was transferred to the U.S. District Court for the Southern District of California on February 11, 2005, the court granted defendants motion to dismiss the case based on the filed rate doctrine and federal preemption. On March 21, 2005, Plaintiffs filed a notice of appeal with the U.S. Court of Appeals for the Ninth Circuit. Dynegy is defending WCP and its subsidiaries pursuant to an indemnification agreement.

Fairhaven Power Company v. Encana Corporation, et al., **Case No. CIV-F-04-6256 (OWW/ LJO), U.S. District Court, Eastern District of California**(filed September 22, 2004), ***Abelman v. Encana, U.S.*** **District Court, Eastern District of California, Case No. 04-CV-6684** (filed December 13, 2004); ***Utility Savings v. Reliant, et al.,*** **U.S. District Court, Eastern District of California,** (filed November 29, 2004). These putative class actions named WCP and Dynegy Holding Co., Inc. among the numerous defendants. The Complaints alleged violations of the federal Sherman Act, and California s antitrust and unfair competition law as well as unjust enrichment. The Complaints sought a determination of class action status, a trebling of unspecified damages, statutory, punitive or exemplary damages, restitution, disgorgement, injunctive relief, a constructive trust, and costs and attorneys fees. On December 19, 2005, the court granted defendants notice to dismiss based upon the filed rate doctrine and federal preemption. Dynegy is defending WCP pursuant to an indemnification agreement. On February 2, 2006, Dynegy settled the case on behalf of itself and WCP. A motion for approval of this settlement is expected to be filed by the plaintiffs by March 30, 2006.

In Re: Natural Gas Commodity Litigation, **Master File No. 03 CV 6186(VM)(AJP), U.S. District Court, Southern District of New York.** West Coast Power, or WCP, and Dynegy Marketing and Trade are among numerous defendants accused of manipulating gas index publications and prices in violation of the federal Commodity Exchange Act, or CEA, in the following consolidated cases: ***Cornerstone Propane Partners, LP v. Reliant Energy Services, Inc., et al.***, **Case No. 03 CV 6186** (S.D.N.Y. filed August 18, 2003); ***Calle Gracey v. American Electric Power Co., Inc., et al.***, **Case No. 03 CV 7750** (S.D.N.Y. filed Oct. 1, 2003); ***Cornerstone Propane Partners, LP v. Coral Energy Resources, LP, et al.***, **Case No. 03 CV 8320** (S.D.N.Y. filed Oct. 21, 2003); and ***Viola v. Reliant Energy Servs., et al.***, **Case No. 03 CV 9039** (S.D.N.Y. filed Nov. 14, 2003). Plaintiffs, in their Amended Consolidated Class Action Complaint dated October 14, 2004, allege that the defendants engaged in a scheme to manipulate and inflate natural gas prices. The plaintiffs seek class action status for their lawsuit, unspecified actual damages for violations of the CEA and costs and attorneys fees. On September 30, 2005, the court granted Plaintiffs class action certification. On November 2, 2005, Dynegy entered into a settlement agreement with Plaintiffs that also resolves claims against the WCP subsidiaries. The settlement is awaiting court approval. Dynegy Marketing and Trade is defending WCP in these proceedings pursuant to an indemnification agreement.

ABAG Publicly Owned Energy Resources v. Sempra Energy, et al., **Alameda County Superior Court, Case No. RG04186098,** filed November 10, 2004; ***Cruz Bustamante v. Williams Energy Services, et al.,*** **Los Angeles Superior Court, Case No. BC285598,** filed June 28, 2004; ***City & County of San Francisco, et al. v. Sempra Energy, et al.***, **San Diego County Superior Court, Case No. GIC832539,** filed June 8, 2004; ***City of San Diego v. Sempra Energy, et al.,*** **San Diego County Superior Court, Case No. GIC839407,** filed

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

The defendants in all of the above referenced cases include WCP and various Dynegy entities. NRG is not a defendant. The Complaints allege that defendants attempted to manipulate natural gas prices in California, and allege violations of California s antitrust law, conspiracy, and unjust enrichment. The relief sought in all of these cases includes treble damages, restitution and injunctive relief. The Complaints assert that WCP is a joint venture between Dynegy and NRG, but that Dynegy Marketing and Trade handled all of the administrative services and commodity related concerns of WCP. The cases are presently being consolidated for coordinated pretrial proceedings in San Diego County Superior Court. Defendants motion to dismiss was denied by the Court on June 22, 2005, and the cases are in discovery. Dynegy is defending WCP pursuant to an indemnification agreement.

California Electricity and Related Litigation Indemnification

On December 27, 2005, NRG entered into a purchase and sale agreement to acquire Dynegy s 50% ownership interest in WCP Holdings to become the sole owner of the WCP power plants. The transaction, which is subject to regulatory approval, is expected to close in the first quarter of 2006. Pursuant to the indemnification agreement in the purchase and sale agreement, in the above referenced cases relating to natural gas, Dynegy is defending WCP and/or its subsidiaries and will be the responsible party for any loss. In the above referenced cases relating to electricity, Dynegy s counsel is representing it and WCP and/or its subsidiaries with Dynegy and WCP each responsible for half of the costs and each party responsible for half of any loss. Where NRG is named as a party in the above referenced electricity cases, it is defending the case, bears its own costs of defense, and is responsible for any loss. Any new cases filed within these three categories of cases would be handled similarly.

NRG Bankruptcy Cap on California Claims

On November 21, 2003, in conjunction with confirmation of the NRG plan of reorganization, we reached an agreement with the Attorney General and the State of California, generally, whereby for purposes of distributions, if any, to be made to the State of California under the NRG plan of reorganization, the liquidated amount of any and all allowed claims shall not exceed $1.35 billion in the aggregate. The agreement neither affects our right to object to these claims on any and all grounds nor admits any liability whatsoever. We further agreed to waive any objection to the liquidation of these claims in a non-bankruptcy forum having proper jurisdiction. On February 1, 2006, NRG filed with the U.S. Bankruptcy Court for the Southern District of New York a Supplement to Objection to Claims filed by Oscars Photolab, claiming on behalf of Itself and All Other Similarly Stated California Business and Residential Ratepayers. Therein, NRG requested an order disallowing and expunging these proofs of claim.

FERC Proceedings

There are a number of proceedings in which WCP subsidiaries are parties, which are either pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the California Independent System Operator, or CDWR, and the State of California and certain of its agencies and departments. The CDWR claim involves a February 2002 complaint filed by the State of California demanding that FERC abrogate the CDWR contract between the State and subsidiaries of WCP and seeking refunds associated with the revenues collected by WCP from the CDWR. In 2003, FERC rejected the States complaint and subsequently denied rehearing. The State appealed to the U.S. Court of Appeals for the Ninth Circuit where all briefs were filed and oral argument was held on December 8, 2004. Pursuant to the December 27, 2005 purchase and sale agreement between NRG and Dynegy regarding the WCP power plants, we agreed to indemnify Dynegy with respect to the CDWR claim. However, to the effect any loss incurred is found to have resulted from Dynegy s gross negligence or willful misconduct, then any such loss shall instead be shared evenly between Dynegy and us. The purchase and sale agreement is subject to regulatory approval and is expected to close in the first quarter of 2006.

***Consolidated Edison Co. of New York v. Federal Energy Regulatory Commission*, Docket No. 01-1503.** Consolidated Edison and others petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of certain FERC orders in which FERC refused to order a re-determination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for the period January 29, 2000, to March 27, 2000. On November 7, 2003, the Court issued a decision which questioned whether that the NYISO s method of pricing spinning reserves violated the NYISO tariff. The Court also required FERC to determine whether the exclusion from the non-spinning market of a generating facility known as Blenheim-Gilboa and resources located in western New York also constituted a tariff violation and/or whether these exclusions enabled NYISO to use its Temporary Extraordinary Procedure, or TEP, authority to require refunds. On March 4, 2005, FERC issued an order stating that no refunds would be required for the tariff violation associated with the pricing of spinning reserves. In the order, FERC also stated that the exclusion of the Blenheim-Gilboa facility and western reserves from the non-spinning market was not a market flaw and NYISO was correct not to use its TEP authority to revise the prices in this market. A motion for rehearing of the Order was denied by FERC on November 17, 2005. On January 13, 2006, the petitioners filed an appeal with the U.S. Court of Appeals for the District of Columbia Circuit. Based on the November 17, 2005 denial, we now deem the risk of loss to be remote.

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

***Connecticut Light & Power Company v. NRG Energy, Inc.,* Federal Energy Regulatory Commission Docket No. EL03-10-000-Station Service Dispute** (filed October 9, 2002); **Binding Arbitration.** On July 1, 1999, Connecticut Light & Power Company, or CL&P, and the Company agreed that we would purchase certain CL&P generating facilities. The transaction closed on December 14, 1999, whereupon NRG Energy took ownership of the facilities. CL&P began billing NRG Energy for station service power and delivery services provided to the facilities and NRG Energy refused to pay asserting that the facilities self-supplied their station service needs. On October 9, 2002, Northeast Utilities Services Company, on behalf of itself and CL&P, filed a complaint at FERC seeking an order requiring NRG Energy to pay for station service and delivery services. On December 20, 2002, FERC issued an Order finding that at times when NRG Energy is

not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. CL&P renewed its demand for payment which was again refused by NRG Energy. In August 2003, the parties agreed to submit the dispute to binding arbitration. The parties each selected one respective arbitrator. A neutral arbitrator cannot be selected until the party-appointed arbitrators have been given a mutually agreed upon description of the dispute, which has yet to occur. Once the neutral arbitrator is selected, a decision is required within 90 days unless otherwise agreed by the parties. The potential loss inclusive of amounts paid to CL&P and accrued could exceed $5 million.

***New York Public Interest Research Group (NYPIRG) v. Stephen L. Johnson, Administrator, U.S. Environmental Protection Agency*, Case Nos.03-40846(L) and 03-40848 (CON), U.S. Court of Appeals for the Second Circuit.** In 2000, the New York State Department of Environmental Conservation, or NYSDEC, issued a NOV to the prior owner of the Huntley and Dunkirk stations. After an unsuccessful challenge to the stations Title V air quality permits by NYPIRG, it appealed. On October 24, 2005, the Second Circuit held that, during the Title V permitting process for the two stations, the 2000 NOV should have been sufficient for the NYSDEC to have made a finding that the stations were out of compliance. Accordingly, the court stated that the EPA should have objected to the Title V permits on that basis and the permits should have included compliance schedules. On June 3, 2005, the consent decree among NYSDEC, Niagara Mohawk Power Corporation and NRG was entered in federal court, settling the substantive issues discussed by the Second Circuit in its decision. NYSDEC is in the process of incorporating the consent decree obligations into the Huntley and Dunkirk Title V permits so as to make them permit conditions, an action we believe is supported by the decision. On January 12, 2006, the NYSDEC, the EPA, and NRG filed individual petitions for rehearing with the Second Circuit. On January 31, 2006, the court denied the petitions for re-hearing filed by the NYSDEC and the EPA. NRG s petition for review en banc remains pending.

***Niagara Mohawk Power Corporation v. Dunkirk Power LLC, NRG Dunkirk Operations, Inc., Huntley Power LLC, NRG Huntley Operations, Inc., Oswego Power LLC and NRG Oswego Operations, Inc.*, Supreme Court, Erie County, Index No. 1-2000-8681 Station Service Dispute** (filed October 2, 2000). NiMo sought to recover damages less payments received through the date of judgment, as well as additional amounts for electric service provided to the Dunkirk Plant. NiMo claimed that we failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999, and continuing to September 18, 2000, and thereafter. NiMo alleged breach of contract, suit on account, violation of statutory duty, and unjust enrichment claims. On October 8, 2002, a Stipulation and Order was entered staying this action pending resolution by FERC of some or all of the disputes in the action. The potential loss inclusive of amounts paid to NiMo and accrued is approximately $26 million.

***Niagara Mohawk Power Corporation v. Huntley Power LLC, NRG Huntley Operations, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power LLC, Oswego Harbor Power LLC, and NRG Oswego Operations, Inc.*, Case Filed November 26, 2002 in Federal Energy Regulatory Commission Docket No. EL 03-27-000.** This is the companion action to the above referenced action filed by NiMo at FERC asserting the same claims and legal theories. On November 19, 2004, FERC denied NiMo s petition and ruled that the Huntley, Dunkirk and Oswego plants could net their service station obligations over a 30 calendar day period from the day NRG Energy acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. On April 22, 2005, FERC denied NiMo s motion for rehearing and NiMo appealed to the U.S. Court of Appeals for the District of Columbia Circuit . On May 12, 2005, the court consolidated the appeal with several pending station service disputes involving NiMo.

Itiquira Energetica, S.A. Our Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes, or Inepar . The dispute was commenced by Itiquira in September of 2002 and pertains to certain matters arising under the former engineering procurement and construction contract between the parties. Itiquira sought Real 140 million and asserted that Inepar breached the contract. Inepar sought Real 39 million and alleged that Itiquira breached the contract. On September 2, 2005, the arbitration panel ruled in favor of Itiquira, awarding it Real 139 million and Inepar Real 4.7 million. Due to interest accrued from the commencement of the arbitration to the award date, Itiquira s award is increased to

approximately Real 227 million (U.S. $97 million, based on conversion rates as of December 31, 2005). On December 21, 2005, Inepar s request for clarification of the arbitration panels decision was denied. Itiquira has commenced the lengthy process in Brazil to execute on the arbitral award. We are unable to predict the outcome of this execution process.

CFTC Trading Inquiry. On July 1, 2004, the CFTC filed a civil complaint against us in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act. On July 23, 2004, we filed a motion with the bankruptcy court to enforce the injunction provisions of the NRG plan of reorganization against the CFTC. Thereafter, we filed with the Minnesota federal district court a motion to dismiss. On November 17, 2004, a Bankruptcy Court hearing was held on the CFTC s motion to reinstate its expunged bankruptcy claim, and on our motion to enforce the injunction contained in our plan of reorganization in order to preclude the CFTC from continuing its Minnesota federal court action. On March 16, 2005, the federal district court in Minnesota adopted the magistrate judge s December 6, 2004, report and recommendations and dismissed the case. On May 13, 2005, the CFTC filed a notice of appeal with the U.S. Court of Appeals for the Eighth Circuit and its brief on August 9, 2005. On September 29, 2005, NRG replied and on October 28, 2005, the CFTC filed its reply brief. The parties are awaiting an argument date. The Bankruptcy Court has yet to schedule a hearing or rule on the CFTC s pending motion to reinstate its expunged claim.

Texas Commercial Energy v. TXU Energy, Inc. et al., **Case No. 04-40962 U.S. District Court for the Southern District of Texas Corpus Christi Division.** This lawsuit was filed against us, CenterPoint Energy, Inc., Reliant Energy, Inc., Reliant Electric Solutions, LLC, several other CenterPoint Energy and Reliant Energy subsidiaries, and a number of other participants in the ERCOT market. The plaintiff, a retail electricity provider in the Texas market served by ERCOT, alleged that the defendants conspired to illegally fix and artificially increase the price of electricity in violation of state and federal antitrust laws and committed fraud and negligent misrepresentation. The lawsuit sought damages in excess of $500 million, exemplary damages, treble damages, interest, costs of suit and attorneys fees. In June 2004, the court dismissed plaintiff s claims on jurisdictional grounds. In July , 2004, the plaintiff filed an appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit affirmed the lower court s decision in June 2005. The plaintiff moved for a rehearing en banc which was subsequently denied. On January 9, 2006, the U.S. Supreme Court denied plaintiff s petition for certiorari thereby ending recourse.

Asbestos Litigation. Several of our plants are the subject of a number of lawsuits filed against numerous defendants by a large number of individuals who claim personal injury due to alleged exposure to asbestos while working at plant sites primarily in Texas. The overwhelming majority of these claimants are third party contractor or sub-contractors who participated in the construction, renovation, or repair of various industrial plants, including power plants. As of December 31, 2005, there were 3,803 claims pending in Texas. For the twelve months ended December 31, 2005, there were 268 claims filed, 146 claims settled, 1,261 claims dismissed or otherwise resolved with no payment, and the average settlement amount was approximately $3,600. While ultimate financial responsibility for uninsured losses relating to asbestos claims has been assumed by us, CenterPoint Energy has agreed to continue to defend such claims to the extent they are covered by insurance maintained by CenterPoint Energy, subject to reimbursement of the costs of such defense from us. To date, costs of settlement and defense have not been material and a portion of the payments in respect of these claims have been offset by insurance recoveries.

On May 19, 2005, amendments to the Texas Civil Practice and Remedies Code and other state codes were signed into law by the Governor of Texas. The law will make it more difficult for persons claiming personal injuries due to alleged exposure to asbestos to continue to pursue their claims when there is no medical evidence of an actual physical impairment caused by exposure to asbestos. The law precludes persons whose claims have not been adjudicated by September 1, 2005, from pursuing or advancing their claims until they have produced a report by a board-certified physician of an actual physical impairment caused by exposure to asbestos. In addition, Congress is currently considering the proposed Fairness in Asbestos Injury Resolution Act of 2005, which, if it becomes law, would require asbestos defendants and insurers to make payments into a privately-funded national asbestos compensation fund. Under the bill as currently drafted, any payments made by us would not be offset by any insurance recoveries.

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Additional Litigation

In addition to the foregoing, we are parties to other litigation or legal proceedings. See Market Developments in the various regions in Item 1 Business Power Generation for additional discussion on regulatory legal proceedings.

The Company believes that it has valid defenses to the legal proceedings and investigations described above and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified above, the Company is unable to predict the outcome these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company s consolidated financial position, results of operations or cash flows. The Company also has indemnity rights for some of these proceedings to reimburse the Company for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

Disputed Claims Reserve

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

The face amount of the remaining unresolved claims is approximately $35 million, plus unresolved claims relating to the California power crisis in 2000-2001 and other claims of indefinite amount, but the Company estimates that the actual amount of these claims, once settled, will be less than $35 million. Based on these estimates, the Company believes that in order to assure sufficient funds to satisfy all remaining disputed claims the reserve needs to retain approximately $7 million in cash and approximately 650,000 shares of common stock. The reserve currently holds cash and stock in excess of these amounts, and the Company intends to make a supplemental distribution of the surplus on or about April 1, 2006. The total value of the planned distribution is approximately $137 million, based on the closing stock price on March 3, 2006, consisting of approximately $25 million in cash and 2,541,000 shares of NRG common stock. NRG s chapter 11 creditors holding allowed claims in Class 5 are expected to receive approximately $22.13 per $1,000.00 of allowed claim, consisting of $4.05 in cash and 0.41 shares of NRG common stock. Creditors holding Class 6 allowed claims are expected to receive approximately $19.97 per $1,000.00 of allowed claim, consisting of $1.89 in cash and 0.41 shares of NRG common stock.

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

None.

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PART II

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

Market Information and Holders

In connection with the consummation of our reorganization, on December 5, 2003, all shares of our old common stock were canceled and 100,000,000 shares of new common stock of NRG were distributed pursuant to such plan in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. See Item 3 Legal Proceedings Disputed Claims Reserve. In the event our disputed claims reserve is inadequate, it is possible we will have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. Our authorized capital stock consists of 500,000,000 shares of NRG common stock and 10,000,000 shares of preferred stock. A total of 4,000,000 shares of our common stock are available for issuance under our long-term incentive plan. We have also filed with the Secretary of State of Delaware a Certificate of Designation for each of the following shares of preferred stock: (i) our 4% Convertible Perpetual Preferred Stock: (ii) our 3.625% Convertible Perpetual Preferred Stock and (iii) our 5.75% Mandatory Convertible Preferred Stock. We also issued 35,406,292 shares of our common stock in connection with the Texas Genco Acquisition as described below. Also in connection with the Texas Genco Acquisition we issued 20,855,057 shares of common stock in a public offering; 2,000,000 shares of our 5.75% Mandatory Convertible Preferred Stock in a public offering; and $3.6 billion of unsecured high yield notes.

Our common stock is listed on the New York Stock Exchange and has been assigned the symbol: NRG. We have submitted to the New York Stock Exchange our annual certificate from our Chief Executive Officer certifying that he is not aware of any violation by us of New York Stock Exchange corporate governance listing standards. The high and low sales prices, as well as the closing price for our common stock on a per share basis for 2005 and 2004 are set forth below:

Common Stock Price	Fourth Quarter 2005	Third Quarter 2005	Second Quarter 2005	First Quarter 2005	Fourth Quarter 2004	Third Quarter 2004	Second Quarter 2004	First Quarter 2004
High	$ 49.44	$ 44.45	$ 37.61	$ 39.10	$ 36.18	$ 28.43	$ 24.80	$ 22.50
Low	$ 37.60	$ 36.40	$ 30.30	$ 32.79	$ 26.00	$ 24.10	$ 19.17	$ 18.10
Closing	$ 47.12	$ 42.60	$ 30.70	$ 34.15	$ 36.05	$ 26.94	$ 24.80	$ 22.20

NRG had 80,701,888 shares outstanding as of December 31, 2005, and as of March 3, 2006, there were 136,975,275 shares outstanding. As of February 10, 2006, there were approximately 27,000 common stockholders of record.

Dividends

We have not declared or paid dividends on our common stock and the amount available for dividends is currently limited by our senior secured credit agreements and high yield note indentures.

Recent Sale of Unregistered Securities; Repurchase of Common Stock

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

On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement with Credit Suisse First Boston, or CSFB, pursuant to which we repurchased $250 million of our common stock on that date that equaled a total of 6,346,788 shares, which were held in treasury. We funded the repurchase with cash on hand. On March 3, 2006, we paid to CSFB a cash purchase price adjustment of approximately $7 million based upon the weighted average value of NRG s common stock over a period of approximately six months, subject to a minimum price of 97% and a maximum price of 103% of the closing price per share on August 10, 2005, or $39.39.

The following table summarizes the stock repurchased by NRG Energy:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares That May Yet be Purchased Under the Plans
August 11, 2005	6,346,788*	$ 39.90	none	N/A

* 6,346,788 shares were purchased as part of the Accelerated Share Repurchase Agreement with CSFB as described above.

Redemption and Repurchase of Second Priority Notes

During 2005 we redeemed and repurchased approximately $645 million of our Second Priority Notes in a number of stages as described in the following table:

Date of Redemption or Repurchase	Amount	Source
January 2005	$25 million face value repurchased	Existing cash
February 2005	$375 million redeemed	Proceeds from the sale of the 4% Preferred Stock in December 2004
March 2005	$15.8 million face value repurchased	Existing Cash
September 2005	$229 million redeemed	Proceeds from the sale of the 3.625% Preferred Stock in August 2005

As of December 31, 2005, the outstanding balance of our Second Priority Notes was approximately $1.1 billion. All outstanding Second Priority Notes were tendered, paid off and defeased on February 2-3, 2006, using funds received from a number of financial transactions as described in Item 15 Note 34 to the Consolidated Financial Statements.

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Securities Authorized for Issuance Under Equity Compensation Plans

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	2,593,179	$ 25.04	1,355,193*
Equity compensation plans not approved by security holders		n/a	
Total	2,593,179	$ 25.04	1,355,193*

* The NRG Energy, Inc. Long-Term Incentive Plan became effective upon our emergence from bankruptcy. The Long-Term Incentive Plan, which was adopted in connection with the NRG plan of reorganization, was approved by our stockholders on August 4, 2004. The Long-Term Incentive Plan provides for grants of stock options, stock appreciation rights, restricted stock, performance awards, deferred stock units and dividend equivalent rights. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by us, are eligible to receive grants under the Long-Term Incentive Plan. A total of 4,000,000 shares of our common stock are available for issuance under the Long-Term Incentive Plan. The purpose of the Long-Term Incentive Plan is to promote our long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility. The Compensation Committee of our Board of Directors administers the Long-Term Incentive Plan. There were 1,355,193 and 2,053,294 shares of common stock remaining available for grants of stock options under our Long-Term Incentive Plan as of December 31, 2005 and 2004, respectively.

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Item 6 ***Selected Financial Data***

The following table presents our historical selected financial data. The data included in the following table has been restated to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations. For additional information refer to Item 15 Note 6 to the Consolidated Financial Statements. The historical financial data does not reflect any amounts for the purchase of Texas Genco as the Acquisition closed after December 31, 2005.

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

	Reorganized NRG			Predecessor Company		
	Year Ended December 31,		December 6 - December 31,	January 1 - December 5,	Year Ended December 31,	
	2005	2004	2003	2003	2002	2001
	(In millions, except per share amounts)					
Revenues from majority-owned operations	$ 2,708	$ 2,348	$ 137	$ 1,798	$ 1,926	$ 2,085
Corporate relocation charges	6	16				
Reorganization, restructuring and impairment charges	6	32	2	435	2,497	
Fresh start reporting adjustments				(4,220)		
Legal settlement				463		
Total operating costs and expenses	2,470	1,955	122	(1,587)	4,231	1,704
Write downs and losses on equity method investments	(31)	(16)		(147)	(200)	
Income/(loss) from continuing operations	77	161	11	3,082	(2,693)	211
Income/(loss) from discontinued operations, net	7	25		(316)	(771)	55
Net income/(loss)	84	186	11	2,766	(3,464)	265
Income/(loss) from continuing operations per weighted average share basic	$ 0.67	$ 1.61	$ 0.11			

Income/(loss) from continuing operations per weighted average share diluted	$	0.66	$	1.60	$	0.11				
Total assets		7,431		7,864		9,315	N/A		10,897		12,915
Long-term debt, including current maturities	$	2,682	$	3,484	$	3,846	N/A	$	7,217	$	6,291

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The following table provides the detail of our revenues from majority-owned operations:

	Reorganized NRG			Predecessor Company		
	Year Ended December 31,		December 6 - December 31,	January 1 - December 5,	Year Ended December 31,	
	2005	2004	2003	2003	2002	2001
	(In millions)					
Energy	$ 2,014	$ 1,364	$ 64	$ 910	$ 1,172	$ 1,376
Capacity	563	612	37	566	553	490
Hedging and risk management activities	(248)	76	2	19	7	
Alternative energy	191	176	12	82	98	162
O&M fees	20	21	1	13	14	16
Other	168	99	21	208	82	41
Total revenues from majority-owned operations	$ 2,708	$ 2,348	$ 137	$ 1,798	$ 1,926	$ 2,085

Energy revenue consists of revenues received from third parties for sales in the day-ahead and real-time markets, as well as bilateral sales. In addition, this category includes day-ahead and real-time operating revenues.

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

Hedging and Risk management activities includes fair value changes of financial instruments (derivatives) that have yet to be settled for the period, as well as, the revenues derived from the settlement of financial transactions relating to the sale of energy or fuel which do not require the physical delivery of the underlying commodity.

Alternative energy 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. Alternative energy revenue includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process. In addition, alternative revenue includes revenues received from the processing of municipal solid waste into refuse derived fuel that is sold to a third party to be used as fuel in the generation of electricity.

Operations and management, or O&M, fees consist primarily of revenues received from providing certain unconsolidated affiliates with management and operational services generally under long-term operating agreements.

Other revenues consist of miscellaneous other revenues derived from the sale of natural gas, recovery of incurred costs under reliability agreements and revenues received under leasing arrangements. In addition, we also generate revenues from maintenance, the sale of ancillary services excluding day-ahead. Ancillary revenues are derived from the sale of energy related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products.

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

Introduction and Overview

NRG Energy, Inc., or NRG Energy , the Company , we , our , or us is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. As of the close of the Acquisition, our principal domestic generation assets consist of a diversified mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 45%, 34%, 16% and 5% of our total domestic generation capacity, respectively. In addition, 10% of our domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option.

In this discussion and analysis, we will discuss and explain the general financial condition and the results of operations for NRG during 2005 that will include the points below:

- Factors which affect our business,
- Our earnings and costs in the periods presented,
- Changes in earnings and costs between periods,
- Sources of earnings,
- Impact of these factors on our overall financial condition,
- A discussion of known trends, including the expected impact of the Texas Genco Acquisition, that will affect our 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 our Consolidated Statements of Income, which present the results of our operations for the years ended December 31, 2005 and 2004, the period of December 6, 2003 through December 31, 2003 and for the period of January 1, 2003 through December 5, 2003. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income. However, it is important to note that the historical financial information does not include any results of operation or the financial condition of Texas Genco.

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- We then describe the business environment in which we operate including how regulation, weather, and other factors affect our business.
- We highlight significant events that are important to understanding our results of operations and financial condition.
- We then review our results of operations discussing:
  - An overview of our total company results, followed by a more detailed review of those results by operating segment.
  - Known trends that will affect our results of operations in the future.

We review our financial condition addressing:

- Our sources and uses of cash, credit ratings, capital resources and requirements, commitments, and off-balance sheet arrangements.

- Known trends that will affect our financial condition in the future.

Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results of operations and require management s most difficult, subjective or complex judgment.

Our Strategy

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

Increase value from our existing assets. We have a highly diversified portfolio of power generation assets in terms of region, fuel type and dispatch levels. We will continue to focus on extracting value from our portfolio by improving plant performance, reducing costs and harnessing our advantages of scale in the procurement of fuels: a strategy that we have branded *FOR*NRG, or Focus on ROIC@NRG.

Pursue intrinsic growth opportunities at existing sites in our core regions. We are favorably positioned to pursue growth opportunities through expansion of our existing generating capacity. We intend to invest in our existing assets through plant improvements, repowering and brownfield development to meet anticipated regional requirements for new capacity. We expect that these efforts will provide more efficient energy, lower our delivered cost, expand our electricity production capability and improve our ability to dispatch economically across all sections of the merit order, including baseload, intermediate and peaking generation.

Maintain financial strength and flexibility. We remain focused on increasing cash flow and maintaining liquidity and balance sheet strength in order to ensure continued access to capital for growth; enhancing risk-adjusted returns; and providing flexibility in executing our business strategy. We will continue our focus on maintaining operational and financial controls designed to ensure that our financial position remains strong.

Reduce the volatility of our cash flows through asset-based commodity hedging activities. We will continue to execute asset-based risk management, hedging, marketing and trading strategies within well-defined risk and liquidity guidelines in order to manage the value of our physical and contractual assets. Our marketing and hedging philosophy is centered on generating stable returns from our portfolio of power generation assets while preserving the ability to capitalize on strong spot market conditions and to capture the extrinsic value of our portfolio. We believe that we can successfully execute this strategy by taking advantage of our expertise in marketing power and ancillary services, our knowledge of markets, our flexible financial structure and our diverse portfolio of power generation assets.

Participate in continued industry consolidation. We will continue to pursue selective acquisitions, joint ventures and divestitures to enhance our asset mix and competitive position in our core regions to meet the fuel and dispatch requirements in these regions. We intend to concentrate on acquisition and joint venture opportunities that present attractive risk-adjusted returns. We will also opportunistically pursue other strategic transactions, including mergers, acquisitions or divestitures during the consolidation of the power generation industry in the United States.

Business Environment

General Industry This past year, the energy and power sector has been shaken by significant events and change. These have shifted the industry s focus toward more efficient energy and fuel management, infrastructure developmental needs, and scope and scale merits. Those events include:

Hurricanes Katrina and Rita exacerbated an already tight national natural gas production and delivery system during record summer demand. This led to significant price spikes and volatility across all fuel sources, which in turn spurred regulatory concerns over excessive burdens on retail consumers and

renewed interest by incumbent utilities in securing long-term power supplies that are not tied to the price of natural gas.

The Energy Policy Act of 2005, or EPAct, the most comprehensive energy legislation in more than a decade, was enacted in August 2005. EPAct reinforces FERC oversight and monitoring responsibilities and encourages the development of regulatory framework that provide the appropriate market signals for increased infrastructure investment including generation.

While financial and strategic buyers continue to participate in energy sector asset sales and acquisitions, there has been renewed interest within the power sector for scope and scale and renewed merger and acquisitions activities by existing owners of power generation. This year has also seen regulated utilities seeking to participate in the competitive markets through outright combinations with deregulated entities.

The EPA released its CAIR and CAMR guidelines in March. While there continues to be uncertainty as to the implementation standards by certain states, these environmental requirements coupled with potential improved scrubber technologies provide additional clarity with respect to longer term compliance strategies that will drive higher capital expenditure programs towards the end of the decade for many energy providers.

There has been contentious but continued progress towards capacity markets evolution in order to meet increasing demand and encourage new investment in transmission and generation in load pockets around the country, including New England and California.

Competition Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. We compete on the basis of the location of our plants and owning multiple plants in our regions, which increases the stability and reliability of our energy supply. Wholesale power generation is fundamentally a local business which, at present, is 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 we compete against from market to market.

Regulatory Matters As an operator of power plants and a participant in wholesale energy markets, we are subject to regulation by various federal and state government agencies. These include FERC, NRC, PUCT and certain state public utility commissions in which our generating assets are located. In addition, we are also subject to the market rules, procedures and protocols of the various ISO markets in which we participate. The plant operations of, and wholesale electric sales from our Texas assets are not currently subject to regulation by FERC, as they are deemed to operate solely within the ERCOT and not in interstate commerce. These operations are subject to regulations by PUCT as well as to regulation by the NRC with respect to its ownership interest in the STP.

Weather Weather conditions in the different regions of the United States influence the financial results of our business. Weather conditions can affect the supply of and demand for electricity and fuels. Changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market, which may affect our results in any given period. Typically, demand for electricity and its price are higher in the summer and the winter, 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 we are not typically exposed to the effects of extreme weather in all parts of our 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 our 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 our generating facilities relative to the location of our load-serving opportunities,

procedures used to maintain the integrity of the physical electricity system during extreme conditions, and

changes in the nature and extent of federal and state regulations

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

weather conditions,

market liquidity,

capability and reliability of the physical electricity and gas systems,

local transportation systems, and

the nature and extent of electricity deregulation.

Environmental Matters and Legal Proceedings We discuss details of our environmental matters in Item 15 Note 27 to our Consolidated Financial Statements and Item 1 Business Environmental Matters section. We discuss details of our legal proceedings in Item 15 Note 25 to our Consolidated Financial Statements. Some of this information is about costs that may be material to our financial results.

Impact of inflation on our results Unless discussed specifically in the relevant segment, for the years ended December 31, 2005 and 2004, the period of December 6 through December 31, 2003 and the period January 1, 2003 through December 5, 2003 the impact of inflation and changing prices (due to changes in exchange rates) on our revenue and income from continuing operations was immaterial.

Results of Operations

Note: These historical results do not include the results of Texas Genco, and therefore represent the results of NRG Energy, Inc. s consolidated results only for the periods presented.

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The following table provides operating income by segment for the year ended December 31, 2005:

	Reorganized NRG For the Year Ended December 31, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions, except MWh, CDD and HDD data)						
Energy revenue	$ 1,444	$ 330	$ 1	$ 11	$ 144	$ 84	$ 2,014
Capacity revenue	291	186		5		81	563
Hedging & risk management activity	(285)	(1)			43	(5)	(248)
Alternative revenue				2		189	191
O&M fees						20	20
Other revenue	104	37		(3)	25	5	168
Operating revenues	1,554	552	1	15	212	374	2,708
Cost of energy	871	368	1	14	93	182	1,529
Derivative cost of energy	(2)						(2)
Other operating expenses[1]	393	104	5	16	99	121	738
Depreciation and amortization	74	61	1	7	27	24	194
Operating income/ (loss)	218	20	(6)	(28)	(7)	41	238
MWh sold[2] (in thousands)	16,128	11,710	6	77	5,495		
Market indicators:							
Average natural gas price Henry Hub ($/MMbtu)							$ 8.89
Average on-peak market power prices ($/MWh)	$ 91.98	$ 69.96	$ 71.06	$ 63.76			
Cooling Degree Days, or CDDs[3]	1,604	2,825	776	970			
CDD s 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs[3]	10,449	1,638	2,563	5,095			
HDD s 30 year rolling average	10,479	1,888	2,790	5,436			

(1)

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

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

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

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The following table provides operating income by segment for the year ended December 31, 2004:

	Reorganized NRG						
	For the Year Ended December 31, 2004						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions, except MWh, CDD and HDD data)						
Energy revenue	$ 853	$ 219	$ 10	$ 15	$ 159	$ 109	$ 1,365
Capacity revenue	265	183	(4)	84		84	612
Hedging & risk management activity	58			1	15	2	76
Alternative revenue				2		174	176
O&M fees						21	21
Other revenue	75	16	(3)	(8)	7	11	98
Operating revenues	1,251	418	3	94	181	401	2,348
Cost of energy	521	223	5	10	79	168	1,006
Derivative cost of energy							
Other operating expenses(1)	338	71	5	42	83	154	693
Depreciation and amortization	73	62	1	21	24	27	208
Operating income/(loss)	318	58	(9)	(5)	(5)	36	393
MWh sold(2) (in thousands)	14,259	10,569	77	5	5,189		
Market indicators:							
Average natural gas price Henry Hub ($/MMbtu)							$ 5.89
Average on-peak market power prices ($/MWh)	$ 63.53	$ 45.76	$ 53.16	$ 43.31			
Cooling Degree Days, or CDDs(3)	1,031	2,547	888	590			
CDD s 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs(3)	10,256	1,557	2,347	4,987			
HDD s 30 year rolling average	10,479	1,888	2,790	5,436			

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

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

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

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The following table provides operating income by segment for the period December 6, 2003 through December 31, 2003:

	Reorganized NRG						
	For the Period from December 6, 2003 through December 31, 2003						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions, except MWh, CDD and HDD data)						
Energy revenue	$ 49	$ 15	$	$	$ 10	$ (10)	$ 64
Capacity revenue	14	11		5		7	37
Hedging & risk management activity					2		2
Alternative revenue						12	12
O&M fees						1	1
Other revenue	6	1		(1)		15	21
Operating revenues	69	27		4	12	25	137
Cost of energy	28	15			6	14	63
Derivative cost of energy							
Other operating expenses[1]	25	4		3	4	9	45
Depreciation and amortization	5	3		2	1	1	12
Operating income/(loss)	11	4					15
Market indicators:							
Average natural gas price Henry Hub ($/MMbtu)							$ 6.28
Average on-peak market power prices ($/MWh)	$ 60.75	$ 39.98	$ 49.08	$ 33.09			
Cooling Degree Days, or CDDs[3]							
CDD s 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs[3]	1,494	377	427	803			
HDD s 30 year rolling average	10,479	1,888	2,790	5,436			

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

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

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

Upon our emergence from bankruptcy, we adopted the Fresh Start Reporting provisions of SOP 90-7. Accordingly, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company s financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start, therefore, the Predecessor Company s and the Reorganized NRG s amounts are discussed separately for comparison and analysis purposes, herein.

The following table provides operating income by segment for the period January 1, 2003 through December 5, 2003:

	Predecessor NRG						
	For the Period from January 1, 2003 through December 5, 2003						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(in millions, except MWh, CDD and HDD data)						
Energy revenue	$ 554	$ 196	$ 5	$ 9	$ 122	$ 24	$ 910
Capacity revenue	235	160	19	74		78	566
Hedging & risk management activity	19						19
Alternative revenue				2		80	82
O&M fees				2		11	13
Other revenue	53	1		(1)	29	126	208
Operating revenues	861	357	24	86	151	319	1,798
Cost of energy	470	188	4	7	72	104	845
Derivative cost of energy	4				(9)		(5)
Other operating expenses[1]	326	59	4	39	61	195	684
Depreciation and amortization	90	34	11	30	17	29	211
Operating income/ (loss)	(1,331)	(384)	(101)	(465)	(68)	5,734	3,385
Market indicators:							
Average natural gas price Henry Hub ($/MMbtu)							$ 5.43
Average on-peak market power prices ($/MWh)	$ 61.78	$ 41.53	$ 48.64	$ 37.83			
Cooling Degree Days, or CDDs[3]	1,164	2,583	900	633			
CDD s 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs[3]	11,404	1,836	2,455	5,586			
	10,479	1,888	2,790	5,436			

HDD s 30 year rolling average

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

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

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

For year ended December 31, 2005 compared to the year ended December 31, 2004

Significant Events Reflected in our Results of Operations During 2005

Extreme weather conditions, including Hurricanes Katrina and Rita, contributed to the increase in the sale price of power. This increase in power prices drove the net mark-to-market losses of $119 million primarily associated with forward financial electric sales in support of our Northeast assets.

As compared to the year ended December 31, 2004, on-peak electricity prices increased between 43% to 53% in the various markets we operate, whereas our total domestic coal costs, which are largely contracted, increased only 17% increasing our dark spreads. Gas and oil prices increased 50% and 49%, respectively, resulting in higher spark spreads, but compressed oil margins as compared to the same period last year(1)

Total generation increased for the year ended December 31, 2005 compared to 2004 by 5%.

We began selling excess emission allowances, and have recognized a net gain of $31 million during 2005.

Forced outages at our Huntley, Dunkirk, Indian River and Big Cajun II plants during 2005 negatively impacted our generation by 2.4 million MWh.

We repurchased $645 million in aggregate principal amount of our Second Priority Notes, resulting in $45 million of refinancing charges.

We sold a number of non-core assets including, Enfield, our Northbrook assets and our remaining Kendall interest for a total of $106 million in proceeds and a net gain of approximately $32 million.

We announced the signing of a sale agreement for Rocky Road resulting in an impairment charge of $20 million.

We wrote-down our interest in the Saguaro Power Company by $27 million.

Consolidated Discussion:

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $2,708 million for the year ended December 31, 2005 compared to $2,348 million for the year ended December 31, 2004, an increase of $360 million. Energy revenues for the year ended December 31, 2005 increased $649 million from $1,365 million to $2,014 million. Of the $2,014 million, 87% were merchant as compared to 70% for the year ended December 31, 2004. The increase in energy revenues versus 2004 was driven by both increased prices and the increased merchant generation from our Northeast assets. Energy revenues from our domestic coal assets increased by $314 million, all due to increased power prices, as generation from our domestic coal assets decreased 5% for the year ended December 31, 2005 as compared to the same period in 2004. This decrease in generation was due to both planned and unplanned outages at Huntley, Indian River, and Big Cajun II during the second and fourth quarters, and the time we typically perform outage work. Energy revenue from our gas assets in New York City increased by $176 million, including $23 million in NYISO final settlement payments. Of the remaining $153 million, both price and generation nearly equally contributed to the increase. Energy revenues from our oil-fired assets rose by $211 million, 86% due to higher volumes following an increase in summer demand as the generation from these assets increased by 122% for the year ended December 31, 2005 as compared to the same period in 2004. Additionally, a one-time payment of $39 million from the Connecticut Light and Power settlement contributed to energy revenue during the second quarter of 2004.

Capacity revenues for the year ended December 31, 2005 were $563 million compared to $612 million for the year ended December 31, 2004, a reduction of $49 million. Capacity revenues were unfavorable versus last year due to the loss of $56 million capacity revenues from the Kendall facility, which was sold in the fourth

1 Per the Henry Hub gas price index published by *Platts Gas Daily*.

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quarter of 2004, and the expiration of the Rockford tolling agreement in May 2005 which reduced year-on-year results by $23 million. Capacity revenues from our western New York plants decreased by $10 million due to the addition of new generation and increased imports in New York, which depressed capacity prices for our assets in the western New York market during the first half of 2005. This loss was offset by a $44 million increase in capacity revenues from our Connecticut assets. This increase is related to the additional $24 million capacity revenues recorded in 2005 related to our Connecticut RMR settlement agreement. Alternative revenues for the year ended December 31, 2005 and 2004 were $191 million and $175 million, respectively. Increased generation due to the hotter weather this summer and an increase in contract rates from our Thermal and Resource Recovery operations positively impacted the alternative revenues results.

Other revenues include emission allowance sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the year ended December 31, 2005, other revenues totaled a $168 million compared to $98 million of other revenues for the same period in 2004. The increase is due to higher emission allowance revenues, higher physical gas sales and lower contract amortization, offset by lower expense recovery revenues. Please see our discussion below as to our emission allowance position and sales. The increase in other revenues was also attributed to $33 million in higher gas sales. The increase in gas sales is primarily related to a new gas sale agreement entered into in the third quarter of 2005 by the South Central region, where revenues from gas sales increased by $23 million. We entered into this agreement in conjunction with power purchase agreements to minimize our market purchases during peak months. Lower contract amortization of $30 million is related to contracts rolling off over the course of time. Finally, during the year ended December 31, 2005, expense recovery revenues were $29 million lower versus the comparable period in 2004. Expense recovery revenues are associated with our Connecticut RMR agreements and we reached our maximum payment under that agreement during the first quarter of 2005.

Sale of Excess SO_2 Emission Allowances We actively manage our surplus emission allowance position. During the later half of 2005, we began trading a portion of our excess SO_2 emission allowances to third parties. Revenues from the sale of emission allowances to third parties net of purchases totaled $31 million in 2005, excluding the EPA auction results. The following table provides the sales activity and our balance of emission allowances (excluding Texas Genco) for vintage years, through 2009:

	Tons	Average Sales Price	Revenue
Balance of NRG SO_2 Emissions Credits Allowances, as of December 31, 2004	897,653	n/a	n/a
Sales during 2005	35,052	$ 889	$ 31 million
Consumed	(115,810)		
Balance of NRG SO_2 Emissions Credits Allowances, as of December 31, 2005	746,791	n/a	n/a
Completed Sales between January 1 and February 28, 2006	46,077	$ 1,180	$ 54 million
Balance of NRG SO_2 Emissions Credits Allowances, as of February 28, 2006	700,714	n/a	n/a

In addition to our SO_2 emission allowance balances presented above, after the closing of the acquisition of Texas Genco, the combined NRG balance of excess SO_2 emissions allowances for vintage years through 2009 is 1,329,066 tons on February 28, 2006.

We expect to continue the active management of our SO_2 emission allowances in excess of our forecast generation needs.

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Hedging and Risk Management Activity

	For the Year Ended December 31, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In millions)			
Net gains/ (losses) on settled positions, or financial revenues	$ (132)	$ (1)	$	$	$ 35	$ (5)	$ (103)
Mark-to-market results							
Reversal of previously recognized unrealized (gains)/losses on settled positions	(59)				1		(58)
Net unrealized gains/ (losses) on open positions related to economic hedges	(119)				7		(112)
Net unrealized gains/ (losses) on open positions related to trading activity	27						27
Subtotal mark-to-market results	(151)				8		(143)
Total derivative gain/ (loss)	$ (283)	$ (1)	$	$	$ 43	$ (5)	$ (246)

Hedging and Risk Management Activity The total derivative loss for the year was approximately $246 million, comprised of $103 million in financial revenue losses and $143 million of mark-to-market losses. The $103 million loss of financial revenues represent the settled value for the year of all financial instruments including but not limited to financial swaps on power. Of the $143 million of mark-to-market losses, $112 million represents the change in fair value of forward sales of electricity and fuel $114 million losses associated with electricity sales and $2 million gain associated with cost of fuel, the reversal of $58 million of mark-to-market gains which ultimately settled as financial revenues and $27 million mark-to-market gain related to trading activity. These activities primarily support our Northeast assets. The $112 million domestic loss related to forward sales during 2005 compares to a $59 million gain for the same period during 2004.

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

In addition to the hedging techniques used until now, we expect to utilize hedging strategies that are option-based with a goal of establishing a floor on earnings, leaving upside market participation, minimizing mark-to-market swings and optimizing collateral support of our hedging program. For 2007, we have already locked in a floor on 30%

of our baseload coal generation at current forward prices while preserving our ability to benefit from further upward movement in northeastern electricity prices.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the year ended December 31, 2005 was $2,067 million. Cost of majority-owned operations for the year ended December 31, 2004 was $1,489 million or 63% of revenues from majority-owned operations. The increase is related to the cost of energy, which increased by $521 million, to $1,529 million or 56% of revenues for the year ended December 31, 2005 from $1,008 million or 43% of revenues for the same period in 2004. The increase in the cost of energy as a percentage of revenues is driven by the higher mark to market loss in revenues, by both higher price and generation in the Northeast region and higher purchased energy and gas sales in the South Central region. Total gas costs increased by $163 million, $124 million in the New York City assets alone. Of the increase at our New York City assets, $15 million was due to increased gas purchases for resale, with approximately $67 million due to increased generation. The

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South Central region s gas costs increased by $25 million due to physical gas purchases related to a new gas sale agreement entered into in the third quarter of 2005 to support certain tolling arrangements. Total oil costs for the company increased by $165 million, 65% due to increased generation from our oil-fired assets, and the remainder due to an increase in price. Total coal costs increased by $71 million. The increase at our domestic coal-fired assets is solely due to price increases, as overall generation from our coal-fired assets decreased for the year ended December 31, 2005 by 5% as compared to the same period in 2004 due to the planned and forced outages at our Huntley, Indian River and Big Cajun II facilities. The increase in coal prices is related to new low-sulfur coal and rail contracts which became effective in April 2005. Additionally, our Indian River plant uses a higher portion of eastern coal that experienced a significant cost increase in 2005. We have increased our percentage blend of low-sulfur coal over the year as compared to the same period last year. This had the effect of mitigating the increase in coal and coal transportation costs as low sulfur coal prices have not increased as much as regular coal prices. Total purchased energy increased by $112 million due to increases at our South Central region. Higher long-term contract load demand due to the extreme weather, a 100-MW around-the-clock sale to Entergy, a tolling agreement, and the forced outages during the second quarter, required South Central to purchase energy to meet its contract load obligations.

Other Operating Expenses during 2005 totaled $737 million versus $693 million in the comparable period of 2004, an increase of $44 million. This increase is driven by a $51 million, or 11%, increase in operating and maintenance costs. Major maintenance projects and more extensive outages in 2005, as compared to 2004, contributed $33 million to the increase. The low-sulfur coal conversions and turbine overhauls of the western New York plants and Indian River plant was a main focus for many of the major maintenance and outages in 2005. South Central also went through a significant outage to install a low-NOX burner on one of its units and an additional outage was completed this Fall to address reliability issues experienced at the Big Cajun II unit earlier in the year. Normal maintenance increased by $9 million or 9% due to the increased run time at our plants this summer. Additionally, in 2004, a settlement with a third party vendor regarding auxiliary power charges reduced 2004 operating and maintenance expenses by $7 million.

Depreciation and Amortization

Our depreciation and amortization expense for the year ended December 31, 2005 and 2004 was approximately $194 million and $208 million, respectively. The decrease in depreciation and amortization from 2005 to 2004 is due to the 2004 sale of our Kendall plant, which contributed approximately $14 million in depreciation and amortization expense during 2004.

General, Administrative and Development

Our G&A costs for the year ended December 31, 2005 were $197 million compared to $210 million for the same period in 2004, a decrease of $13 million. Corporate costs represent $94 million or 3% of revenues and $113 million or 5% of revenues for the years ended December 31, 2005 and 2004, respectively. G&A costs have been favorably impacted by $11 million in reduced bad debt expense associated with notes receivable from third parties. Additionally, external consulting expenses decreased in 2005 as compared to 2004 by approximately $11 million primarily related to reduced tax and legal consulting. These favorable impacts were offset by a $5 million increase in information technology related expenses primarily associated with increased compliance costs related to Sarbanes Oxley and the relocation from Minneapolis.

Corporate Relocation Charges

During the year ended December 31, 2005, charges related to our corporate relocation activities were approximately $6 million as compared to $16 million in 2004. Included in this year s charges is approximately $3 million related to the lease abandonment charges associated with our former Minneapolis office with the remainder related to the relocation, recruitment and transition costs. In 2004, we recorded $16 million primarily related to employee severance and termination benefits and employee-related transition costs. We completed the physical move of our relocation in 2004 when the majority of costs were incurred. We do not expect any material relocation charges in 2006.

Equity in Earnings of Unconsolidated Affiliates

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

Other equity investments included in the 2005 results include MIBRAG and Gladstone which comprised $26 million and $24 million for the year ended December 31, 2005, respectively. For the comparable period in 2004, MIBRAG and Gladstone earned $21 million and $18 million, respectively. MIBRAG s equity earnings for 2004 were negatively impacted by an outage at our Schkopau plant; additionally, MIBRAG recorded a lower asset retirement obligation in 2005 as compared to 2004. Gladstone s earnings in 2005 were greater than 2004 due to lower major maintenance expense and an approximate $1 million recovery in business interruption insurance.

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

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

In December 2005, we executed an agreement with Dynegy to sell our 50% interest in Rocky Road LLC in conjunction with our purchase of Dynegy s 50% interest in WCP. Based on this arms length transaction rendering the fair value of our investment in Rocky Road at $45 million, we subsequently impaired our investment to this fair value by an approximate write down of $20 million. We expect to close the sale of our interest of Rocky Road during the first half of 2006. We also recorded an impairment of $27 million on our investment in Saguaro. With the expiration of its gas supply contract, Saguaro began recording operating losses during the second half of 2005, triggering a permanent write down to NRG s investment value in Saguaro.

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

Other Income, net

Other income had a net increase of $35 million during the year ended December 31, 2005 as compared to the same period in 2004. Other income in 2005 was favorably impacted by a $14 million gain from the settlement related to our TermoRio project in Brazil and a gain of approximately $4 million related to the resolution of a contingency from the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. Other income was also favorably impacted by $14 million of higher interest income related to more efficient management of our cash balances. These favorable results were offset by a $3 million reserve relating to the ongoing TermoRio litigation.

Refinancing expense

Refinancing expenses for the year ended December 31, 2005 and 2004 were $56 million and $72 million, respectively. During 2005, as part of our continuing effort to manage our capital structure, we redeemed and purchased a total of $645 million of our Second Priority Notes. As a result of the redemption and purchases, we incurred $55 million in premiums and write-offs of deferred financing costs. Our Australia region also refinanced its project debt for better terms, resulting in the write-off of approximately $10 million of debt premium, i.e. refinancing income. We also incurred an additional $11 million in refinancing fees during 2005 related to the amortization of a bridge loan commitment fee that we paid related to the Acquisition of Texas Genco.

As part of our new financing in 2006 in conjunction with the acquisition of Texas Genco, we paid a bridge loan commitment fee of approximately $45 million to ensure that we would have the proper financing in place for the said acquisition. This amount is being amortized over time, and during 2005 we amortized approximately $11 million to refinancing expense. The remaining balance of this amount will be expensed during the first quarter of 2006 as we finalized the new financings related to the acquisition of Texas Genco.

During the year ended December 31, 2004, we refinanced certain amounts of our term loans with additional corporate level high yield notes for better terms, which resulted in $15 million of prepayment penalties and a $15 million write-off of deferred financing costs. Additionally, we refinanced our senior credit facility in December 2004 and recorded $14 million of prepayment penalties and a $27 million of write-off of deferred financing costs.

Interest expense

Interest expense for the year ended December 31, 2005 was $197 million as compared to $266 million for the same period in 2004, a reduction of $69 million. Interest expense was favorably impacted by the sale of Kendall which incurred $25 million of interest expense year ended December 31, 2004. Additionally, the refinancing of our Senior Credit Facility on December 23, 2004 lowered our interest rate by 212.5 basis points and the $645 million redemption and purchases of our Second Priority Notes during 2005 reduced interest expense on our corporate debt by approximately $50 million.

Income Tax Expense

Income tax expense was approximately $43 million and approximately $65 million for the years ended December 31, 2005 and 2004, respectively. The overall effective tax rate was 35.8% and 28.7% for the years ended December 31, 2005 and 2004, respectively. The effective income tax rate for the year ended December 31, 2005 and 2004 differs from the U.S. statutory rate of 35% due to the earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate, rendering an effective tax rate of 17.3% and 9.7%, respectively, on foreign income. Our 2005 domestic income tax effective rate increased due to our gain on the sale of Enfield and the taxable dividend received pursuant to the American Jobs Creation Act of 2004. Also see our tax rate reconciliation disclosure in Note 22, *Income Taxes*, to the Condensed Consolidated Financial Statements.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the adjustment of valuation allowances in accordance with SFAS 109. These factors and others, including our 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 Taxes

During the year ended December 31, 2005 and 2004, we recorded a gain from discontinued operations of $7 million and $25 million, respectively, as we continued to divest certain non-core assets. Discontinued operations for the year ended December 31, 2005 consist of Audrain, the Northbrook New York and Northbrook Energy assets and various expenses related to the final settlements of McClain. During the year ended December 31, 2004, discontinued operations consisted of the results of Audrain, the two Northbrook entities, McClain, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). With the exception of Audrain, Northbrook New York and Northbrook Energy, all discontinued operations were sold prior to December 31, 2004.

As of December 31, 2005, the sale of Audrain is still pending and remains subject to regulatory approvals. Ameren s application to assume certain obligations of Audrain is pending before the Missouri Public Service Commission .. The case filed with the FERC seeking authorization for the transaction pursuant to section 203 of the Federal Power Act has been protested by the Missouri Joint Municipal Electric Utility Commission. The pre-merger waiting period under the Hart-Scott-Rodino Antitrust Improvement Act expired January 19, 2006. Despite the above, we still expect to close this sale during the first half of 2006.

Regional Discussion

Northeast Region Results

Operating Income

For the year ended December 31, 2005, operating income for the Northeast region was $218 million, as compared to $318 million for the same period in 2004, a decrease of $100 million. This decrease is due to $119 million net MTM losses reported by the Northeast associated with forward sales of electricity as compared to a $59 million net MTM gain booked in 2004. Excluding net MTM losses or gains, the Northeast operating income increased by $52 million. This increase was largely due to increased power prices, wider dark spread margins, and increased generation from the Northeast gas and oil assets. With higher than average temperatures this summer, on-peak electricity prices increased 43% to 52% as compared to 2004, while gas and oil prices increased 50% and 49%(1) Spark spreads on our gas and coal margins widened, while oil margins were compressed compared to the same period last year. The Northeast s New York City assets benefited from the increased spark spreads as they increased their generation output by 52% versus last year, from 1.1 million MWh to 1.7 million MWh due to increased summer demand. Generation from our Northeast oil-fired assets increased by 122%, but oil margins decreased by 25% versus 2004, as our cost per MWh increased by 29% in comparison to the same period in 2004 due to an offsetting increase in oil prices.

Revenues

Revenues from our Northeast region totaled $1,554 million for the year ended December 31, 2005 compared to $1,251 million for the same period in 2004, an increase of $303 million. Revenues for the year ended December 31, 2005 included $1,444 million in energy revenues compared to $853 million for the same period in 2004. Of this $591 million increase, $183 million can be attributed to our New York City assets. Due to outages of local competitors and extreme heat this summer, sold generation from our New York City assets increased by 52% for the year ended December 31, 2005 as compared to 2004. Excluding the $23 million of final NYISO settlement payments, increased generation accounted for 49% of the increase in NYC energy revenues. Our oil-fired assets earned $211 million more in energy revenues, and increased generation 122% during 2005 as compared to 2004; 86% of the increased energy revenues were due to increased generation. Our coal assets recorded higher energy revenues of $99 million due solely to higher power prices as generation from our coal assets had a minimal decrease for the year ended December 31, 2005.

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

1Per the Henry Hub gas price index published by *Platts Gas Daily*.

Other revenues include emission credit sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues and totaled $104 million for the year ended December 31, 2005 as compared to $75 million the same period in 2004, an increase of $29 million. This increase is related to the additional $43 million in emission allowance sales to both external parties and inter-company sales. In addition, other revenues increased from $6 million in higher gas sales, and $6 million in lower contract amortization as the contracts have rolled off over time. Other revenues were adversely impacted by $29 million in lower expense recovery revenues related to the Connecticut RMR agreement. We reached our maximum payment under that agreement during the first quarter of 2005.

Hedging and Risk Management Activity The total derivative loss for the year was $283 million, comprised of $132 million in financial revenue losses and $151 million of mark-to-market losses. The $132 million loss of financial revenues represent the settled value for the year of all financial instruments including financial swaps and options on power. Of the $151 million of mark-to-market losses, $119 million represents fair value of forward sales of electricity and fuel $121 million losses associated with electricity sales and $2 million gain associated with cost of fuel, the reversal of $59 million of mark-to-market gains which ultimately settled as financial revenues and $27 million mark-to-market gain related to trading activity. These activities primarily support our Northeast assets.

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

Cost of energy

Cost of energy increased by $350 million for our Northeast region for the year ended December 31, 2005 compared to the same period in 2004. Oil fuel costs in our Northeast region increased by $162 million, where 65% of the increase was due to increased generation. The Northeast s gas fuel costs increased by $129 million. Higher gas sales from our New York City assets drove $15 million of the increase, with $109 million of the increase related to higher prices and demand for our NYC assets. Coal costs increased by $61 million, due to increased prices, although our coal-fired generation in the Northeast had a minimal decrease during 2005 as compared to 2004, specifically due to scheduled and unplanned outages at our western New York and Indian River facilities during the second and fourth quarters. Of the $61 million increase in coal cost, 71% was due to increases at our Indian River plant. Our Indian River plant uses a higher portion of eastern coal, whose price experienced a significant cost increase during 2005.

Other Operating Expenses

Other operating costs for our Northeast region increased by $55 million for the year ended December 31, 2005 compared to the same period in 2004. This increase was driven by operating and maintenance costs, led by higher major maintenance costs. The low-sulfur conversion projects continued at our Western New York plants and began at our Indian River plant this year and major outages related to turbine overhauls took place at our Western New York and Indian River plants. The increased number and extensiveness of the outages contributed to the $14 million increase in major maintenance expense this year. Additionally, in 2004, a settlement with a third party vendor regarding auxiliary power charges reduced 2004 operating and maintenance expenses by $7 million.

Other operating expenses for the Northeast region include the administrative regional office costs, other non-income tax expense, insurance and corporate allocations. These costs increased by $30 million in 2005 compared to 2004, $14 million of which was due in non-income tax expense as we recognized property tax credits in 2004. Additionally, regional office and corporate allocations also increased per our new allocation methodology as discussed in Item 15 Note 21, *Segment Reporting*, to the Consolidated Financial Statements.

South Central Region Results

Operating Income

For the year ended December 31, 2005, the South Central region realized operating income of $20 million, as compared to $58 million for the year ended December 31, 2004. During 2005, our Big Cajun II facility experienced several forced outages during the summer months, at which time contract demand and replacement power costs were at their highest. Generation for 2005 decreased by 6% from 10.6 million MWh to 9.9 million MWh versus the same period in 2004, with 0.2 million MWh lost due to forced outages. These outages contributed to the purchase of $114 million in additional purchased energy required to meet contract load-following obligation in the merchant market at costs higher than our coal-based generating assets. In addition, during 2005, South Central had three planned outages versus one major planned outage during 2004, which increased major maintenance by $16 million as compared to the year ended December 31, 2004.

Revenues

Revenues from our South Central region were $552 million for the year ended December 31, 2005 compared to $418 million for the same period in 2004, an increase of $134 million. Revenues for the year ended December 31, 2005 included $330 million in energy revenues, of which 62% were contracted. This compares to $219 million of energy revenues for the year ended December 31, 2004, 73% of which were contracted. This increase of $111 million in energy revenues and the lower percentage contracted was due to increased merchant energy sales following higher power prices, favorable weather, and nuclear plant outages in the region. Also, a round-the-clock 100 MW sale to Entergy and a tolling agreement which at times provided power that could be resold at a higher price helped to boost merchant revenues. Other revenues include physical gas sales and Fresh Start-related contract amortization. For the year ended December 31, 2005, other revenues totaled $37 million compared to $16 million for the year ended December 31, 2004, with the increase due to $23 million increase in physical gas sales related to a new gas sale agreement entered into in July 2005. We entered into this agreement in conjunction with power purchase agreements to minimize our market purchases during peak months.

Cost of Energy

South Central s cost of energy increased by $145 million for the year ended December 31, 2005 compared to the same period in 2004. Of this amount, $114 million is due to higher purchased energy costs. During 2005, our Big Cajun II facility experienced a number of forced outages, encountered high demand from the Region s long-term contracts, and entered into 100-MW around-the-clock sale to Entergy, and a tolling agreement, all of which required the purchase of energy to meet contract load obligations. Purchased energy per MWh increased by 238% versus the same period in 2004. Additionally, due to the extreme weather conditions and increasing gas prices, the average purchased energy price increased $18.20 per MWh for the year ended December 31, 2005 as compared to the same period in 2004.

Other Operating Expenses

Other operating expenses increased by $33 million for the year ended December 31, 2005 compared to the same period in 2004, with $16 million of the increase related to increased planned and unplanned outages at our Big Cajun II facility, and $13 million related to regional office and the new NRG allocation methodology discussed in Item 15 Note 21, *Segment Reporting*, to the Consolidated Financial Statements.

Western Region Results

For the year ended December 31, 2005, the Western region realized an operating loss of $6 million, as compared to an operating loss of $9 million for the same period in 2004, a reduction of $3 million in our loss.

This reduction is due to the payment of CAISO penalties paid by our Red Bluff and Chowchilla facilities in 2004, offset by the expiration of the Red Bluff RMR contract as of December 31, 2004.

Other North America Region Results

For the year ended December 31, 2005, the Other North America region realized an operating loss of $28 million on revenues of $15 million, as compared to an operating loss of $5 million and revenues of $94 million for the year ended December 31, 2004. This unfavorable variance is primarily related to the sale of Kendall and the expiration of a tolling agreement at our Rockford facility. Both Kendall and Rockford had operating income of $3 million each, for the year ended December 31, 2004 and revenues of $73 million and $15 million, respectively. Other operating expenses and depreciation and amortization for our Other North America region for the year ended December 31, 2005 were $16 million and $7 million, respectively. For the year ended December 31, 2004, other operating expenses and depreciation and amortization were $42 million and $21 million, respectively. The favorable variance in both of these is due to the sale of Kendall.

Australia Region Results

Operating Income

For the year ended December 31, 2005, the Australia region realized an operating loss of $7 million, as compared to an operating loss of $5 million for the same period in 2004. Unseasonably mild weather and weak pool prices in the first quarter drove the unfavorable results as compared to last year. Higher generation for the year ended December 31, 2005 helped to offset weak pool prices, with generation increasing 6% over 2004.

Revenues

Revenues from our Australia region totaled $212 million for the year ended December 31, 2005 compared to $181 million for the year ended December 31, 2004, an increase of approximately $31 million, with $7 million as a result of the strengthening Australian dollar in 2005. Energy revenues decreased by $15 million primarily due to the weak pool prices experienced in the first quarter of the year. An unseasonably mild summer in Australia drove the average annualized pool price down to $23 per MWh from $30 per MWh in 2004, a reduction of 26%. This decrease was offset by $18 million of financial revenues, representing the settled value of financial instruments, including financial swaps on power, and $10 million of higher derivative revenues, representing the change in fair value of forward sales of electricity and fuel. Additionally, 5% higher generation due to fewer planned outage hours at the Osborne Power Station in 2005 and the full commercialization of the Playford station during the fourth quarter of 2004, helped to offset the impact of the lower pool prices. For the year ended December 31, 2005, other revenues totaled $25 million compared to $7 million of other revenues for the same period in 2004. Other revenues were favorably impacted by lower contract amortization of $15 million in 2005 as a significant contract was canceled in 2004.

Cost of Energy

Fuel costs increased by $14 million, with $10 million of this related to an 18% increase in purchased power from Osborne Power Station in 2005 and $3 million due to additional gas expenses to support these higher generation levels. These increased costs are offset by increased revenue from merchant electricity and gas sales in 2005 related to our Osborne plant. Fuel oil costs in 2005 were approximately $1 million higher due to a combination of increased world oil prices and increased starts at Playford.

Other Operating Expenses

Other operating expenses for Australia for the year ended December 31, 2005 increased by $16 million over the same period in 2004. Operating and maintenance expense increased by $10 million in 2005 with $3 million attributable to the strengthening Australian dollar. Increased operational and maintenance costs relating to our Playford power station in addition to higher coal production costs to support the higher generation levels led to a further $2 million increase. Significant increases in world oil prices over the 2005 year resulted in $1 million of additional costs related to coal mining and delivery. Labor costs at Flinders were up approximately $1 million, a combination of increasing provision levels for workers compensation claims and increased charges relating to pension charges. Additionally, due to the new NRG allocations methodology as discussed in Item 15 Note 21, *Segment Reporting*, to the Consolidated Financial Statements, the Australia region incurred $6 million in higher corporate allocations as compared to 2004.

For the Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Net Income

Reorganized NRG

For the year ended December 31, 2004, we recorded net income of $186 million, or $1.85 per weighted average share of diluted common stock. These favorable results occurred despite a challenging market environment in 2004. Unseasonably mild weather, high volatility on forward markets and disappointing spot power prices summarize 2004 s events. The NOAA has ranked the mean average temperatures over the past 110 years by season for each of the lower 48 states. The year 2004 started with the winter being colder than normal in the east coast followed by a spring, summer and fall which were among the mildest in the last 110 years throughout most of the United States. Although mild weather in the North America market kept spot market on-peak power prices were low throughout most of the year, relatively high gas and oil prices kept spark spreads on coal-based assets positive.

The overall perception that there would be significant production losses due to Hurricane Ivan ignited a strong pre-heating season rally in natural gas futures during the early fourth quarter. While power prices tracked changes in natural gas prices, this movement was not one for one. As a result, our spark spreads on coal-based generation increased dramatically with the fall 2004 changes in gas prices. During this period we sold forward 2005 power locking in these spark spreads. Forward power prices have fallen considerably from the highs set in October, and many of those forward sales, which were marked-to-market through earnings, significantly contributed to the $57 million unrealized gain recorded in revenue for the year ended December 31, 2004 and as more fully described in Item 15 Note 15 to the Consolidated Financial Statements. The majority of the unrealized gains relate to forward sales of electricity which were realized in 2005. These gains were offset by our South Central region s results, which were negatively impacted by an unplanned outage in the fourth quarter forcing us to purchase power to meet our contract supply obligations. Our results were also favorably impacted by the FERC-approved settlement agreement between NRG Energy and Connecticut Light & Power, or CL&P, and others concerning the congestion and losses obligation associated with a prior standard offer service contract, whereby we received $38 million in settlement proceeds in July 2004. The 2004 results were also positively impacted by $160 million in equity earnings of unconsolidated affiliates including $69 million from our interest in West Coast Power which benefited from warmer than normal temperatures during the year. Impairment charges of $45 million negatively impacted net income; of which $27 million relates to the Kendall asset.

During the period December 6, 2003 through December 31, 2003, we recognized net income of $11 million or $0.11 per share of common stock. From an overall operational perspective our facilities were profitable during this period. Our results were adversely impacted by our having to continue to satisfy the standard offer service contract that we entered into with CL&P in 2000. As a result of our inability to terminate this contract during our bankruptcy proceeding, we continued to be exposed to losses under this contract. These losses were incurred, as we were unable to satisfy the requirements of this contract at a price/cost below the contracted sales price. Upon our adoption of Fresh Start, we recorded at fair value, all assets and liabilities on our opening balance sheet and accordingly we recorded as an obligation the fair value of the CL&P contract. During the period December 6, 2003 through December 31, 2003, we recognized as revenues the entire fair value of this contract effectively offsetting the actual losses incurred under this contract. The CL&P contract terminated on December 31, 2003.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded net income of $2.8 billion. Net income for the period is directly attributable to our emerging from bankruptcy and adopting the Fresh

Start provisions of SOP 90-7. Upon the confirmation of our Plan of Reorganization and our emergence from bankruptcy, we were able to remove significant amounts of long-term debt and other pre-petition obligations from our balance sheet. Accordingly, as part of net income, we recorded a net gain of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) as the impact of our adopting Fresh Start in our statement of operations. $6 billion of this amount is directly related to the forgiveness of debt and settlement of substantial amounts of our pre-petition obligations upon our emergence from bankruptcy. In addition to the removal of substantial amounts of pre-petition debt and other obligations from our balance sheet, we also revalued our assets and liabilities to fair value. Accordingly, we substantially wrote down the value of our fixed assets. We recorded a net $1.6 billion charge related to the revaluation of our assets and liabilities within the Fresh Start Reporting adjustment line of our consolidated statement of operations. In addition to our adjustments related to our emergence from bankruptcy, we also recorded substantial charges related to other items such as the settlement of certain outstanding litigation in the amount of $463 million, write downs and losses on the sale of equity investments of $147 million, advisor costs and legal fees directly attributable to our being in bankruptcy of $198 million and $237 million of other asset impairment and restructuring costs incurred prior to our filing for bankruptcy. Net income for the period January 1, 2003 through December 5, 2003 was favorably impacted by our not recording interest expense on substantial amounts of corporate level debt while we were in bankruptcy and by the continued favorable results experienced by our equity investments.

Revenues from Majority-Owned Operations

Reorganized NRG

Our revenues from majority-owned operations were $2.3 billion for the year ended December 31, 2004 which included $1.4 billion of energy revenues, $612 million of capacity revenues, $175 million of alternative energy revenues, $21 million of O&M fees, $76 million of hedging and risk management activities and $99 million other revenues.

Revenues from majority-owned operations for the year ended December 31, 2004, were driven primarily by our North American operations, primarily our Northeast facilities. Our wholly-owned North America assets generated approximately 29 million MWh during the year 2004 with the Northeast region representing 46% of these MWh s. Of the total $1.4 billion in energy revenues, the Northeast region represented 62%. Our energy revenues were favorably impacted by the FERC-approved settlement agreement between us and CL&P and others, whereby we received $38 million in settlement proceeds in July 2004. These settlement proceeds are included in the All Other segment in the energy revenue category. South Central s energy revenues are driven by our ability to sell merchant energy, which is dependent upon available generation from our coal-based Louisiana Generating company after serving our co-op customer and long-term customer load obligations. Since our load obligation is primarily residential load, our merchant opportunities are largely available in the off-peak hours of the day. Our Australian operations were favorably impacted by strong market prices driven by gas restrictions in January, record high temperatures in February and March, and favorable foreign exchange movements. Our capacity revenues are largely driven by our Northeast and South Central facilities. Our South Central and New York City assets earned 30% and 26% of our total capacity revenues, respectively. In the Northeast, our Connecticut facilities continue to benefit from the cost-based reliability must-run, or RMR agreements, which were authorized by FERC as of January 17, 2004 and approved by FERC on January 27, 2005. The agreements entitle us to approximately $7 million of capacity revenues per month until January 1, 2006, the LICAP implementation date. In the South Central region, our long-term contracts provide for capacity payments. Other North American capacity revenues were generated by our Kendall operation, which had a long-term tolling agreement. During this period we also experienced a favorable impact on our revenues due to the mark-to-market on certain of our derivative contracts wherein we have recognized $57 million in unrealized gains. This gain is related to our Northeast assets and is included in the hedging and risk management activities. Included in Other Revenue in the Northeast are the cost reimbursement funds under the RMR agreement for our Connecticut assets. Our revenues during this period include net charges of $35 million of non-cash amortization of the fair values of various executory contracts recorded on our balance sheet upon our adoption of the Fresh Start provisions of SOP 90-7 in December 2003.

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Our revenues from majority-owned operations were $137 million for the period December 6, 2003 through December 31, 2003.

Predecessor Company

Revenues from majority-owned operations were $1.8 billion for the period January 1, 2003 through December 5, 2003 and include approximately $910 million of energy revenues, $566 million of capacity revenues, $82 million of alternative energy, $13 million of O&M fees, $19 million of hedging and risk management activities and $208 million other revenues. Revenues from majority-owned operations during the period ended December 5, 2003, were driven primarily by our North American operations and to a lesser degree by our international operations, primarily Australia. Our domestic Northeast and South Central power generation operations significantly contributed to our revenues due primarily to favorable market prices resulting from strong fuel and electricity prices. Our Australian operations were favorably impacted by foreign exchange rates. During this period we also experienced an unfavorable impact on our revenues due to continued losses on our CL&P standard offer contract and the mark-to-market on certain of our derivatives.

Cost of Majority-Owned Operations

Our cost of majority-owned operations for the year ended December 31, 2004 was $1.5 billion or 63% of revenues from majority-owned operations. Cost of majority-owned operations consist of $1.006 billion of cost of energy (primarily fuel and purchased energy costs), or 43% of revenues from majority-owned operations and $483 million of operating expenses, or 21% of revenues from majority-owned operations. Operating expenses consist of $207 million of labor related costs, $235 million of operating and maintenance costs, $38 million of non-income based taxes and $3 million of asset retirement obligation accretion.

Cost of Energy

Fuel related costs include $476 million in coal costs, $233 million in natural gas costs, $105 million in fuel oil costs, $39 million in transmission and transportation expenses, $100 million of purchased energy costs, $35 million in other costs and $18 million in non-cash SO_2 emission credit amortization resulting from Fresh Start accounting. The Northeast region consumed 50%, 64% and 91% of total coal, natural gas and oil expenditures, respectively. The South Central region, which is comprised mainly of our Louisiana base-loaded coal plant, consumed 32% of our total coal expenditures.

Operating Expenses

Reorganized NRG

Operating expenses related to continuing operations for the year ended December 31, 2004 were $483 million or 21% of revenues from majority-owned operations. Operating expenses include labor, normal and major maintenance costs, environmental and safety costs, utilities costs, and non-income based taxes. Labor costs include regular, overtime and contract costs at our plants and totaled $207 million. The Northeast region, where the majority of our assets reside, represents 53% of total labor costs; Australia represents 18%, while our South Central region represents 12%. Of the total O&M costs, normal and major maintenance at our plants accounted for $176 million, or 36% of total operating costs. Maintenance costs were largely driven by planned outages across our fleet, and the low-sulfur coal conversion in western New York. The Northeast region represented over half of the normal and major maintenance, with a total of $99 million in costs in 2004 while Australia had $40 million in normal and major maintenance, or 23%. Operating expenses were positively impacted by a $7 million favorable settlement with a vendor regarding auxiliary power charges. Non-income based taxes totaled $38 million net of $35 million in property tax credits, primarily associated with an enterprise zone program.

Cost of majority-owned operations was $95 million, or 69% of revenues from majority-owned operations for the period December 6, 2003 through December 31, 2003. Cost of energy for this period was $63 million or 46% of revenues from majority-owned operations and operating expenses were $32 million, or 23% of revenues from majority-owned operations. Labor during this period totaled $11 million. Normal and major maintenance was $12 million with 67% of the total normal and major maintenance for this time period coming from our Northeast region.

Predecessor Company

Cost of majority-owned operations was $1.4 billion, or 75% of revenues from majority-owned operations for the period January 1, 2003 through December 5, 2003. Cost of majority-owned operations was unfavorably impacted by increased generation in the Northeast region, partially offset by a reduction in trading and hedging activity resulting from a reduction in our power marketing activities. Our international operations were impacted by an unfavorable movement in foreign exchange rates and continued mark-to-market of the Osborne contract at Flinders resulting from lower pool prices.

Depreciation and Amortization

Reorganized NRG

Our depreciation and amortization expense related to continuing operations for the year ended December 31, 2004 was $208 million. Depreciation and amortization consists primarily of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property. Upon adoption of Fresh Start, we were required to revalue our fixed assets to fair value and determine new remaining lives for such assets. Our fixed assets were written down substantially upon our emergence from bankruptcy. We also determined new remaining depreciable lives, which are, on average, shorter than what we had previously used primarily due to the age and condition of our fixed assets.

Depreciation and amortization expense for the period December 6, 2003 through December 31, 2003 was $12 million. Depreciation and amortization expense consists of the allocation of our newly valued basis in our fixed assets over newly determined remaining fixed asset lives.

Predecessor Company

Our depreciation and amortization expense related to continuing operations for the period January 1, 2003 through December 5, 2003 was $211 million. During this period, depreciation expense was unfavorably impacted by the shortening of the depreciable lives of certain of our domestic power generation facilities located in the Northeast region and the impact of recently completed construction projects. The depreciable lives of certain of our Northeast facilities, primarily our Connecticut facilities, were shortened to reflect economic developments in that region. Certain capitalized development costs were written-off in connection with the Loy Yang project resulting in increased expense. Amortization expense increased due to reducing the life of certain software costs.

General, Administrative and Development

Reorganized NRG

Our general, administrative and development costs related to continuing operations for the year ended December 31, 2004 were $210 million. Of this total, $111 million or 5% of revenues from majority-owned operations represents our corporate costs, with the remaining $99 million representing costs at our plant operations. Corporate costs are primarily comprised of corporate labor, external professional support, such as legal, accounting and audit fees, and office expenses. Corporate general, administrative and development expenses were negatively impacted this year by increased legal fees, increased audit costs and increased consulting costs due to our Sarbanes Oxley testing and implementation. Plant general, administrative and development costs primarily include insurance and external consulting costs. Plant insurance costs were $41 million. Additionally, we recorded $12 million in bad debt expense related to notes receivable.

General, administrative and development costs were $13 million, or 10% of revenues from continuing operations for the period December 6, 2003 to December 31, 2003. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Predecessor Company

Our general, administrative and development costs related to continuing operations for the period January 1, 2003 to December 5, 2003 were $170 million or 10% of revenues from majority-owned operations. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Other Charges (Credits)

Reorganized NRG

For the year ended December 31, 2004, we recorded other charges of $48 million, which consisted of $16 million of corporate relocation charges, $13 million of reorganization credits and $45 million of restructuring and impairment charges.

For the period December 6, 2003 through December 31, 2003 we recorded $2 million of reorganization charges.

Predecessor Company

During the period January 1, 2003 to December 5, 2003, we recorded other credits of $3.3 billion, which consisted primarily of $229 million related to asset impairments, $463 million related to legal settlements, $198 million related to reorganization charges and $8 million related to restructuring charges. We also incurred a $4.2 billion credit related to Fresh Start adjustments.

Other charges (credits) consist of the following:

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
		(In millions)	
Corporate relocation charges	$ 16	$	$
Reorganization items	(13)	2	198
Impairment charges	45		229
Restructuring charges			8
Fresh Start adjustments			(4,220)
Legal settlement			463
Total	$ 48	$ 2	$ (3,322)

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. The corporate headquarters staff were streamlined as part of the relocation, as functions were either reduced or shifted to the regions. As of December 31, 2005, the transition of the corporate headquarters is complete. During the year ended December 31, 2004, we recorded $16 million for charges related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. See Item 15 Note 8 to our consolidated financial statements for more information.

Costs not classified separately as relocation charges include rent expense of our temporary office in Princeton, construction costs of our new office and certain labor costs. All costs relating to the corporate relocation that are not classified separately as relocation charges, except for approximately $6 million of related capital expenditures will be expensed as incurred and included in general, administrative and development expenses. Cash expenditures for 2004, including capital expenditures, were $22 million.

We recognized a curtailment gain of approximately $1 million on our defined benefit pension plan in the fourth quarter of 2004, as a substantial number of our current headquarters staff left the Company in this period.

Reorganization Items

For the year ended December 31, 2004, we recorded a net credit of $13 million related primarily to the settlement of obligations recorded under Fresh Start. We incurred $7 million of professional fees associated with the bankruptcy which offset $20 million of credits associated with creditor settlements. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred $2 million and $198 million, respectively, in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. Also see Item 15 Note 8 for a tabular description of expenses.

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, we recorded impairment charges of $45 million and $229 million for the year ended December 31, 2004 and the period January 1, 2003 through December 5, 2003, respectively, as shown in the table below. Of the $45 million total in 2004, Kendall and the Meriden turbine accounted for $27 million and $15 million, respectively. We successfully completed the sale of Kendall in November 2004 and expect to complete the sale of the Meriden turbines in 2006. There were no impairment charges for the period December 6, 2003 through December 31, 2003.

To determine whether an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value.

See Item 15 Note 8 for a list of impairment charges (credits) for the year ended December 31, 2004 and the period January 1, 2003 to December 5, 2003.

Restructuring Charges

We incurred $8 million of employee separation costs and advisor fees during the period January 1, 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

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Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in connection with fresh start adjustments. Following is a summary of the significant effects of the reorganization and Fresh Start:

		(In millions)
Discharge of corporate level debt	$	5,162
Discharge of other liabilities		811
Establishment of creditor pool		(1,040)
Receivable from Xcel		640
Revaluation of fixed assets		(1,392)
Revaluation of equity investments		(207)
Valuation of SO_2 emission credits		374
Valuation of out of market contracts, net		(400)
Fair market valuation of debt		108
Valuation of pension liabilities		(61)
Other valuation adjustments		(100)
Total Fresh Start adjustments		3,895
Less discontinued operations		(325)
Total Fresh Start adjustments continuing operations	$	4,220

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $463 million of legal settlement charges which consisted of the following. We recorded $396 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396 million under NRG Energy s Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60 million pre-petition bankruptcy claim and an $8 million post-petition bankruptcy claim. We had previously recorded approximately $11 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57 million during November 2003. In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we paid approximately $2 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian, therefore, we recorded an additional $1 million during November 2003.

Other Income (Expense)

Reorganized NRG

During the year ended December 31, 2004, we recorded other expense of $167 million. Other expense consisted primarily of $266 million of interest expense, $72 million of refinancing-related expenses, $16 million of write downs and losses on sales of equity method investments, offset by $160 million of equity in

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earnings of unconsolidated affiliates (including $69 million from our investment in West Coast Power LLC) and $27 million of other income, net.

Other income (expense) for the period December 6, 2003 through December 31, 2003, was an expense of $5 million and consisted primarily of $19 million of interest expense, partially offset by $14 million of equity in earnings of unconsolidated affiliates.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded other expense of $265 million. Other expense consisted primarily of $308 million of interest expense and $147 million of write downs and losses on sales of equity method investments, partially offset by equity in earnings of unconsolidated affiliates of $171 million and $19 million of other income, net.

Equity in Earnings of Unconsolidated Affiliates

Reorganized NRG

For the year ended December 31, 2004, we recorded $160 million of equity earnings from our investments in unconsolidated affiliates. Our equity in earnings of WCP comprised $69 million of this amount with our equity in earnings of Enfield, MIBRAG, and Gladstone comprising $28 million, $21 million, and $17 million, respectively. Our investment in WCP generated favorable results due to the pricing under the CDWR contract. Additionally, revenues from ancillary services revenue and minimum load cost compensation power positively contributed to WCP s operating results. However, our equity earnings in the project as reported in our results of operations have been reduced by a net $116 million to reflect a non-cash basis adjustment for in the money contracts resulting from adoption of Fresh Start.

NRG Energy s equity earnings were also favorably impacted by $23 million of unrealized gain related to our Enfield investment. This gain is associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

Equity in earnings of unconsolidated affiliates of $14 million for the period December 6, 2003 through December 31, 2003 consists primarily of equity earnings from our 50% ownership in WCP of $9 million.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $171 million of equity earnings from investments in unconsolidated affiliates. Our 50% investment in WCP comprised $99 million of this amount with our investments in the MIBRAG, Loy Yang, Gladstone and Rocky Road projects comprising $22 million, $18 million, $12 million and $7 million, respectively, with the remaining amounts attributable to various domestic and international equity investments.

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Equity in earnings of unconsolidated affiliates consists of the following:

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003
		(In millions)	
WCP	$ 69	$ 9	$ 99
MIBRAG	21		22
Enfield	28	1	6
Gladstone	17	1	12
Rocky Road	7		7
James River	8	1	(2)
NRG Saguaro	5	1	4
Scudder LA Trust	2		3
NRG National	1		2
Loy Yang			18
Other	2	1	
Total Equity in Earnings of Unconsolidated Affiliates	$ 160	$ 14	$ 171

Write Downs and Losses on Sales of Equity Method Investments

As part of our periodic review of our equity method investments for impairments, we have taken write downs and losses on sales of equity method investments during the year ended December 31, 2004 of $16 million and $147 million for the period January 1, 2003 through December 5, 2003. Our Commonwealth Atlantic Limited Partnership (CALP) and James River investments were written down based on indicative market bids. The sale of CALP closed in the fourth quarter of 2004, while the sale agreement for James River has been terminated. There were no write downs and losses on sales of equity method investments for the period December 6, 2003 through December 31, 2003.

Further details as to write downs and losses (gains) on sales of equity method investments recorded in the consolidated statement of operations are detailed in Item 15 Note 7 to the Consolidated Financial Statements.

Other Income, net

Reorganized NRG

During the year ended December 31, 2004, we recorded $27 million of other income, net, consisting primarily of interest income earned on notes receivable and cash balances. For the period December 6, 2003 through December 31, 2003 we recorded an immaterial amount of other income.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $19 million of other income, net. During this period other income, net consisted primarily of interest income earned on notes receivable and cash balances, offset in part by the unfavorable mark-to-market on our corporate level £160 million note that was cancelled in connection with our bankruptcy proceedings.

Interest Expense

Reorganized NRG

Interest expense for the year ended December 31, 2004 was $266 million, consisting of interest expense on both our project- and corporate-level interest-bearing debt. Significant amounts of our corporate-level debt were forgiven upon our emergence from bankruptcy and we refinanced significant amounts of our project-level debt with corporate level high yield notes and term loans in December 2003. Also included in interest expense is the amortization of debt financing costs of $9 million related to our corporate level debt and $13 million of amortization expense related primarily to debt discounts and premiums recorded as part of Fresh Start. Interest expense also includes the impact of any interest rate swaps that we have entered in order to manage our exposure to changes in interest rates.

Interest expense for the period December 6, 2003 through December 31, 2003 of $19 million consists primarily of interest expense at the corporate level, primarily related to the Second Priority Notes, term loan facility and revolving line of credit used to refinance certain project-level financings. In addition, interest expense includes the amortization of deferred financing costs incurred as a result of our refinancing efforts and the amortization of discounts and premiums recorded upon the marking of our debt to fair value upon our adoption of the Fresh Start provision of SOP 90-7.

Predecessor Company

Interest expense for the period January 1, 2003 through December 5, 2003 of $308 million consisted of interest expense on both our project and corporate level interest bearing debt. In addition, interest expense includes the amortization of debt issuance costs and any interest rate swap termination costs. Interest expense during this period was favorably impacted by our ceasing to record interest expense on debt where it was probable that such interest would not be paid, such as the NRG Energy corporate level debt (primarily bonds) and the NRG Finance Company debt (construction revolver) due to our entering into bankruptcy in May 2003. We did not however cease to record interest expense on the project-level debt outstanding at our Northeast Generating and South Central Generating facilities even though these entities were also in bankruptcy as these claims were deemed to be most likely not impaired and not subject to compromise. We also recorded substantial amounts of fees and costs related to our acquiring a debtor in possession financing arrangement while we were in bankruptcy. In addition, upon our emergence from bankruptcy we wrote off any remaining deferred finance costs related to our corporate and project-level debt including our Northeast and South Central project-level debt as it was probable that they would be refinanced upon our emergence from bankruptcy. Interest expense was unfavorably impacted by an adverse mark-to-market on certain interest rate swaps that we have entered in order to manage our exposure to changes in interest rates. Due to our deteriorating financial condition during such period, hedge accounting treatment was ceased for certain of our interest rate swaps, causing changes in fair value to be recorded as interest expense.

Refinancing Expense

Refinancing expense was $72 million for the year ended December 31, 2004. This amount includes $15 million of prepayment penalties and a $15 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with additional corporate level high yield notes in January 2004 and $14 million of prepayment penalties and a $27 million write-off of deferred financing costs related to refinancing the senior credit facility in December 2004.

Income Tax Expense

Reorganized NRG

Our income tax provision from continuing operations was $65 million for the year ended December 31, 2004 and an income tax benefit of ($1) million for the period December 6, 2003 through December 31, 2003. The overall effective tax rate in 2004 and the short period in 2003 was 28.7% and (6.2%), respectively. The change in our effective tax rate was primarily due to a state tax refund received from Xcel Energy in 2003 and foreign income taxed in jurisdictions with tax rates different from the U.S. statutory rate.

Our net deferred tax assets at December 31, 2004 were offset by a full valuation allowance in accordance with SFAS No. 109. Under SOP 90-7, any future benefits from reducing a valuation allowance from pre-confirmation deferred tax assets are required to be reported first as an adjustment of identifiable intangible assets and then as a direct addition to paid in capital versus a benefit on our statement of operations.

The effective tax rate may vary from year to year depending on, among other factors, the geographic and business mix of earnings and losses. These same and other factors, including history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Predecessor Company

Income tax expense for the period January 1, 2003 through December 5, 2003 was $38 million. The overall effective tax rate for the period ended December 5, 2003 was 1.3%. The rate is lower than the U.S. statutory rate primarily due to a release in valuation allowance for net operating loss carryforwards that were utilized following our emergence from bankruptcy to offset the current tax on cancellation of debt income.

Income taxes have been recorded on the basis that our U.S. subsidiaries and we would file separate federal income tax returns for the period January 1, 2003 through December 5, 2003. Since our U.S. subsidiaries and we were not included in the Xcel Energy consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes filed a separate federal income tax return. It is uncertain if, on a stand-alone basis, we would be able to fully realize deferred tax assets related to net operating losses and other temporary differences, therefore a full valuation allowance has been established.

Income From Discontinued Operations, net of Income Taxes

Reorganized NRG

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the year ended December 31, 2004, we recorded income from discontinued operations, net of income taxes, of approximately $25 million. During the year ended December 31, 2004 and for the period December 6, 2003 to December 31, 2003, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville), four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC), Northbrook New York LLC, Northbrook Energy LLC and Audrain Generating LLC. All other discontinued operations were disposed of in prior periods. The $25 million income from discontinued operations includes a gain of $22 million, net of income taxes of $8 million, related primarily to the dispositions of Batesville, Cobee and Hsin Yu.

Discontinued operations for the period December 6, 2003 through December 31, 2003 is comprised of a loss of less than a million dollars attributable to the on going operations of our McClain, PERC, Cobee, LSP Energy, Hsin Yu, four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC) and Audrain Generating LLC. The financial results of Northbrook New York LLC and Northbrook Energy LLC have not been reclassified as discontinued operations in the consolidated statement of operations and the consolidated statement of cash flows, for the period December 6, 2003 through December 31, 2003 due to immateriality.

Predecessor Company

As of December 5, 2003, we classified as discontinued operations the operations and gains/losses recognized on the sales of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the period January 1, 2003 through December 5, 2003, discontinued operations consist of the historical operations and net gains/losses related to our Killingholme, McClain, PERC, Cobee, NEO Landfill Gas, Inc., or NLGI, seven NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, NEO Ft. Smith LLC, NEO Woodville LLC and NEO Phoenix LLC), Timber Energy Resources, Inc., or TERI, Cahua, Energia Pacasmayo, LSP Energy, Hsin Yu projects and Audrain Generating LLC. Prior to December 6, 2003, Northbrook New York LLC and Northbrook NewYork LLC were unconsolidated affiliates because the ownership structure prevented us from exercising a controlling influence over operating and financial policies of the projects.

For the period January 1, 2003 through December 5, 2003, the results of operations related to such discontinued operations was a net loss of $316 million due to a net loss of results of operations from discontinued operations of Audrain Generating LLC of $133 million, loss on the sale of our Peru projects, impairment charges of $101 million and $24 million, respectively, recorded at McClain and NLGI and fresh start adjustments at LSP Energy.

Reorganization and Emergence from Bankruptcy

On May 14, 2003, we and 25 of our U.S. affiliates, filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code, or the Bankruptcy Code, in the United States Bankruptcy Court for the Southern District of New York, or the bankruptcy court.

On May 15, 2003, NRG Energy, PMI, NRG Finance Company I LLC, NRGenerating Holdings (No. 23) B.V. and NRG Capital LLC filed the NRG plan of reorganization. On November 24, 2003, the bankruptcy court issued an order confirming the NRG plan of reorganization, and the plan became effective on December 5, 2003. On September 17, 2003, we filed the Northeast/ South Central plan of reorganization in connection with our Northeast and South Central subsidiaries in Chapter 11. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central plan of reorganization and the plan became effective on December 23, 2003.

Financial Reporting by Entities in Reorganization under the Bankruptcy Code and Fresh Start

Between May 14, 2003 and December 5, 2003, we operated as a debtor-in-possession under the supervision of the bankruptcy court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of SOP 90-7.

For financial reporting purposes, the close of business on December 5, 2003, represents the date of emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

Predecessor Company	The Company, pre-emergence from bankruptcy
	The Company s operations prior to December 6, 2003
Reorganized NRG	The Company, post-emergence from bankruptcy
	The Company s operations from December 6, 2003- December 31, 2004

The implementation of the NRG plan of reorganization resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In connection with the emergence from bankruptcy, we adopted Fresh Start in accordance with the requirements of SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, the enterprise value of our company was allocated among our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS 141. Accordingly, we pushed down the effects of this allocation to all of our subsidiaries.

Under the requirements of Fresh Start, we have adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and

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liabilities to their estimated fair values, we determined that there was no excess reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS 109. The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations), which is reflected in the Predecessor Company s results of operations for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management s forecast of expected cash flows from our core assets. Management s forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a forward looking approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisors prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our NRG plan of reorganization provided for the issuance of 100,000,000 shares of NRG common stock to the various creditors resulting in a calculated price per share of $24.04. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and bankruptcy court s approval of the NRG plan of reorganization.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in the Predecessor Company s statement of operations for 2003, which includes the gain on the restructuring of equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG post-Fresh Start statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company s financial statements and are therefore not comparable in certain respects to the

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financial statements prior to the application of Fresh Start. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

	Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments	Consolidation	NRG December 6, 2003
			(In millions)		
Current Assets	$ 1,718	$ 614	$ 4	$ 6	$ 2,342
Non-current Assets	8,172	(155)	(1,233)	41	6,825
Total Assets	$ 9,890	$ 459	$ (1,229)	$ 47	$ 9,167
Current Liabilities	2,190	999	1,187	1	4,377
Non-current Liabilities	9,458	(6,270)	(848)	46	2,386
Total Liabilities	11,648	(5,271)	339	47	6,763
Stockholders Equity	(1,758)	2,404	1,758		2,404
Total Liabilities and Stockholders Equity	$ 9,890	$ (2,867)	$ 2,097	$ 47	$ 9,167

APB No. 18, *The Equity Method of Accounting for Investments in Common Stock,* requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee were a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate, we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power s California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the approximate amount of $116 million for the year ended December 31, 2004. This contract expired in December 2004.

Known trends that will affect our results in the future:

Acquisition of Texas Genco and Financing Transactions

On February 2, 2006, NRG acquired Texas Genco LLC by purchasing all of the outstanding equity interests in Texas Genco pursuant to the Acquisition Agreement, dated September 30, 2005, by and among NRG, Texas Genco, and the Sellers. Also see our detailed discussion in our Liquidity and Capital Resources section. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

In order to facilitate the acquisition of Texas Genco, we entered into a series of financing transactions. Also see our detailed discussion in our Liquidity and Capital Resources section:

Debt instruments:

$3.575 billion Term Loan Facility

$1.0 billion Revolving Credit Facility

$1.0 billion Letter of Credit Facility

$1.2 billion in aggregate principal amount of 7.25% Senior Notes

$2.4 billion in aggregate principal amount of 7.375% Senior Notes

Equity instruments:

$485 million from the issuance of 2 million shares of 5.75% Preferred Stock, net of issuance costs

$985 million from the issuance of 20,855,057 shares of our common stock, net of issuance costs

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These transactions also facilitated the refinancing of our outstanding debt as well as the debt outstanding for Texas Genco upon acquisition.

Based on our current projections, our NRG Texas segment will be a profitable segment and will significantly increase our revenue and operating costs going forward. Partially offsetting this additional profit will be the increased interest expense due to the increased debt level as shown above. We have also increased the number of our outstanding shares by issuing approximately 35 million shares from both treasury and newly issued stock to the Sellers, as well as approximately 21 million newly issued shares to the public. This significant increase in outstanding shares will dilute our future earnings per share.

At this time, we anticipate that the net effect in 2006 will be positive to our future results of operations as well as to our earnings per share.

Acquisition of Remaining 50% Equity Interest in WCP

On December 27, 2005, we entered into purchase and sale agreements for projects co-owned with Dynegy. Under the agreements, we will acquire Dynegy s 50% ownership interest in WCP (Generation) Holdings, Inc., and become the sole owner of WCP s 1,808 MW of generation in Southern California. We anticipate that the transaction will close during the first quarter of 2006.

As of the date of acquisition we will consolidate the results of operations of WCP. When consolidated, the results of WCP will increase our revenues and cost of operations, but it will reduce our equity earnings. We anticipate that the net effect in 2006 will be positive to our results of operations.

Liquidity and Capital Resources

Significant Events during 2005

- The repurchase of $645 million in aggregate principal amount of our Second Priority Notes, resulting in $54 million of refinancing charges
- The issuance of $250 million of 3.625% Preferred Stock
- The execution of the Accelerated Share Repurchase Agreement whereby we repurchased $250 million of common stock
- Repatriation of $298 million of foreign funds utilizing the tax benefits of the American Jobs Creation Act of 2004
- Cash collateral payments of $405 million supporting our hedging activities
- Collection of $71 million in an arbitration award related to TermoRio
- Execution of the Texas Genco Acquisition Agreement and related financing commitments
- Sale of non-core assets resulting in $106 million in proceeds
- The announced signing of sales and purchase agreements for the sale of Audrain resulting in its reclassification as a discontinued operation

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The following table summarizes the debt transactions during 2005 and subsequent transactions in 2006:

	Date of Transaction	Original Amount	Balance Outstanding at December 31, 2004	2005 activity and Outstanding at December 31, 2005	2006 activity and Outstanding at February 25, 2006
			(In millions)		
Xcel Promissory Note	Dec. 6, 2003	$ 10	$ 10	$ 10	$ 10
NRG 8% Second Priority Notes	Dec. 23, 2003- Jan. 28, 2004	1,725	1,725		
Repurchase of Notes	Jan-Mar, 2005			(41)	
Early redemption	Feb-Sep, 2005			(604)	
Ending balance Dec. 31, 2005				1,080	
Repurchase of Notes	Feb. 2, 2006				(1,080)
Ending balance Feb. 25, 2006					$
NRG Credit Facility Term loan	Dec. 23, 2003	950	450		
Repayments of Term Loans	Throughout 2005			(4)	
Ending balance Dec. 31, 2005				446	
Prepayment of Term Loan	Jan 2006				(446)
Ending balance Feb. 25, 2006					$
Letter of Credit facility	Dec. 23, 2003	250	350	350	
Terminating Letter of Credit facility	Feb. 2, 2006				(350)
Ending balance Feb. 25, 2006					$
Corporate Revolver*	Dec. 23, 2003	250	150	150	
Terminating Corporate Revolver*	Feb. 2, 2006				(150)
Ending balance Feb. 25, 2006*					$
New Sr. Secured Term loan	Feb. 2, 2006				3,575
New Funded LC Facility	Feb. 2, 2006				1,000

New Corporate Revolver*	Feb. 2, 2006			1,000
Ending balance Feb. 25, 2006				$ 5,575
7.25% Senior Notes due 2014	Feb. 2, 2006			1,200
7.375% Senior Notes due 2016	Feb. 2, 2006			2,400
Ending balance Feb. 25, 2006				$ 3,600
Total Corporate Level Debt*		$ 2,535	$ 1,886	$ 7,185

* Amount indicates capacity to borrow under NRG s revolver facilities only. Un-borrowed capacity is not included in total corporate level debt.

Sources of Funds

The principal sources of liquidity for our future operations and capital expenditures are expected to be existing cash on hand, cash flows from operations, and funds raised from new financing arrangements.

Cash Flows from Operations. Our operating cash flows are expected to be impacted by, among other things: (i) spark spreads generally; (ii) commodity prices (including demand for natural gas, coal, oil and electricity); (iii) the cost of ordinary course operations and maintenance expenses; (iv) planned and unplanned outages; (v) restrictions in the declaration or payments of dividends or similar distributions from our subsidiaries; and (vi) the timing and nature of asset sales. Following are additional sources of cash flows:

Letter of credit and revolver borrowing capacity. We had approximately $38 million of undrawn letter of credit capacity and $150 million of revolving credit capacity under our Amended Credit Facility as of December 31, 2005. On February 2, 2006 we terminated our Amended Credit Agreement and entered into a new Senior Credit Facility. The new Senior Credit Facility consists of a $3.575 billion term loan, $1.0 billion in a synthetic letter of credit facility and $1.0 billion in a revolver facility. Portions of the revolving credit facility are available as a swing-line facility and as a revolving letter of credit sub-facility. As of March 3, 2006, we had approximately $225 million of undrawn letter of credit capacity under our senior credit facility and $845 million of revolving credit capacity under our Senior Credit Facility. The balance of the revolver has been used to issue non-commercial letters of credit. See our discussion below on the Financing Transactions and Texas Genco Acquisition in this discussion and analysis.

Issuance of $250 million in 3.625% Preferred Stock. On August 11, 2005, we issued 250,000 shares of 3.625% Preferred Stock to Credit Suisse First Boston Capital LLC, or CSFB, in a private placement. As of December 31, 2005, 250,000 shares of the 3.625% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs of $246 million. Holders of the 3.625% Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available therefore, cash dividends at the rate of 3.625% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on December 14, 2005. On or after August 11, 2015, we may redeem, subject to certain limitations, some or all of the 3.625% Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date. Proceeds from the sale of the 3.625% preferred securities along with cash on hand were used to redeem $229 million in Second Priority Notes, pay an early redemption penalty of $18 million and pay accrued interest of $4 million on the redeemed notes.

Settlements and Asset Sales. On February 15, 2005 we received a $71 million settlement payment from Petrobras, our former partner in our TermoRio project in Brazil. During 2005, we received approximately $106 million in proceeds from the sale of our interest in non-core projects, including our interest in Enfield, Northbrook New York and Northbrook Energy and remaining interest in Kendall.

Repatriation of Foreign Funds. During the third quarter of 2005 we repatriated approximately $298 million of accumulated foreign earnings. Only a portion of this amount represents the cumulative earnings and profits from the foreign entities. Those earnings resulted in approximately $5 million of tax expense. This repatriation was initiated to utilize the tax benefits of the American Jobs Creation Act of 2004 which expired on December 31, 2005.

Uses of Funds

Our requirements for liquidity and capital resources, other than for operating our facilities, can generally be categorized by the following: (i) Commercial Operations (formerly referred to as PMI) activities; (ii) capital expenditures; (iii) corporate financial restructuring and (iv) project finance requirements.

(i) Commercial Operations

Commercial Operations activities comprise the single largest requirement for liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counter-parties; (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, 2005, Commercial Operations had total cash collateral outstanding of $438 million, and $227 million outstanding in letters of credit to third parties primarily to support our economic hedging activities.

Future liquidity requirements may change based on our hedging activity, fuel purchases, future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on our credit ratings and general perception of creditworthiness.

Following the Acquisition, our debt instruments permit us to grant secured priority liens on our assets to support certain trading activities which will provide an alternative to posting cash deposits and letters of credit. See our discussion below on the Financing Transactions and Texas Genco Acquisition in this discussion and analysis.

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(ii) Capital Expenditures

Capital expenditures were $106 million for the year ended December 31, 2005, and $119 million for the year ended December 31, 2004. Capital expenditures in 2005 related to the continued PRB conversions, associated conveyor track and emissions compliance upgrades at our Western New York plants. Indian River s PRB conversion is underway at units 1-3. Unit 4 at Indian River, originally targeted for conversion, was deemed incompatible for PRB coal during 2005. Capital expenditures in 2004 also related primarily to the conversion of our western New York plants to PRB coal, as well as the Playford 2 refurbishment at our Flinders operation in Australia and planned outages across our fleet.

(iii) Corporate Financial Restructuring

Repurchase and redemption of Second Priority Notes during 2005. In conjunction with our goal of improving our credit ratings we manage our capital allocation around a target of 45%-60% debt to capital ratio. As such, we may elect periodically to modify our corporate financial structure. Throughout 2005, we repurchased or redeemed, and subsequently retired, $645 million of our Second Priority Notes. Total costs associated with the repurchase and redemptions was $52 million in early redemption premium, $9 million in accrued but unpaid interest, and $7 million in accrued but unpaid liquidated damages.

Redemption of Second Priority Notes and Termination of Credit Facility during 2006. On January 31, 2006 we repaid $446 million in outstanding principal plus $3 million in accrued interest and terminated our term loan under our Amended Credit Facility. On February 2, 2006, we repurchased and retired $1.08 billion of our Second Priority Notes, pursuant to a tender offer, paying approximately $138 million in consent premiums and accrued interest. On February 2, 2006 we defeased the remaining un-tendered $0.4 million of our Second Priority Notes, effectively terminating our obligations with respect to such Notes. Also on February 2, 2006 we paid $1 million in accrued fees and terminated our revolving facility and our funded letter of credit facility under our Amended Credit Facility, and simultaneously issued new indebtedness, as described below in *New Financing Structure and Texas Genco Acquisition* in this discussion and analysis.

Accelerated Share Repurchase Plan. On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement with CSFB, pursuant to which we repurchased $250 million of our common stock on that date that equaled a total of 6,346,788 shares, which were held in treasury. We funded the repurchase with cash on hand. On March 3, 2006, we paid to CSFB a cash purchase price adjustment of approximately $7 million based upon the weighted average value of NRG s common stock over a period of approximately six months, subject to a minimum price of 97% and a maximum price of 103% of the closing price per share on August 10, 2005, or $39.39.

Preferred Dividend Payments. During 2005, we paid approximately $17 million in four dividend payments to our holders of our 4% Preferred Stock. On December 15, 2005, we made an approximate $3 million dividend payment to our 3.625% preferred shareholders of record as of December 1, 2005.

(iv) Project Finance Requirements

We are a holding company and conduct our operations primarily through subsidiaries. Historically, we have utilized project-level debt to fund a significant portion of the capital expenditures and investments required to construct our power plants and related assets. Consistent with our strategy, we may seek, where available on commercially reasonable terms, project-level debt in connection with the assets or businesses of our affiliates, or we may develop, construct or acquire new projects. Project-level borrowings are substantially non-recourse to other subsidiaries, affiliates and us, and are generally secured by the capital stock, physical assets, contracts and cash flow of the related project subsidiary or affiliate being financed. Some of these project financings may require us to post collateral in the form of cash or an acceptable letter of credit.

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Principal on short-term debt, long-term debt and capital leases as of December 31, 2005 are due and payable in the following periods (in millions):

Subsidiary/Description	Total	2006	2007	2008	2009	2010	Thereafter
Xcel Energy Note	$ 10	$ 10	$	$	$	$	$
Amended Credit Facility due Dec. 2011	796	796					
8% Second Priority Notes	1,080	1,080					
NRG Energy Center Minneapolis, due 2013 and 2017	111	8	9	10	11	11	62
NRG Peaker Finance Co LLC	297	7	11	13	15	20	231
Flinders Power Finance Pty	177	6	14	4	8	18	127
Camas Pwr BLR LP Bank facility	4	3	1				
Camas Pwr BLR LP Bonds	3	1	2				
Itiquira Energetica S.A., due January 2012	19	3	3	3	3	3	4
Itiquira Energetica S.A., due December 2013	30	4	4	4	4	4	10
Subtotal Debt, Bonds and Notes	2,527	1,918	44	34	41	56	434
Saale Energie GmbH, Schkopau (capital lease)	214	61	34	28	21	10	60
Conemaugh Fuels LLC (capital lease)							
Subtotal Capital Leases	214	61	34	28	21	10	60
Total Debt	$ 2,741	$ 1,979	$ 78	$ 62	$ 62	$ 66	$ 494

These amounts reflect scheduled amortization of principal as of December 31, 2005, with the exception of the 8% Second Priority Notes, and our Credit Facility, for which 2006 amounts reflect early termination. The table below reflects the new short-term and long-term debt amounts and the expected future payments. Also see our discussion below on the Financing Transactions and Texas Genco Acquisition in this discussion and analysis, as well as Item 15 Note 17 to the Consolidated Financial Statements for further discussion on events that may affect debt payment schedules.

Description	Total	2006	2007	2008	2009	2010	Thereafter
New Credit Facility due Feb 2013	$ 3,575	$ 26	$ 36	$ 36	$ 36	$ 36	$ 3,405
7.25% Notes due 2014	1,200						1,200
7.375% Notes due 2016	2,400						2,400
Total Debt	$ 7,175	$ 26	$ 36	$ 36	$ 36	$ 36	$ 7,005

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Historical Cash Flows

We have obtained cash from operations, proceeds from repayment of outstanding notes receivable, proceeds from the sale of certain assets and the proceeds from the sale of preferred stock. We have used these funds to finance operations, reduce our outstanding Second Priority Notes, repurchase common stock through an accelerated share repurchase plan, service debt obligations, finance capital expenditures, and meet other cash and liquidity needs. The following table reflects the changes in cash flows for the comparative years and we include a detailed discussion on the changes during the last year. All cash flow categories include the cash flows from continuing operations and discontinued operations:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6- December 31, 2003	For the Period January 1- December 5, 2003
	(In millions)			
Net cash provided (used) by operating activities	$ 68	$ 645	$ (589)	$ 238
Net cash (used) provided by investing activities	158	184	363	(186)
Net cash provided (used) by financing activities	(830)	(284)	393	(30)

Net Cash Provided (Used) By Operating Activities

For the year ended December 31, 2005, net cash provided by operating activities decreased by $580 million compared to the year ended December 31, 2004. This is primarily due to the following reasons:

Net income decreased by $102 million for the year ended December 31, 2005 compared to the year ended December 31, 2004.

Due to the sharp increase in the sale price per MWh, our derivative contract terms required collateral deposits of $405 million during 2005, compared to $7 million during 2004, a difference of $398 million. As of December 31, 2005 we had collateral deposits of $438 million and we expect $405 of this amount to be refunded during 2006 as the underlying contracts expire.

A decrease of $60 million in distributions from our equity investments during 2005 compared to 2004. The majority of this decrease is from our WCP investment. Since the expiration of the CDWR contract on December 31, 2004, WCP s profit has been significantly reduced and has subsequently distributed $59 million less dividends during 2005 compared to 2004.

Receipt of $100 million in 2004 related to the settlement with Xcel Energy.

Net Cash Provided (Used) By Investing Activities

For the year ended December 31, 2005, net cash provided by investing activities was $26 million less than for the year ended December 31, 2004. This decrease is due to the following mix of investment activities:

During 2004, we sold interests in non-core assets for proceeds totaling $304 million. As most of the non-core assets were sold during 2004 and management began focusing on different areas of operation, during 2005 proceeds from the sale of non-core assets fell by $198 million.

Our capital expenditures were $13 million less during 2005 compared to 2004 due to lower PRB conversion expenditures.

During 2005, proceeds from payments on our notes receivable increased by $82 million, primarily due to the payment from TermoRio of approximately $71 million as the dispute related to this note was settled.

In comparison to an increase of $27 million during 2004, restricted cash balances decreased by $46 million, a difference of $72 million. This amount is explained by the release of approximately $38 million of restricted cash at our Flinders facility as a result of our refinancing of Flinders debt, as well as the release of accounts from restrictions during post bankruptcy operations.

Net Cash Provided (Used) By Financing Activities

For the year ended December 31, 2005, net cash used by financing activities increased by $546 million in comparison to 2004. The activity for 2005 consisted of:

The redemption and repurchase of $645 million of our Second Priority Secured Notes. In order to redeem our Second Priority Notes, we issued $420 million of the 4% Preferred Stock in December 2004, and subsequently, $250 million of the 3.625% Preferred Stock in August of 2005. The timing difference between the receipt of cash from our 4% Preferred Stock in December 2004 and the redemption of debt in 2005 is the primary reason for the increase in cash used for financing activities in 2005 in comparison to 2004.

Our accelerated share repurchase payment of $250 million.

Payment of $46 million for financing costs to refinance our Flinders debt.

Payment of $20 million of dividends to holders of our preferred stock.

During 2004, the primary use of funds for financing activities was related to the repayment of project level debt at McClain of approximately $157 million and regular debt payments of approximately $135 million.

Other Liquidity Matters NOLs and Deferred Tax Assets

As of December 31, 2005, we U.S. NOL carryforwards of approximately $93 million. We believe that it is more likely than not that the benefit will not be realized on a substantial portion of the deferred tax assets relating to future tax benefits. This assessment includes consideration of positive and negative factors, including our current financial position, historical results of operations and current results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of December 31, 2005, a consolidated valuation allowance of $756 million was recorded against the net deferred tax assets, in accordance with SFAS No. 109. However, we have not provided a valuation allowance for approximately $15 million of net deferred tax assets which consist of mark-to-market adjustments per SFAS 133 and utilization of carryover net operating losses to the extent of taxable income generated for the year ended December 31, 2005.

Conclusion on Future Liquidity

As of December 31, 2005 our liquidity was $758 million and included $570 million of unrestricted and restricted cash. Our liquidity also included $150 million of available capacity under our revolving line of credit and $38 million of availability under our letter of credit facility. As of December 31, 2004 our liquidity was $1.6 billion and included $1.2 billion of unrestricted and restricted cash. Our liquidity also included $150 million of available capacity under our revolving line of credit and $193 million of availability under our letter of credit facility.

Based on the new financing transactions, but assuming the cash balances as of December 31, 2005 and the outstanding instruments as of March 3, 2006, our liquidity would be $1.6 billion and includes $570 million of unrestricted and restricted cash. Our liquidity include $845 million of available capacity under our new Revolving Credit Facility and $225 million of availability under our new synthetic Letter of Credit Facility, as of March 3, 2006. Please see discussion below for further detail.

Management believes that these amounts and cash flows from operations will be adequate to finance capital expenditures, to fund dividends to our preferred shareholders and other liquidity commitments for the next 12 months. 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 debt to capital ratio within a range of 45%-60%.

Known Trends and Other Factors Affecting our Liquidity

New Financing Structure and Texas Genco Acquisition

On February 2, 2006, NRG acquired Texas Genco LLC, a Delaware limited liability company, by purchasing all of the outstanding equity interests in Texas Genco pursuant to the Acquisition Agreement, dated September 30, 2005, by and among NRG, Texas Genco, and each of the direct and indirect owners of Texas Genco. The purchase price of approximately $6.1 billion consisted of $4.4 billion in cash and the issuance of approximately 35.4 million shares of NRG s common stock valued at $1.7 billion. This amount is subject to adjustment due to acquisition costs. The value of our common stock issued to the Sellers was based on our average stock price immediately before and after the closing date of February 2, 2006. The Acquisition includes the assumption of approximately $2.7 billion of Texas Genco debt. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

The Texas Genco acquisition was partially funded at closing with the combination of (i) cash proceeds received upon the issuance and sale in a public offering of 20,855,057 shares of NRG s common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $3.6 billion of unsecured high yield notes; (iii) cash proceeds received upon the issuance and sale in a public offering of 2,000,000 shares of mandatory convertible preferred stock at a price of $250 per share; (iv) funds borrowed under a new senior secured credit facility consisting of a $3.575 billion term loan facility, a $1.0 billion revolving credit facility and a $1.0 billion synthetic letter of credit facility; and (v) cash on hand.

Texas Genco owns approximately 11,000 MW of net operating generation capacity, and sells power and related services in the Texas ERCOT market.

New Senior Credit Facility

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

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

The New Senior Credit Facility is also secured by a first-priority perfected security interest in all of the property and assets owned at-any time or acquired by us and our subsidiaries, other than certain limited

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exceptions. These exceptions include assets such as the assets of certain unrestricted subsidiaries, equity interests in certain of our project affiliates that have non-recourse debt financing, and voting equity interests in excess of 66% of the total outstanding voting equity interest of certain of our foreign subsidiaries.

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

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

Senior Notes

On February 2, 2006, we completed the sale of (i) $1.2 billion in aggregate principal amount of 7.25% senior notes due 2014, or 7.25% Senior Notes, and (ii) $2.4 billion in aggregate principal amount of 7.375% senior notes due 2016, or 7.375% Senior Notes, collectively the Senior Notes. The Senior Notes were issued under an Indenture, dated February 2, 2006, between us and Law Debenture Trust Company of New York, as Trustee, as supplemented by a First Supplemental Indenture, dated February 2, 2006, between us, the guarantors named therein and the Trustee, relating to the 7.25% Senior Notes, and as supplemented by a Second Supplemental Indenture, dated February 2, 2006,(together with the Indenture and the First Supplemental Indenture, the Indentures) between us, the guarantors named therein and the Trustee, relating to the 7.375% Senior Notes. The Indentures provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG.

Interest is payable on the Senior Notes on February 1 and August 1 of each year beginning on August 1, 2006 until their maturity dates February 1, 2014 for the 7.25% Senior Notes and February 1, 2016 for the 7.375% Senior Notes.

Prior to February 1, 2010 for the 7.25% Senior Notes and prior to February 1, 2011 for the 7.375% Senior Notes, we may redeem all or a portion of the series of Senior Notes at a price equal to 100% of the principal amount plus a make whole premium and accrued interest. On or after February 1, 2010 for the 7.25% Senior Notes and on or after February 1, 2011 for the 7.375% Senior Notes, we may redeem all or a portion of the series of Senior Notes at redemption prices set forth in the Indentures. In addition, at any time prior to February 1, 2009, we may redeem up to 35% of the aggregate principal amount of the series of Senior Notes with the net proceeds of certain equity offerings at the redemption price set forth in the Indentures.

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

- make restricted payments;
- restrict dividends or other payments of subsidiaries;
- incur additional debt;
- engage in transactions with affiliates;

create liens on assets;

engage in sale and leaseback transactions; and

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

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

Second Lien Structure

Before the Acquisition, Texas Genco s capital structure permitted the grant of second priority liens on its assets as security for their obligations under certain long-term power sales agreements and related hedges. The Credit Agreement for New Senior Credit Facility and the Indentures, which became effective as of February 2, 2006, allow these arrangements to remain in place. In addition, the new debt instruments also permit us to grant second priority liens on our other assets in the United States in order to secure obligations under power sales agreements and related hedges, within certain limits. The seven trading counterparties of Texas Genco who held second priority liens on Texas Genco s assets as of February 2, 2006, have been offered a second priority lien on NRG s other assets under the new structure, as additional collateral. Going forward, NRG anticipates that it will use the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under long term power sales and related hedges. Also see Item 1 Business section within the Power Marketing and Commercial Operations discussion for quantified utilization as of December 31, 2005.

Mandatory Convertible Preferred Stock

On February 2, 2006, we completed the issuance of 2 million shares of 5.75% mandatory convertible preferred stock, or the 5.75% Preferred Stock, at an offering price of $250 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $485 million. Dividends on the 5.75% Preferred Stock are $14.375 per share per year, and are due and payable on a quarterly basis beginning on March 15, 2006. The 5.75% Preferred Stock will automatically convert into common stock on March 16, 2009, or the Conversion Date, at a rate that is dependent upon the applicable market value of our common stock. If the applicable market value of our common stock is $60.45 a share or higher at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 4.1356 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is less than or equal to $48.75 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 5.1282 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is between $48.75 per share and $60.45 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible into common stock at a rate that is between 4.1356 per share and 5.1282 per share of common stock.

Common Stock

On January 31, 2006, we completed the issuance of 20,855,057 shares of our common stock at an offering price of $48.75 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $985 million.

Sale of Audrain

Audrain has an approximate total of $355 million in long and short-term debt. We anticipate that the sale of Audrain will close during the first half of 2006 upon which these balances will be eliminated.

Brownfield Developments

As part of our strategy to reinvest capital in our existing assets for reason of repowering and expansion of current generation sites, management is evaluating opportunities within our core areas of operations.

During the third quarter, we received a Title V Air Permit from the Louisiana Department of Environmental Quality to add a fourth unit of generating capacity at our Big Cajun II Generating Station in New Roads, Louisiana. The total capital expenditure expected from the construction of the 675 MW expansion project is approximately $1 billion and would take four years to build. Our Big Cajun II facility serves the electricity needs of Louisiana s 11 electric cooperatives and we believe that there is additional unmet demand for coal-fired generation in the area. We are currently evaluating potential partners and customers for this project as they are critical to the consideration of when to proceed with this project.

Operations in Australia

NRG is currently considering strategic alternatives with respect to Australia either to reposition its assets more effectively within the National Electricity Market or to monetize its investment. We will seek to determine the best option to optimize our investment during 2006.

Off-Balance Sheet Items

Obligations Under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 29, Guarantees and Other Contingent Liabilities for further details of the guarantee arrangements.

Retained or Contingent Interests

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

Derivative Instrument obligations

On August 11, 2005 NRG issued the 3.625% Preferred Stock which includes a conversion feature which is considered a derivative per FAS 133. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of SFA 133. Despite this exclusion, per the guidance of EITF Topic D-98 the conversion feature must be marked-to-market. Currently, the conversion feature is valued at $0 as our stock price is outside the conversion range. See Note 18 Capital Structure for further discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments

As of December 31, 2005, we have not entered into any financing structure that is designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to us. However, we have numerous investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting. Our pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $178 million and $252 million as of December 31, 2005 and December 31, 2004, respectively. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to us. In the normal course of business we may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates.

New Synthetic Letter of Credit Facility and Revolver Facility

Under the New Senior Credit Facility we entered into on February 2, 2006, we have a $1.0 billion synthetic Letter of Credit Facility that is unfunded directly by NRG, and a $1.0 billion senior Revolving Credit Facility. The synthetic Letter of Credit Facility is secured by a $1.0 billion cash collateral deposit, held by Deutsche Bank AG, New York Branch as the Issuing Bank. Under the synthetic Letter of Credit Facility, we are allowed to issue letters of credit to support our obligations under commodity hedging or power purchase arrangements. We are permitted to issue up to $300 million in unfunded letters of credit under our Revolving Credit Facility for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the New Senior Credit Facility, or revolver letters of credit.

As of March 3, 2006, we had issued $775 million in funded letters of credit under the Letter of Credit Facility. Of this amount, a portion was issued to support obligations under terminated NRG and Texas Genco letter of credit facilities. As of March 3, 2006, we had issued $155 million in revolver letters of credit, a portion of which supports non-commercial letter of credit obligations under the terminated NRG and Texas Genco letters of credit facilities.

Contractual Obligations and Commercial Commitments

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in Item 15 Notes 17 and 25 to the Consolidated Financial Statements.

	Payments Due by Period as of December 31, 2005				
Contractual Cash Obligations	**Total**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In millions)		
Long-term debt (including estimated interest)	$ 3,600	$ 201	$ 391	$ 408	$ 2,600
Capital lease obligations (including estimated interest)	406	77	90	52	187
Operating leases	150	25	37	27	61
Coal purchase and transportation obligations	416	192	154	52	18
Total contractual cash obligations	$ 4,572	$ 495	$ 672	$ 539	$ 2,866

	Amount of Guarantee Liabilities Expiration per Period as of December 31, 2005				
Guarantee Type	**Total Amounts Committed**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In millions)		
Funded standby letters of credit	$ 312	$ 312	$	$	$
Unfunded standby letters of credit	9	9			
Surety bonds	4	4			
Asset sales guarantee obligations	123		13		110
Commodity sales guarantee obligations	91	62	12	14	3

Other guarantees	91		1		90
Total guarantees	$ 630	$ 387	$ 26	$ 14	$ 203

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs, as discussed in Item 15

Note 25, *Commitments and Contingencies*, to the Consolidated Financial Statements for a discussion of commitments and contingencies that also include contractual obligations and commercial commitments that occurred during 2005.

Derivative Instruments

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

The tables below disclose the trading activities that include non-exchange traded contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at December 31, 2005 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2005.

Derivative Activity Gains/(Losses)

	(In millions)
Fair value of contracts at December 31, 2004	$ (43)
Contracts realized or otherwise settled during the period	129
Changes in fair value	(490)
Fair value of contracts at December 31, 2005	$ (404)

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts as of December 31, 2005				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
			(In millions)		
Prices actively quoted	$ (243)	$ (12)	$	$	$ (255)
Prices based on models and other valuation methods	2	(22)	(10)	(38)	(68)
Prices provided by other external sources	(53)	(1)	6	(33)	(81)
Total	$ (294)	$ (35)	$ (4)	$ (71)	$ (404)

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

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or GAAP, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges. These judgments, in and of

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themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, we evaluate our estimates, utilizing historic experience, consultation with experts and other methods we consider reasonable. In any case, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Our significant accounting policies are summarized in Item 15 Note 2 to the Consolidated Financial Statements. We identify our most critical accounting policies as those that are the most pervasive and important to the portrayal of our 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
Revenue Recognition and Derivative Activity	Assumptions used in valuation models Market maturity and economic conditions Contract interpretation Market conditions in the energy industry, especially the effects of price volatility on contractual commitments Documentation requirements Market conditions in foreign countries Regulatory and political environments and requirements
Income Taxes and Valuation Allowance for Deferred Tax Assets	Ability of tax authority decisions to withstand legal challenges or appeals Anticipated future decisions of tax authorities Application of tax statutes and regulations to transactions. Ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods.
Impairment of Long Lived Assets	Recoverability of investment through future operations Regulatory and political environments and requirements Estimated useful lives of assets Environmental obligations and operational limitations Estimates of future cash flows Estimates of fair value (fresh start) Judgment about triggering events
Goodwill and Other Intangible Assets	Estimated useful lives for finite-lived intangible assets Judgment about impairment triggering events Estimates of reporting unit s fair value Fair value estimate of certain power sales and fuel contracts using forward pricing curves as of the closing date over the life of each contract
Contingencies	Estimated financial impact of event(s) Judgment about likelihood of event(s) occurring

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Revenue Recognition and Derivative Instruments

We record revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting, including the application of hedge accounting, in more detail in Note 2 to the Consolidated Financial Statements. In January 2001, we adopted SFAS 133, as amended by SFAS 137, SFAS 138 and SFAS 149. SFAS 133, as amended, requires us to mark-to-market all derivatives on the balance sheet. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. 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 for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings.

Derivative instruments valuation assets and liabilities consist of a combination of energy and energy-related derivative contracts. While some of these contracts 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 modeling techniques to determine expected future market prices, contract quantities, or both. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate third party experts in determining the fair value of these derivatives. However, future market prices and actual quantities will vary from those used in recording derivative instruments valuation assets and liabilities, and it is possible that such variations could be material.

Income Taxes and Valuation Allowance for Deferred Tax Assets

At December 31, 2005, we had a valuation allowance of approximately $756 million primarily related to our U.S. net deferred tax assets. In assessing the recoverability of our deferred tax assets, we consider 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 the demonstration of a history of earnings and generation of future income during the periods in which those temporary differences will be deductible.

As of December 31, 2005, we have approximately $93 million of U.S. federal and state net operating loss (NOLs) carryforwards for financial reporting purposes. The ultimate utilization of our NOLs will depend on several factors, such as our ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods, the application of tax statutes and regulations to transactions, the ability of tax authority decisions to withstand legal challenges or appeals, and anticipated future decisions of tax authorities.

We continue to be under audit for multiple years by taxing authorities in other jurisdictions. Considerable judgment is required to determine the tax treatment of a particular item that involves interpretations of complex tax laws. A tax liability has been recorded for certain tax filing positions where our inability to sustain the tax return position is probable and estimable. Such liabilities are based on management s judgment which considers the best estimate of the amount and probable outcome of the tax position, and it can take several years between the time when a liability is recorded and when the related filing position is resolved with the taxing authority. Management periodically reviews these matters and adjusts the liabilities recorded on the financial statements as appropriate.

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

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

Significant decrease in the market price of a long-lived asset;

Significant adverse change in the manner an asset is being used or its physical condition;

Adverse business climate;

Accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,

Current-period loss combined with a history of losses or the projection of future losses;

Change in our 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 us. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We use our best estimates in making these evaluations and consider 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 our estimates, and the impact of such variations could be material.

For assets to be held and used, if we determine that the undiscounted cash flows from the asset are less than the carrying amount of the asset, we must estimate fair value to determine the amount of any impairment loss. Assets held for sale are reported at the lower of the carrying amount or fair value less the cost to sell. The estimation of fair value under SFAS No. 144, whether in conjunction with an asset to be held and used or with an asset held for sale, and the evaluation of asset impairment are, by their nature, subjective. We consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers, or employ other valuation techniques. We also will 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 our estimates, and the impact of such variations could be material.

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

For the years ended December 31, 2005 and December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 net income from continuing operations was reduced by $6 million, $45 million, $0 million and $229 million, respectively, due to investment impairments.

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Goodwill and Other Intangible Assets

As part of the Acquisition we expect to record intangible assets that may include goodwill resulting from the Acquisition and other intangible assets. We will apply SFAS 141, and SFAS 142 Goodwill and Other Intangible Assets, to account for these intangibles. Under these standards we will amortize all finite-lived intangible assets over their respective estimated weighted-average useful life, whereas goodwill and other intangibles that have indefinite lives are not amortized. However, goodwill and all intangible assets will be tested for impairment whenever an event occurs that indicates that an impairment may have occurred, or at a minimum on an annual basis. If necessary, our goodwill and/or intangible asset will be impaired at that time.

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

Contingencies

We record 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. We describe in detail our contingencies in Note 25 to the Consolidated Financial Statements.

Recent Accounting Developments

See Note 2 to the Consolidated Financial Statements as found in Item 15 for a discussion of recent accounting developments.

Item 7A ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with our merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to are commodity price risk, interest rate risk and currency exchange risk. In order to manage these risks we utilize 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 our fixed-price purchase and sales commitments;
- Manage and hedge our exposure to variable rate debt obligations,
- Reduce our exposure to the volatility of cash market prices; and
- Hedge our fuel requirements for our generating facilities.

Commodity Price Risk

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

- Seasonal daily and hourly changes in demand
- Extreme peak demands due to weather conditions

Available supply resources

Transportation availability and reliability within and between regions

Changes in the nature and extent of federal and state regulations

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

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

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

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

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

	(In millions)
Year end December 31, 2005	$ 36.9
Average	27.6
High	45.9
Low	16.0
Year end December 31, 2004	26.7
Average	40.3
High	53.4
Low	26.7

In order to provide additional information for comparative purposes to our peers we also utilize value at risk to model the estimate of potential loss of financial derivative instruments included in derivative instruments valuation assets and liabilities. This estimation includes those energy contracts accounted for as a hedge under SFAS 133, as amended. The estimated maximum potential loss in fair value of the financial derivative instruments calculated using the diversified VAR model as of December 31, 2005 is approximately $37 million.

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

Interest Rate Risk

We are exposed to fluctuations in interest rates through our issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

In January 2006, we entered into a series of new interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, we pay our counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we receive quarterly the equivalent of a floating interest payment based on 3-month LIBOR calculated on the same notional value. All payments by us and our counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of February 25, 2006 was $2.15 billion. The notional amounts and maturities of each tranche of these swaps are as follows:

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

As of December 31, 2005, we and our consolidating subsidiaries had various interest rate swap agreements with notional amounts totaling approximately $1.2 billion. If the swaps had been discontinued on December 31, 2005, we would have owed the counter-parties approximately $33.1 million. Based on the investment grade rating of the counterparties, we believe that our exposure to credit risk due to nonperformance by the counterparties to our hedging contracts is insignificant.

We have both long and short-term debt instruments that subject us to the risk of loss associated with movements in market interest rates. As of December 31, 2005, a 100 basis point change in interest rates would result in a $8.3 million change in interest expense on a rolling 12 month basis. When our new senior unsecured notes and new credit agreement are included, a 100 basis point change in interest rates would result in a $34 million change in interest expense on a rolling 12 month basis.

At December 31, 2005, the fair value of our fixed-rate long-term debt was $2.8 billion, compared with the carrying amount of $2.7 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our fixed-rate long-term debt by approximately $33 million. When our new senior unsecured notes and new credit agreement are included, we estimate that a 1% decrease in market rates would increase the fair value of our fixed rate long term debt by approximately $456 million.

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Liquidity Risk

Our collateral posted in support of our management of our electric generation facilities fluctuates based on amount of the portfolio hedged using collateralized contracts and market price movements. Based on a sensitivity analysis a $1 per MWh increase or decrease in electricity prices would cause a change in margin collateral outstanding of approximately $13 million. This sensitivity uses simplified assumptions and may not reflect actual market movements.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. We monitor and manage the credit risk of NRG and its subsidiaries through credit policies which include an (i) established credit approval process, (ii) daily monitoring of counter-party credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We have credit protection within various agreements to call on additional collateral support if necessary. As of December 31, 2005, we held collateral support of approximately $205 million from counterparties.

A portion of our credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities as of December 31, 2005:

	Exposure Before Collateral	Collateral	Net Exposure
		(In millions)	
Investment grade	$ 518	$ 96	$ 422
Non-investment grade	24	5	19
Not rated	164	25	139
Total	$ 706	$ 126	$ 580
Investment grade	73%	76%	73%
Non-investment grade	3%	4%	3%
Not rated	24%	20%	24%

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

NRG s exposure to significant counterparties greater than 10% of the net exposure of approximately $580 million was approximately $386 million as of December 31, 2005. We do not anticipate any material adverse effect on its financial position or results of operations as a result of nonperformance by any of its counterparties.

Currency Exchange Risk

We expect to continue to be subject to currency risks associated with foreign denominated distributions from our international investments. In the normal course of business, we may receive distributions denominated in the Euro, Australian Dollar and the Brazilian Real. We have historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to

the extent required, fixing the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. We would expect to enter into similar transactions in the future if management believes it to be appropriate.

As of December 31, 2005, neither we, nor any of our consolidating subsidiaries, had any material outstanding foreign currency exchange contracts.

Item 8 ***Financial Statements and Supplementary Data***

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

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

None.

Item 9A ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

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

There have not been any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter that have materially affected, or are reasonably likely to materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B ***Other Information***

Effective March 3, 2006, NRG entered into a restated employment agreement with David Crane, pursuant to which Mr. Crane will continue to serve as the Company s President and Chief Executive Officer. The initial term of the restated employment agreement will end on December 31, 2008, but the agreement provides for automatic extensions for additional successive one-year terms on the same terms and conditions, unless either party provides the other with notice to the contrary at least 90 days prior to the end of the initial term or any subsequent one-year term. The restated employment agreement provides for an initial annual base salary of $1,000,000. For each one-year period thereafter, Mr. Crane s base salary will be reviewed and may be increased by the Board. Beginning with the 2006 fiscal year, Mr. Crane is entitled to an annual bonus with a target amount of up to 100 percent of his base salary, based upon the achievement of criteria determined at the beginning of the fiscal year by the Board, with input from Mr. Crane, for that fiscal year. In addition, beginning with the 2006 fiscal year, Mr. Crane is entitled to a maximum annual bonus equal to up to an additional 100 percent of his base salary, based upon the achievement of criteria determined at the beginning of the fiscal year by the Board, with input from Mr. Crane, for that fiscal year. Mr. Crane is also eligible to participate in the Long Term Incentive Plan in accordance with its terms and is entitled to receive other customary fringe benefits generally available to the Company s executive employees. Mr. Crane is also entitled to certain severance benefits. Further details of Mr. Crane s employment package are set forth in the restated employment agreement attached as Exhibit 10.33 to this Form 10-K and incorporated herein by reference.

The Compensation Committee s and the Board of Director s approval of the Annual Incentive Plan Payout, or the AIP Payout, for each executive officer of NRG who is expected to be a named executive officer in NRG s Proxy Statement for the annual meeting of stockholders to be held on April 28, 2006 became final on March 7, 2006. The named executive officers include: David Crane, President and Chief Executive Officer;

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Robert C. Flexon, Executive Vice President and Chief Financial Officer; Kevin Howell, Executive Vice President, Commercial Operations; John P. Brewster, Executive Vice President, International Operations and President, South Central Region; and Christine A. Jacobs, Vice President, Plant Operations. Effective January 3, 2006, the Board of Directors approved the 2006 Base Salary for Mr. Crane (as previously disclosed in a Form 8-K, filed January 5, 2006) and the Compensation Committee approved the 2006 Base Salary for the other named executive officers. The AIP Payout and the base salary for each named executive officer is set forth in the 2005 AIP Payout and 2006 Base Salary Table attached as Exhibit 10.34 to this Form 10-K and incorporated herein by reference.

On March 1, 2006, the Compensation Committee, duly authorized by the Board of Directors, approved 2006 performance targets for Mr. Crane, President and Chief Executive Officer, Mr. Flexon, Executive Vice President and Chief Financial Officer and the other named executive officers. Performance targets include EBITDA and free cash flow financial goals, as well as non-financial goals in the areas of safety, environmental, strategic development, staff development and individual performance objectives. As noted above, the Chief Executive Officer will have a target opportunity of 100 percent of base salary with an additional maximum opportunity of 100 percent of base salary. The Chief Financial Officer will have a target opportunity of 75 percent of base salary with an additional maximum opportunity of 75 percent of base salary. The remaining named executive officers will have a target opportunity ranging from 50 to 75 percent of base salary with an additional maximum opportunity ranging from 25 to 37.5 percent of base salary.

PART III

Item 10 *Directors and Executive Officers of the Registrant*

NRG 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. It may be accessed through NRG s website at http://www.nrgenergy.com/investor/corpgov.htm. NRG 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 this website and such information will remain available on this website for at least a 12-month period. A copy of the NRG 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 our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 11 *Executive Compensation*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

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

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 13 *Certain Relationships and Related Transactions*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 14 *Principal Accountant Fees and Services*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

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PART IV

Item 15 ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements

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

Consolidated Statement of Operations Year ended December 31, 2005 and the Year ended December 31, 2004 (Reorganized NRG)

Consolidated Balance Sheet December 31, 2005 and December 31, 2004 (Reorganized NRG)

Consolidated Statement of Cash Flows Year ended December 31, 2005 and the Year ended December 31, 2004 (Reorganized NRG)

Consolidated Statement of Stockholders Equity/(Deficit) and Comprehensive Income/(Loss) Year ended December 31, 2005 and the Year ended December 31, 2004 (Reorganized NRG)

Notes to Consolidated Financial Statements

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

Consolidated Statements of Operations The period December 6, 2003 to December 31, 2003 (Reorganized NRG) and the period January 1, 2003 to December 5, 2003 (Predecessor Company)

Consolidated Statements of Cash Flows The period December 6, 2003 to December 31, 2003 (Reorganized NRG) and the period January 1, 2003 to December 5, 2003 (Predecessor Company)

Consolidated Statements of Stockholders Equity/(Deficit) and Comprehensive Income/(Loss) The period December 6, 2003 to December 31, 2003 (Reorganized NRG) and the period January 1, 2003 to December 5, 2003 (Predecessor Company)

Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedule

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

Report of Independent Registered Public Accounting Firm on Financial Statement Schedule.

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

(c) Financial Statement Schedule

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our 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 our management, including our principal executive officer, principal financial officer and principal accounting officer, we conducted an evaluation of the effectiveness of our 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 our evaluation under the framework in Internal Control Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by KPMG LLP, our independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) . NRG Energy, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) . Also, in our opinion, NRG Energy, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) .

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of NRG Energy, Inc. and subsidiaries as of December 31, 2005, and the related consolidated statements of operations, stockholders equity/(deficit) and comprehensive income/(loss), and cash flows for the year then ended December 31, 2005, and our report dated March 7, 2006 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
March 7, 2006

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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, 2005 and 2004, and the related consolidated statements of operations, stockholders equity/(deficit) and comprehensive income/(loss), and cash flows for each of the years in the two year period ended December 31, 2005. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule Schedule II Valuation and Qualifying Accounts. These consolidated financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

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, 2005, 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 March 7, 2006 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
March 7, 2006

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of NRG Energy, Inc.:

In our opinion, the accompanying consolidated statements of operations, cash flows and of stockholders equity/(deficit) and comprehensive income/(loss) of NRG Energy, Inc. and its subsidiaries (Reorganized NRG) present fairly, in all material respects, the results of their operations and their cash flows for the period from December 6, 2003 to December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Notes 1 and 2 to the consolidated financial statements, the United States Bankruptcy Court for the Southern District of New York confirmed the NRG Energy, Inc. Plan of Reorganization on November 24, 2003. Confirmation of the plan resulted in the discharge of all claims against the Company that arose before May 14, 2003 and substantially alters rights and interests of equity security holders as provided for in the plan. The NRG Energy, Inc. Plan of Reorganization was substantially consummated on December 5, 2003, and NRG Energy, Inc. emerged from bankruptcy. In connection with its emergence from bankruptcy, NRG Energy, Inc. adopted fresh start accounting as of December 5, 2003.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 21, and 33, which are as of December 6, 2004

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of NRG Energy, Inc.:

In our opinion, the accompanying consolidated statement of operations, cash flows and of stockholders equity/(deficit) and comprehensive income/(loss) of NRG Energy, Inc. and its subsidiaries (Predecessor Company) present fairly, in all material respects, the results of their operations and their cash flows for the period from January 1, 2003 to December 5, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1 and 2 to the consolidated financial statements, the Company filed a petition on May 14, 2003 with the United States Bankruptcy Court for the Southern District of New York for reorganization under the provisions of Chapter 11 of the Bankruptcy Code. NRG Energy, Inc. s Plan of Reorganization was substantially consummated on December 5, 2003 and Reorganized NRG emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

March 10, 2004, except as to Notes 6, 21, and 33, which are as of December 6, 2004

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NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003
	(In millions, except per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$ 2,708	$ 2,348	$ 137	$ 1,798
Operating Costs and Expenses				
Cost of majority-owned operations	2,067	1,489	95	1,354
Depreciation and amortization	194	208	12	211
General, administrative and development	197	210	13	170
Other charges (credits)				
Corporate relocation charges	6	16		
Reorganization items		(13)	2	198
Restructuring and impairment charges	6	45		237
Fresh start reporting adjustments				(4,220)
Legal settlement				463
Total operating costs and expenses	2,470	1,955	122	(1,587)
Operating Income	238	393	15	3,385
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	104	160	14	171
Write downs and losses on sales of equity method investments	(31)	(16)		(147)
Other income, net	62	27		19
Refinancing expenses	(56)	(72)		
Interest expense	(197)	(266)	(19)	(308)
Total other expense	(118)	(167)	(5)	(265)
Income From Continuing Operations Before Income Taxes	120	226	10	3,120
Income Tax Expense/(Benefit)	43	65	(1)	38
Income From Continuing Operations	77	161	11	3,082

Income/(Loss) on Discontinued Operations, net of Income Taxes		7		25				(316)
Net Income		84		186		11		2,766
Preference stock dividends		20						
Income Available for Common Stockholders	$	64	$	186	$	11	$	2,766
Weighted Average Number of Common Shares Outstanding Basic		85		100		100		
Income From Continuing Operations per Weighted Average Common Share Basic	$	0.67	$	1.61	$	0.11		
Income From Discontinued Operations per Weighted Average Common Share Basic		0.09		0.25				
Net Income per Weighted Average Common Share Basic	$	0.76	$	1.86	$	0.11		
Weighted Average Number of Common Shares Outstanding Diluted		85		100		100		
Income From Continuing Operations per Weighted Average Common Share Diluted	$	0.66	$	1.60	$	0.11		
Income From Discontinued Operations per Weighted Average Common Share Diluted		0.09		0.25				
Net Income per Weighted Average Common Shares Diluted	$	0.75	$	1.85	$	0.11		

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions, except shares and par value)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 506	$ 1,104
Restricted cash	64	110
Accounts receivable-trade, less allowance for doubtful accounts of $2 and $1	280	270
Accounts receivable-affiliate	4	
Current portion of notes receivable and capital lease	25	85
Property taxes receivable	43	37
Inventory	260	247
Derivative instruments valuation	404	80
Collateral on deposit in support of energy risk management activities	438	33
Deferred income taxes	4	
Prepayments and other current assets	125	136
Current assets held for sale	43	
Current assets discontinued operations	1	17
Total current assets	2,197	2,119
Property, Plant and Equipment, net	3,039	3,158
Other Assets		
Equity investments in affiliates	603	735
Notes receivable, less current portion affiliates, net	103	124
Notes receivable and capital lease, less current portion, net	355	440
Intangible assets, net of accumulated amortization of $79 and $55	257	294
Derivative instruments valuation	22	42
Funded letter of credit	350	350
Deferred income tax	26	34
Other assets	125	111
Non-current assets discontinued operations	354	457
Total other assets	2,195	2,587
Total Assets	$ 7,431	$ 7,864

See notes to consolidated financial statements.

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

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions, except shares and par value)	
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 101	$ 511
Accounts payable trade	268	209
Accounts payable affiliates		5
Derivative instruments valuation	692	17
Other bankruptcy settlement	3	6
Accrued expenses	82	57
Other current liabilities	95	109
Current liabilities discontinued operations	115	173
Total current liabilities	1,356	1,087
Other Liabilities		
Long-term debt and capital leases	2,581	2,973
Deferred income taxes	135	169
Postretirement and other benefit obligations	125	116
Derivative instruments valuation	137	148
Out of market contracts	298	319
Other long-term obligations	81	71
Non-current liabilities discontinued operations	240	288
Total non-current liabilities	3,597	4,084
Total liabilities	4,953	5,171
Minority interest	1	1
3.625% Convertible Perpetual Preferred Stock; $.01 par value; 250,000 shares issued and outstanding (at liquidation value of $250, net of issuance costs)	246	
Commitments and Contingencies		
Stockholders Equity		
4% Convertible Perpetual Preferred Stock; $.01 par value; 420,000 shares issued and outstanding at December 31, 2005 and 2004 (at liquidation value of $420, net of issuance costs)	406	406
Common stock; $.01 par value; 100,048,676 and 100,041,935 shares issued and 80,701,888 and 87,041,935 outstanding at December 31, 2005 and 2004, respectively	1	1
Additional paid-in capital	2,431	2,417
Retained earnings	261	197

Less treasury stock, at cost; 19,346,788 and 13,000,000 shares as of December 31, 2005 and 2004, respectively		(663)		(405)
Accumulated other comprehensive income/(loss)		(205)		76
Total stockholders equity		2,231		2,692
Total Liabilities and Stockholders Equity	$	7,431	$	7,864

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY/(DEFICIT)
AND COMPREHENSIVE INCOME/(LOSS)

	Serial Preferred Stock	Serial Preferred Shares	Common Stock	Common Shares	Additional Paid-In Capital	Retained Earnings/ (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders Equity/ (Deficit)
	(In millions)								
Balances at December 31, 2002 (Predecessor Company)	$		$		$ 2,228	$ (2,829)	$	$ (95)	$ (696)
Net income						2,766			2,766
Foreign currency translation adjustments and other								128	128
Deferred unrealized loss on derivatives, net								(32)	(32)
Comprehensive income for the period from January 1, 2003 through December 5, 2003									2,862
Effects of reorganization					(2,228)	63		(1)	(2,166)
Issuance of common stock			1	100	2,403				2,404
Balances at December 5, 2003 (Predecessor Company)	$		$ 1	100	$ 2,403	$	$	$	$ 2,404
Net income						11			11
Foreign currency translation adjustments and other								23	23
Deferred unrealized loss on derivatives, net								(1)	(1)
Comprehensive income for the									33

period from December 6, 2003 through December 31, 2003									
Balances at December 31, 2003 (Reorganized NRG)	$		$ 1	100	$ 2,403	$ 11	$	$ 22	$ 2,437
Net income						186			186
Foreign currency translation adjustments and other								46	46
Deferred unrealized gain on derivatives, net								8	8
Comprehensive income for 2004									240
Equity based compensation					14				14
Issuance of preferred stock	406	0.4							406
Purchase of treasury stock				(13)			(405)		(405)
Balances at December 31, 2004 (Reorganized NRG)	$ 406	0.4	$ 1	87	$ 2,417	$ 197	$ (405)	$ 76	$ 2,692
Net income						84			84
Foreign currency translation adjustments and other								(72)	(72)
Deferred unrealized loss on derivatives, net								(203)	(203)
Minimum pension liability, net of $3 tax								(6)	(6)
Comprehensive loss for 2005									(197)
Equity based compensation					14				14
Preferred stock dividends						(20)			(20)
Purchase of treasury stock				(6)			(258)		(258)

Balances at December 31, 2005 (Reorganized NRG)	$	406	0.4	$	1	81	$	2,431	$	261	$	(663)	$	(205)	$	2,231

See notes to consolidated financial statements.

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

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003
		(In millions)		
Cash Flows from Operating Activities				
Net income	$ 84	$ 186	$ 11	$ 2,766
Adjustments to reconcile net income to net cash provided by operating activities				
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(8)	(1)	2	(41)
Depreciation and amortization	195	215	13	257
Reserve for note and interest receivable		12		
Amortization of financing costs and debt discount/(premium)	22	28	2	18
Write-off of deferred financing costs due to refinancings	(8)	42		
Write downs and losses on sales of equity method investments	31	16		147
Deferred income taxes and investment tax credits	2	57	(3)	(2)
Unrealized (gains)/losses on derivatives	143	(74)	4	(35)
Minority interest	1	1		2
Amortization of intangible assets	17	52	(13)	
Amortization of unearned equity compensations	12	14		
Restructuring and impairment charges	6	45		408
Fresh start reporting adjustments				(3,895)
Loss on sale and disposal of assets	4	1		
Gain on sale of discontinued operations	(6)	(23)		(186)
Gain on TermoRio settlement	(14)			
Collateral deposit payments in support of energy risk management activities	(405)	(7)	(8)	

Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions				
Accounts receivable, net	(8)	(52)	18	28
Xcel Energy settlement receivable		640		
Inventory	(14)	(56)	11	14
Prepayments and other current assets	(35)	126	(71)	(37)
Accounts payable	57	50	(40)	649
Accrued expenses	(8)	(21)	(67)	217
Creditor pool obligation payments		(540)		
Other current liabilities	(8)	(106)	(441)	(23)
Other assets and liabilities	8	40	(7)	(49)
Net Cash Provided (Used) by Operating Activities	68	645	(589)	238
Cash Flows from Investing Activities				
Proceeds from sale of discontinued operations	36	253		19
Proceeds from sale of investments	70	51		107
Proceeds from sale of turbines and other property, plant and equipment	9	4		71
Decrease/(increase) in restricted cash and trust funds	45	(27)	375	(266)
Decrease/(increase) in notes receivable	107	25	1	(2)
Deferred acquisition costs	(5)			
Capital expenditures	(106)	(119)	(11)	(114)
Return of capital/(Investments) in projects	2	(3)	(2)	(1)
Net Cash Provided (Used) by Investing Activities	158	184	363	(186)
Cash Flows from Financing Activities				
Payment of dividends to preferred shareholders	(20)			
Repayment of minority interest obligations	(4)			
Accelerated share repurchase payment, net	(250)			
Purchase of treasury stock		(405)		
Issuance of 4% Preferred Stock, net		406		
Issuance of 3.625% Preferred Stock, net	246			
Proceeds from issuance of long-term debt, net	249	1,333	2,450	40
Deferred debt issuance costs	(46)	(26)	(75)	(19)
Funded letter of credit		(100)	(250)	

Principal payments on short and long-term debt	(1,005)	(1,492)	(1,732)	(51)
Net Cash Provided (Used) by Financing Activities	(830)	(284)	393	(30)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(2)	3	(14)	(22)
Change in Cash from Discontinued Operations	8	6	1	35
Net Increase/(Decrease) in Cash and Cash Equivalents	(598)	554	154	35
Cash and Cash Equivalents at Beginning of Period	1,104	550	396	361
Cash and Cash Equivalents at End of Period	$ 506	$ 1,104	$ 550	$ 396

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization

General

We are a leading wholesale power generation company with a significant presence in many of the major competitive power markets in the United States. We are primarily engaged in the ownership and operation of power generation facilities, purchasing fuel and transportation services to support our power plant operations, and the marketing and trading of energy, capacity and related products in the competitive markets in which we operate.

Our facilities consist primarily of baseload, intermediate and peaking power generation facilities, and also include thermal energy production and energy resource recovery plants. The sale of capacity and power from baseload generation facilities accounts for the majority of our revenues and provides a stable source of cash flow. In addition, our diverse generation portfolio provides us with opportunities to capture additional revenues by selling power into our core regions 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 February 2, 2006, NRG completed the acquisition of Texas Genco, or the Acquisition. The purchase price of approximately $6.1 billion consisted of approximately $4.4 billion in cash and the issuance of approximately 35.4 million shares of NRG s common stock valued at $1.7 billion. This amount is subject to adjustment due to acquisition costs. The value of our common stock issued to the former direct and indirect owners of Texas Genco, or the Sellers, was based on our average stock price immediately before and after the closing date of February 2, 2006. The Acquisition includes the assumption of approximately $2.7 billion of Texas Genco debt. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

We were formed in 1992 as the non-utility subsidiary of Northern States Power Company, or NSP, which was itself merged into New Century Energies, Inc. to form Xcel Energy, Inc., or Xcel Energy, in 2000. In 2002, a number of factors including the overall downturn in the power generation industry, triggered a series of credit rating downgrades which, in turn, precipitated a severe liquidity crisis at the Company. From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code.

As part of our reorganization, Xcel Energy relinquished its ownership interest in us, and we became an independent public company. We no longer have any material affiliation or relationship with Xcel Energy. As part of our restructuring, on December 23, 2003, we used the proceeds of a new $1.25 billion offering of 8% second priority senior secured notes due 2013, and borrowings under a new $1.45 billion secured credit facility, to retire approximately $1.7 billion of project-level debt.

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

Note 2 Summary of Significant Accounting Policies

Nature of Operations

We are a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type, and dispatch levels, which help mitigate risk. We seek to maximize operating income through the efficient

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NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets.

Principles of Consolidation and Basis of Presentation

Between May 14, 2003 and December 5, 2003, we operated as a debtor-in-possession under the supervision of the bankruptcy court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of SOP 90-7.

For financial reporting purposes, close of business on December 5, 2003, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

Predecessor Company	The Company, pre-emergence from bankruptcy The Company s operations prior to December 6, 2003
Reorganized NRG	The Company, post-emergence from bankruptcy The Company s operations, December 6, 2003-December 31, 2005

In January 2003, the FASB issued FIN 46 which requires an enterprise s consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. In December 2003, the FASB published a revision to Interpretation 46, or FIN 46R, to clarify some of the provisions of FIN 46 and to exempt certain entities from its requirements. As required by SOP 90-7, we adopted FIN 46R as of the adoption of Fresh Start and consequently we have consolidated operations of hydropower facilities on the East Coast, Northbrook New York and Northbrook Energy. These operations have been sold during 2005 and classified as discontinued operations. Also see Note 6 for further discussion.

The consolidated financial statements include our accounts and operations and those of our subsidiaries in which we have a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America. As discussed in Note 13, we have investments in partnerships, joint ventures and projects.

Fresh Start Reporting

In accordance with SOP 90-7, certain companies qualify for fresh start reporting in connection with their emergence from bankruptcy. Fresh start reporting is appropriate on the emergence from chapter 11 if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post-petition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. We met these requirements and adopted Fresh Start reporting resulting in the creation of a new reporting entity designated as Reorganized NRG.

The bankruptcy court issued a confirmation order approving our plan of reorganization on November 24, 2003. Under the requirements of SOP 90-7, the Fresh Start date is determined to be the confirmation date unless significant uncertainties exist regarding the effectiveness of the bankruptcy order. Our plan of reorganization required completion of the Xcel Energy settlement agreement prior to emergence from bankruptcy. The Xcel Energy settlement agreement was entered into on December 5, 2003. We believe this settlement agreement was a significant contingency and thus delayed the Fresh Start date until the Xcel Energy settlement agreement was finalized on December 5, 2003.

Under the requirements of Fresh Start, we adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was a negative reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS 109. The

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations), which is reflected in the Predecessor Company s results for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management s forecast of expected cash flows from our core assets. Management s forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a forward looking approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisor prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the bankruptcy Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and Court s approval of the Plan of Reorganization.

A separate plan of reorganization was filed for our Northeast Generating and South Central Generating entities that was confirmed by the bankruptcy court on November 25, 2003, and became effective on December 23, 2003, when the final conditions of the plan were completed. In connection with Fresh Start on December 5, 2003, we have accounted for these entities as if they had emerged from bankruptcy at the same time that we emerged, as we believe that we continued to maintain control over the Northeast Generating and South Central Generating facilities throughout the bankruptcy process.

Due to the adoption of Fresh Start upon our emergence from bankruptcy, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company s statement of operations and statement of cash flows and are therefore not comparable to these statements prior to the application of Fresh Start.

Cash and Cash Equivalents

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

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within our 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.

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventory

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

Property, Plant and Equipment

Property, plant and equipment are stated at cost however impairment adjustments are recorded whenever events or changes in circumstances indicate carrying values may not be recoverable. On December 5, 2003, we recorded adjustments to the property, plant and equipment to reflect such items at fair value in accordance with Fresh Start reporting. A new cost basis was established with these adjustments. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation will be computed using the straight-line method over the following estimated useful lives:

Facilities and equipment	1-42 years
Office furnishings and equipment	2-10 years

The assets and related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with SFAS 144. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset s carrying amount and fair value and included in operating costs and expenses in the statement of operations. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with APB 18 which requires that a loss in value of an investment that is other than a temporary decline should be recognized. We identify and measure losses in value of equity investments based upon a comparison of fair value to carrying value.

Discontinued Operations

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

Capitalized Interest

Interest incurred on funds borrowed to finance projects expected to require more than three months to complete is capitalized. Capitalization of interest is discontinued when the asset under construction is ready for its intended use or when a project is terminated or construction ceased. Capitalized interest was approximately $0.2 million, $3 million, $1 million, and $5 million for the years ended December 31, 2005 and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2004, and the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, respectively.

Capitalized Project Costs

Development costs and capitalized project costs include third party professional services, permits, and other costs that are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and our Board of Directors has approved the project. Additional costs incurred after this point are capitalized. When a project begins operations, previously capitalized project costs are reclassified to equity investments in affiliates or property, plant and equipment and amortized on a straight-line basis over the lesser of the life of the project s related assets or revenue contract period. 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 terms of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by us. Intangible assets are amortized over their economic useful life and reviewed for impairment on a periodic basis.

Income Taxes

The Reorganized NRG s income tax provision for the years ended December 31, 2005 and December 31, 2004, and for the period December 6, 2003 through December 31, 2003 has been recorded on the basis that we and our U.S. subsidiaries reconsolidated for federal income tax purposes as of December 6, 2003. The Reorganized NRG is no longer owned by Xcel Energy and thus, no longer included in the Xcel Energy affiliated group. The change in ownership allows us to file a consolidated federal income tax return with our U.S. subsidiaries starting on December 6, 2003.

The Predecessor Company s income tax provision has been recorded on the basis that Xcel Energy has not included us in its consolidated federal income tax return following Xcel Energy s acquisition of our public shares on June 3, 2002. Since we and our U.S. subsidiaries will not be included in the Xcel Energy s consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes filed a separate federal income tax return for the period ended December 5, 2003.

Deferred income taxes are recognized for the tax consequences in future years of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at each year-end based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Income tax expense is the tax payable for the period and the change during the period in deferred tax assets and liabilities. A valuation allowance is recorded to reduce deferred tax assets to the amount more likely than not to be realized.

Revenue Recognition

We are primarily an electric generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which our ownership interest is 50% or less which are accounted for under the equity method of accounting. In connection with our electric generation business, we also produce thermal energy for sale to customers, principally through steam and chilled water facilities. We also collect

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

methane gas from landfill sites, which are used for the generation of electricity. In addition, we sell small amounts of natural gas and oil to third parties.

Energy. Both physical and financial transactions are entered into to optimize the financial performance of our generating facilities. Electric energy revenue is recognized upon transmission to the customer. We record gross revenues in regions where bilateral markets exist and physical delivery of electricity is common from our plants under the accrual method. In certain markets, which are operated and/or controlled by an ISO and in which we have entered into a netting agreement with the ISO, which results in our receiving a netted invoice, we have recorded purchased energy as an offset against revenues received upon the sale of such energy. Revenues derived from the buying and selling of electricity from an ISO and not sourced from our facilities are reported net.

Capacity. Capacity and ancillary revenue is recognized when contractually earned, and 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. We provide contract operations and maintenance services to some of our non-consolidated affiliates. Revenue is recognized as contract services are performed.

Revenue from Sales of Emission Allowances. During 2005, we began selling our excess SO_2 emission allowances. We record the sale of these allowances in Operating Revenues. The cost basis of these allowances, established upon the adoption of Fresh Start, is recorded in Operating Costs and Expenses. Beginning in 2006, we will actively manage our SO_2 emission allowances as well as fuels, and we will account for such asset optimization activity related to emission allowances and other fuel commodities under EITF 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* As such, revenues and costs for the asset and optimization activities would be reflected on a net basis in the consolidated statement of operations.

Contract Amortization. At Fresh Start we recognized liabilities for power sales agreements related to the sale of electric capacity and energy in future periods where the fair value was determined to be significantly out of market as compared to market expectations. The liability is being amortized as an increase to revenue over the term of each underlying contract based on actual generation. The carrying amount of the unfavorable out-of-market power sales agreements at December 31, 2005 and 2004 was $298 million and $319 million, respectively. The estimated annual amortization of the out-of-market power sales agreements for each of the five succeeding years is expected to approximate $37 million in 2006, $28 million in 2007, $24 million in 2008, $24 million in 2009 and $20 million for 2010.

Disputed Revenues. Disputed revenues are not recorded in the financial statements until disputes are effectively resolved and collection is reasonably assured.

Derivative Financial Instruments

In January 2001, we adopted SFAS 133, as amended by SFAS 137, SFAS 138 and SFAS 149. SFAS 133, as amended, requires us to record all derivatives on the balance sheet at fair value. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced, and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. 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 for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings. We primarily account for derivatives under SFAS 133, as amended, for as long-term power sales contracts, long-term gas purchase contracts and other energy related commodities and financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and to protect investments in fuel inventories. SFAS 133, as amended, also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS 133, as amended, results in increased volatility in earnings due to the recognition of unrealized gains and losses. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate, third party experts in determining the fair value of these derivatives.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of our 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 weighted-average rates of exchange for the period. The resulting currency translation adjustments are accumulated and reported as a separate component of stockholders equity and are not included in the determination of the results of operations. Foreign currency transaction gains or losses are reported in results of operations. We recognized foreign currency transaction gains (losses) of $(1) million, $2 million, $0.4 million, and $(20) million for the years ended December 31, 2005, December 31, 2004, and the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, respectively.

Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of cash, trust funds, accounts receivable, notes receivable and investments in debt securities. Cash accounts and trust funds are generally held in federally insured banks. Accounts receivable, notes receivable and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables are generally not collateralized; however, we believe the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, trust funds, receivables, accounts payables, and accrued liabilities approximate fair value because of the short 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. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Pensions

The determination of our 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. Our 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 us.

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Stock Based Compensation

During the fourth quarter of 2003, in accordance with SFAS Statement No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* we adopted SFAS 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. As a result, we applied the fair value recognition provisions of SFAS 123 as of January 1, 2003. We recognize compensation expense on a graded vesting basis for non-qualified stock option grants issued under the Long-Term Incentive Plan. The Black-Scholes option-pricing model is used for all non-qualified stock options. We recognize compensation expense on a straight-line basis over the applicable vesting period for restricted stock units (RSUs) and performance units (PUs). We use our common stock price on the date of grant as the fair value of the RSUs, while the fair value of the PU s is estimated on the date of grant using the Monte Carlo valuation model. In January 2006, we will adopt SFAS 123(R) under a modified version of prospective application as discussed below in *Recent Accounting Pronouncements.*

Use of Estimates

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

In recording transactions and balances resulting from business operations, we use estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of long-term energy commodities contracts and environmental liabilities, and legal costs incurred in connection with recorded loss contingencies, among others. In addition, estimates are used to test long-lived assets for impairment and to determine fair value of impaired assets. As better information becomes available (or actual amounts are determinable), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on our net income or total stockholders equity as previously reported.

Recent Accounting Developments

During the period, the FASB issued FIN 47 to clarify the term conditional asset retirement obligation as used in SFAS 143 governing the application of Asset Retirement Obligations. SFAS 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional but there may remain some uncertainty as to the timing and/or method of settlement. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction, or development and/or through the normal operation of the asset. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 clarifies when the company would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effective for fiscal years ending after December 15, 2005. This guidance does not materially affect our consolidated financial position, results of operations or statement of cash flows.

Also during the period, the SEC issued Staff Accounting Bulletin 107, or SAB 107, which addresses the application of SFAS 123(R). SAB 107 was issued to assist registrants by simplifying some of the implementation challenges of SFAS 123(R) while enhancing the information that investors receive. SAB 107 creates a framework that is premised on two overarching themes considerable judgment will be required by preparers to successfully implement SFAS 123(R), specifically when valuing employee stock options, and that reasonable individuals, acting in good faith, may conclude differently on the fair value of employee stock options. Accordingly, situations in which there is only one acceptable fair value estimate are expected to be rare. In addition, the SEC extended the adoption date to registrants for the implementation of SFAS 123(R) and SAB 107 so that they may implement this guidance for their fiscal year which begins after September 15, 2005. We will adopt SFAS 123(R) and SAB 107 on January 1, 2006 under a modified version of prospective application, or the modified prospective application. Under modified prospective application, we will apply the provisions of SFAS 123(R) to new awards and to awards modified, repurchased, or cancelled after the required effective date. In addition to applying a forfeiture rate to new awards, we are required to apply a forfeiture rate to existing awards and, if material, eliminate from balance sheet amounts and recognize in income as the cumulative effect of a change in accounting principle as of the required effective date. This guidance will not materially affect our consolidated financial position, results of operations or statement of cash flows.

Subsequent to release of SFAS 123R, the FASB issued Staff Position No. FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, or FSP FAS 123R-3, on November 10, 2005. FSP FAS 123R-3 provides a one-time election related to the accounting for the tax benefits from share-based compensation cost since the adoption of FAS 123, and allows for purposes of calculating current tax expense, the aggregation of tax benefits recognized for share-based compensation in excess of financial statement tax benefits since adoption of FAS 123 in lieu of the award-by-award basis prescribed by SFAS 123R. We are currently evaluating the impact of this election, but do not expect this guidance to materially affect our consolidated financial position, results of operations or statement of cash flows.

On March 17, 2005, the Emerging Issues Task Force, or EITF, issued EITF No. 04-6 *Accounting for Stripping Costs Incurred during Production in the Mining Industry*, or EITF 04-6. EITF 04-6 provides that costs incurred to remove overburden and waste material to access coal seams, or stripping costs, during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005. Our MIBRAG equity investment is a 50% interest in a mining company, which will be negatively affected by this pronouncement. Currently, MIBRAG has an asset totaling approximately 157 million, approximately $185 million, representing the stripping costs incurred during production as of December 31, 2005. The adoption of EITF 04-6 will not have a material impact on our consolidated results of operations, but will have a material impact on our consolidated financial position. Following adoption on January 1, 2006, our investment in MIBRAG will be reduced by 50% of the above mentioned asset, approximately $93 million, with an offsetting charge to retained earnings.

Also during the period, the FASB issued SFAS No. 154 *Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3*, or SFAS 154. This Statement replaces APB Opinion No. 20, *Accounting Changes*, or APB 20, and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements*, and changes the requirements for the accounting for and reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific

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transition provisions, those provisions should be followed. APB 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application to prior periods financial statements of changes in accounting principle for direct effects of the change, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change, and redefines restatement as the revising of previously issued financial statements to reflect the correction of an error. This Statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

On July 12, 2005, the FASB issued Staff Position APB 18-1, *Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence*, or FSP APB 18-1. This guidance clarifies the application of paragraph 121 of SFAS No. 130, *Reporting Comprehensive Income*, or SFAS 130, and clarifies that the company s proportionate share of an investee s equity adjustments for OCI should be offset against the carrying value of the investment at the time significant influence is lost. To the extent that the offset results in a carrying value of the investment that is less than zero, an investor should (a) reduce the carrying value of the investment to zero and (b) record the remaining balance in income. The guidance in FSP APB 18-1 is effective as of the first reporting period after July 12, 2005. Currently, this guidance does not materially affect our consolidated financial position, results of operations or statement of cash flows.

On June 29, 2005, the EITF issued EITF Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, or EITF 04-5. EITF 04-5 provides a framework for addressing when a general partner controls a limited partnership when the limited partners have certain rights. EITF 04-5 s scope excludes a number of investment types, including limited partnerships entities that are not variable interest entities under FIN 46R, and investments accounted for under the pro rata method of consolidation. The guidance in EITF 04-5 is effective immediately to general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified. For general partners in all other limited partnerships, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. Currently, this guidance will not materially affect our consolidated financial position, results of operations or statement of cash flows.

On June 16, 2005, the EITF issued EITF Issue No. 05-5, *Accounting for Early Retirement or Postemployment Programs with Specific Features (Such As Terms Specified in Altersteilzeit Early Retirement Arrangements)*, or EITF 05-5. EITF 05-5 provides guidance on the accounting for early retirement or postemployment programs with specific features, and specifically the terms of Altersteilzeit early retirement arrangements. The Altersteilzeit (ATZ) arrangement is a voluntary early retirement program in Germany designed to create an incentive for employees, within a certain age group, to transition from employment into retirement before their legal retirement age. If certain criteria are met by the employer, the German government provides to the employer a subsidy for bonuses paid to the employee and the additional contributions paid by the employer into the German government pension scheme under an ATZ arrangement for a maximum of six years. The Task Force reached a consensus that the employer should recognize the government subsidy when it meets the necessary criteria and is entitled to the subsidy. The Task Force also reached a consensus that payments made by the employer relative to the bonus feature and the additional contributions into the German government pension scheme (collectively, the additional compensation) should be accounted for as a post-employment benefit under SFAS 112, *Employers Accounting for Post-employment Benefits*, which prescribes than an entity should recognize the additional compensation over the period from the point at which the employee signs the ATZ contract until the end of the active service period. The guidance of EITF 05-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We are currently evaluating the impact of this election, but do not expect this guidance to materially affect our consolidated financial position, results of operations or statement of cash flows.

Note 3 Emergence from Bankruptcy and Fresh Start Reporting

In accordance with the requirements of SOP 90-7, we determined the reorganization value of NRG and subsidiaries emerging from bankruptcy to be approximately $9.1 billion. Reorganization value generally approximates fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Several methods are used to determine the reorganization value; however, generally it is determined by discounting future cash flows for the reconstituted business that will emerge from chapter 11 bankruptcy. Our approach was consistent in that our independent financial advisor s estimated reorganization enterprise value of our ongoing projects used a discounted cash flow approach.

We allocated the reorganization value of $9.1 billion to our assets in conformity with the procedures specified by SFAS 141. We used a third party to complete an independent appraisal of our tangible assets, equity investments and intangible assets and contracts. In completing the fair value allocation our assets were calculated to be greater than the reorganization value. As a result, we reallocated the negative reorganization value to our tangible and intangible assets in accordance with SFAS 141. In preparing our balance sheet we also recorded each liability existing at the plan confirmation date, other than deferred taxes, at the present value of amounts to be paid determined at appropriate current interest rates. Deferred taxes were reported in conformity with generally accepted accounting principles under SFAS 109. Our equity was recorded at approximately $2.4 billion representing a price per share of $24.04 for the issuance of 100 million shares of common stock upon emergence from bankruptcy. We pushed down the effects of fresh start reporting to all of our subsidiaries.

In constructing our Fresh Start balance sheet using our reorganization value upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Accordingly, our reorganization value of $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. This value is consistent with the voting creditors and Court s approval of the Plan of Reorganization.

The determination of the enterprise value and the allocations to the underlying assets and liabilities were based on a number of estimates and assumptions, which are inherently subject to significant uncertainties and contingencies.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in the Predecessor Company s statement of operations for 2003, which includes the gain on the restructuring of debt and equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company s financial statements and are not comparable in certain respects to the financial statements prior to

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the application of Fresh Start. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

	Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments	Consolidation	NRG December 6, 2003
			(In millions)		
Current Assets	$ 1,718	$ 614	$ 4	$ 6	$ 2,342
Non-current Assets	8,172	(155)	(1,233)	41	6,825
Total Assets	$ 9,890	$ 459	$ (1,229)	$ 47	$ 9,167
Current Liabilities	2,190	999	1,187	1	4,377
Non-current Liabilities	9,458	(6,270)	(848)	46	2,386
Total Liabilities	11,648	(5,271)	339	47	6,763
Stockholders Equity	(1,758)	2,404	1,758		2,404
Total Liabilities and Stockholders Equity	$ 9,890	$ (2,867)	$ 2,097	$ 47	$ 9,167

APB 18 requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee was a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power s California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the amount of approximately $10 million per month during 2004 until the contract expired in December 2004.

Note 4 Debtors Statements

As stated above, we and certain of our subsidiaries filed voluntary petitions for reorganization under chapter 11 of the Bankruptcy Code during 2003. On December 5, 2003, we and five of our subsidiaries emerged from bankruptcy. As of the respective bankruptcy filing dates, the debtors financial records were closed for the pre-petition period. As required by SOP 90-7, below are the condensed combined financial statements of our remaining debtors since the date of the bankruptcy filings, or the Debtors Statements.

The Debtors Statements consist of the following wholly-owned consolidated entities which remained in bankruptcy as of December 6, 2003: Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Berrians I Gas Turbine Power, LLC, Big Cajun II Unit 4 LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Louisiana Generating LLC, LSP-Nelson Energy LLC, Middletown Power LLC, Montville Power LLC, Northeast Generation Holding LLC, Norwalk Power LLC, NRG Central US LLC, NRG Eastern LLC, NRG McClain LLC, NRG Nelson Energy LLC, NRG New Roads Holdings LLC, NRG Northeast Generating LLC, NRG South Central Generating LLC, Oswego Harbor Power LLC, Somerset Power LLC, and South Central Generation Holding LLC. As of December 31, 2005, there were no entities remaining in bankruptcy.

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Debtors Condensed Combined Statement of Operations

	For the Period May 15, 2003 December 5, 2003	
	(In millions)	
Operating revenue	$	731
Operating costs and expenses		(620)
Fresh start reporting adjustments asset write-downs, net		(1,244)
Reorganization items		(27)
Restructuring and impairment charges		(23)
Operating loss		(1,183)
Other expense		(161)
Net loss	$	(1,344)

Debtors Condensed Combined Statement of Cash Flows

	For the Period May 15, 2003 December 5, 2003	
	(In millions)	
Net cash provided by operating activities	$	66
Net cash used by investing activities		(73)
Net cash used by financing activities		
Net increase in cash and cash equivalents		(7)
Cash and cash equivalents at beginning of period		23
Cash and cash equivalents at end of period	$	16

Note 5 Financial Instruments

The estimated fair values of our recorded financial instruments are as follows:

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	Carrying Amount	Carrying Amount

		Fair Value		Fair Value
	(In millions)			
Cash and cash equivalents	$ 506	$ 506	$ 1,104	$ 1,104
Restricted cash	64	64	110	110
Trust fund investments	20	20	20	20
Unfunded letters of credit and surety bonds		13		21
Notes receivable, including current portion	483	494	649	662
Long-term debt, including current portion	2,682	2,809	3,484	3,624

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For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments. Trust funds investments are comprised of various U.S. debt securities carried at fair market value. Unfunded letters of credit and surety bonds are off balance sheet and are short term by nature. Because of their short-term characteristics, their balance approximates fair value.

The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Note 6 Discontinued Operations

We have classified certain business operations, and gains/(losses) recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued. We have also classified certain assets as held for sale as management has committed to selling certain long lived assets within the next year. This classification does not affect prior period operating results.

SFAS 144 requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions our management considered cash flow analyses, bids and offers related to those assets and businesses. This amount is included in income/(loss) on discontinued operations, net of income taxes in the accompanying Statement of Operations. In accordance with the provisions of SFAS 144, assets held for sale will not be depreciated commencing with their classification as such.

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The assets and liabilities of the discontinued operations are reported in the December 31, 2005 and 2004 balance sheets as discontinued operations. The major classes of assets and liabilities are presented by geographic area in the following table.

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	Wholesale Power Generation	Wholesale Power Generation
	Other North America	Other North America
	Consists of Audrain	Consists of McClain, Northbrook New York, Northbrook Energy and Audrain
	(In millions)	
Cash and cash equivalents	$	$ 8
Restricted cash		5
Receivables, net		2
Inventory	1	1
Other current assets		1
Current assets discontinued operations	1	17
Property, plant and equipment, net	114	217
Notes Receivable	240	240
Non-current assets discontinued operations	354	457
Current portion of long-term debt		1
Accounts payable trade		1
Other current liabilities	115	171
Current liabilities discontinued operations	115	173
Long-term debt	240	281
Minority interest		6
Other non-current liabilities		1

Non-current liabilities discontinued operations	240	288

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NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes our discontinued operations for all periods presented in our consolidated financial statements:

Project	Segment	Initial Discontinued Operations Treatment Date	Disposal Date
Killingholme	Other International	Fourth Quarter 2002	First Quarter 2003
NLGI	Alternative Energy	Second Quarter 2003	Second Quarter 2003
TERI	Non-Generation	Third Quarter 2003	Third Quarter 2003
McClain	Other North America	Third Quarter 2003	Third Quarter 2004
NEO Corporation (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC)	Alternative Energy	Fourth Quarter 2003	Fourth Quarter 2003
Cahua and Energia Pacasmayo	Other International	Fourth Quarter 2003	Fourth Quarter 2003
PERC	Other North America	First Quarter 2004	Second Quarter 2004
Cobee	Other International	First Quarter 2004	Second Quarter 2004
Hsin Yu	Other International	Second Quarter 2004	Second Quarter 2004
LSP Energy (Batesville)	Other North America	Second Quarter 2004	Third Quarter 2004
NEO Corporation (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC)	Alternative Energy	Third Quarter 2004	Third Quarter 2004
Northbrook New York and Northbrook Energy	Other North America	Third Quarter 2005	Third Quarter 2005
Audrain	Other North America	Fourth Quarter 2005	Second Quarter 2006

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NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized results of operations were as follows:

Description	Reorganized NRG Year Ended December 31, 2005	Reorganized NRG Year Ended December 31, 2004	Reorganized NRG For the Period December 6 - December 31, 2003	Predecessor Company For the Period January 1 - December 5, 2003
	(In millions)			
Operating revenues	$ 15	$ 122	$ 20	$ 263
Operating costs and other expenses	13	119	20	753
Pre-tax income/(loss) from operations of discontinued components	2	3		(490)
Income tax expense/(benefit)	1			(22)
Income/(loss) from operations of discontinued components	1	3		(468)
Disposal of discontinued components pre-tax gain (net)	13	30		152
Income tax expense/(benefit)	7	8		
Disposal of discontinued components gain (net)	6	22		152
Income/(loss) on discontinued operations, net of income taxes	$ 7	$ 25	$	$ (316)

Operating costs and other expenses for 2005 shown in the table above include the impairment of Audrain s fixed assets and consequent reduction in the estimated liability by approximately $57 million, offsetting each other with no impact to Audrain s results. Due to the sale of our Audrain facility to AmerenUE for $115 million, the fixed asset was impaired to its fair value. Based on the agreement with CSFB, CSFB will receive only $115 million, reducing the corresponding estimated liability.

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NRG ENERGY, INC. AND SUBSIDIARIES
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Operating costs and other expenses for 2004 include asset impairment charges of approximately $0.2 million. Operating costs and other expenses for 2003 include asset impairment charges of approximately $226 million, comprised of approximately $101 million for McClain, $24 million for NLGI and $101 for Audrain. The pre-tax gain or loss on disposals of discontinued components consist of the following:

Project	Segment	Reorganized NRG			Predecessor Company
		Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
		(In millions)			
Northbrook Energy, Northbrook New York	Other North America	$ 12	$	$	$
McClain	Other North America		(3)		
PERC	Other North America		3		
Cobee	Other International		3		
LSP Energy Batesville	Other North America		11		
Hsin Yu	Other International		10		
NEO Nashville, Hackensack, Prima Deshecha, Tajiguas	Alternative Energy		6		
Killingholme	Other International				191
TERI	Non-Generation				1
Cahua and Energia Pacasmayo	Other International				(37)
Others					(3)
Total gain on disposal of discontinued components pre-tax		$ 12	$ 30	$	$ 152

Audrain Generating LLC On December 8, 2005 NRG entered into an Asset Purchase and Sale Agreement to sell all the assets of NRG Audrain Generating LLC, or Audrain, to AmerenUE, a subsidiary of Ameren Corporation. The purchase price is $115 million, subject to customary purchase price adjustments. The transaction is expected to close during the second quarter of 2006. The sale is subject to customary approvals, including Federal Energy Regulatory

Commission, Missouri Public Utilities Commission, Illinois Commerce Commission, and Hart-Scott-Rodino review. We expect to record a gain of approximately $15 million at closing.

Northbrook New York LLC and Northbrook Energy LLC On August 11, 2005, we completed the sale of Northbrook New York LLC and Northbrook Energy LLC. In exchange for the sale, we received net cash proceeds of $36 million and paid off Northbrook New York LLC s third party debt of $17 million. We recognized a net pre-tax gain of $12 million in the third quarter of 2005.

McClain We reviewed the recoverability of our McClain assets pursuant to SFAS No. 144 and recorded a charge of $101 million in the second quarter of 2003. On August 14, 2003, NRG s Board of Directors approved a plan to sell its 77% interest in McClain Generating Station, a 520-MW combined-cycle, natural gas-fired facility located in New Castle, Oklahoma. On July 9, 2004, NRG McClain completed the sale of its 77% interest in the McClain Generating Station to Oklahoma Gas & Electric Company. The Oklahoma Municipal Power Authority will continue to own the remaining 23% interest in the facility. The proceeds of $160 million from the sale were used to repay outstanding project debt under the secured term

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

loan and working capital facility. A loss of $3 million was recognized as of June 30, 2004 based upon the final terms of the sale.

Penobscot Energy Recovery Company (PERC) During the first quarter of 2004, we received board authorization to proceed with the sale of our interest in PERC to SET PERC Investment LLC which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of $18 million, resulting in a gain of approximately $3 million.

Cobee During the first quarter of 2004, we entered into an agreement for the sale of our interest in our Cobee project to Globeleq Holdings Limited, which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of approximately $50 million, resulting in a gain of $3 million.

LSP Energy Batesville On August 24, 2004, we completed the sale of our 100 percent interest in an 837-megawatt generating plant in Batesville, Mississippi to CEP Batesville Acquisition, LLC. CEP Batesville Acquisition, LLC assumed approximately $300 million of outstanding project debt. The transaction resulted in the elimination of $289 million in consolidated debt from NRG Energy s balance sheet. In exchange for the sale, we received cash proceeds of $28 million. We recorded a gain of $11 million in 2004.

Hsin Yu During the second quarter of 2004, we entered into an agreement for the sale of our interest in our Hsin Yu project to a minority interest shareholder, Asia Pacific Energy Development Company Ltd., which reached financial closing in May 2004. Completion of the transaction resulted in a gain of approximately $10 million, resulting from our negative equity in the project. In addition, although we have no continuing involvement in the project, we retained the prospect of receiving an additional $1 million in additional proceeds upon final closing of Phase II of the project.

NEO Corporation In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville). During the third quarter of 2004, we completed the sale of four wholly-owned entities NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC, as well as the sale of several NEO investments Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. Upon completion of the transaction, we received cash proceeds of $6 million, resulting in a $6 million gain associated with the four wholly-owned entities sold and received cash proceeds of $6 million resulting in a loss of approximately $4 million attributable to the equity investments sold. The sale of these equity investments do not qualify for reporting purposes as discontinued operations.

Killingholme In January 2003, we completed the sale of our interest in the Killingholme project to our lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360 million at December 31, 2002. The sale of our interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $191 million. The gain results from the write-down of the project s assets in the third quarter of 2002 below the carrying value of the related debt.

NLGI During the quarter ended March 31, 2003, we recorded impairment charges of $24 million related to subsidiaries of NLGI and a charge of $14 million to write off our 50% investment in Minnesota Methane, LLC. Through April 30, 2003, NRG Energy and NLGI failed to make certain payments causing a default under NLGI s term loan agreements. In May 2003, the project lenders to the wholly-owned subsidiaries of NLGI and Minnesota Methane LLC foreclosed on our membership interest in the NLGI subsidiaries and our equity interest in Minnesota Methane LLC. There was no material gain or loss recognized as a result of the foreclosure.

TERI In September 2003, we completed the sale of TERI, a biomass waste-fuel power plant located in Florida and a wood processing facility located in Georgia, to DG Telogia Power, LLC. The sale resulted in

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net proceeds of approximately $1 million. We entered into an agreement to sell the wood processing facility on behalf of DG Telogia Power, LLC. This sale was completed during fourth quarter 2003 and we received cash consideration of approximately $1 million, resulting in a net gain on sale of approximately $1 million.

Cahua and Energia Pacasmayo In November 2003, we completed the sale of Cahua and Energia Pacasmayo resulting in net cash proceeds of approximately $16 million and a loss of $37 million. In addition, we received an additional consideration adjustment of approximately $1 million during 2004.

Note 7 Write Downs and (Gains)/ Losses on Sales of Equity Method Investments

Investments accounted for by the equity method are reviewed for impairment in accordance with APB 18 which requires that a loss in value of an investment that is other than a temporary decline should be recognized. Gains or losses are recognized on completion of the sale. Write downs and (gains)/losses on sales of equity method investments recorded in other income/expense in the consolidated statement of operations includes the following:

		Reorganized NRG			Predecessor Company
	Segment	**Year Ended December 31, 2005**	**Year Ended December 31, 2004**	**For the Period December 6 - December 31, 2003**	**For the Period January 1 - December 5, 2003**
		(In millions)			
Saguaro	Western	$ 27	$	$	$
Rocky Road	Other North America	20			
Kendall	Other North America	(4)			
Enfield	Other International	(12)			
Commonwealth Atlantic Limited Partnership	Other North America		5		
James River Power LLC	Other North America		7		
NEO Corporation	Alternative Energy		4		
Calpine Cogeneration	Other North America		(1)		
NLGI Minnesota Methane	Alternative Energy				12
NLGI MM Biogas	Alternative Energy				3
ECKG	Other International				(3)
Loy Yang	Australia		1		146
Mustang					(12)

	Other North America				
Other					1
Total write downs and losses on sales of equity method investments		$ 31	$ 16	$	$ 147

Saguaro During the fourth quarter of 2005, due to the expiration of its long-term gas supply contract and higher market prices paid for natural gas, NRG determined that a decline in the value of its 50% investment in Saguaro was considered to be permanent and recorded a write down of its investment of approximately $27 million.

Rocky Road In December 2005, NRG entered into a purchase and sale agreements (PSA) with Dynegy, Inc. whereby we have agreed to sell to Dynegy our 50% ownership interest in Rocky Road Power LLC for $45 million cash. As a result of the PSA with Dynegy, during December 2005, we recorded an impairment charge of approximately $20 million to write down the value of our 50% interest in Rocky Road to the fair value of $45 million.

Kendall In December 2004, we sold out interest in Kendall to LS Power Associates, L.P. or LS Power. Under the terms of the December 2004 agreement, we retained the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount, or the Call Option. Therefore, the transaction was treated as a partial sale for accounting purposes. On August 8, 2005, we executed an agreement with LS Power to sell the Call Option for $5 million. A pre-tax gain of $4 million was recognized in the third quarter of 2005.

Enfield On April 1, 2005, we completed the sale of our 25% interest in Enfield to Infrastructure Alliance Limited. The sale resulted in net pre-tax proceeds of $65 million. A pre-tax gain of approximately $12 million was recorded in the second quarter of 2005.

Commonwealth Atlantic Limited Partnership (CALP) In June 2004, we executed an agreement to sell our 50% interest in CALP. During the third quarter of 2004, we recorded an impairment charge of approximately $4 million to write down the value of our investment in CALP to its fair value. The sale closed in November 2004 resulting in net cash proceeds of $15 million. Total impairment charges as a result of the sale were approximately $5 million.

James River Power LLC In September 2004, we executed an agreement with Colonial Power Company LLC to sell all of our outstanding shares of stock in Capistrano Cogeneration Company, a wholly-owned subsidiary of NRG Energy which owns a 50% interest in James River Cogeneration Company at which time we recorded an impairment charge of approximately $6 million to write down the value of our investment in James River to its fair value. During the fourth quarter of 2004, the sales agreement was terminated. Total impairment charges for 2004 were approximately $7 million.

NEO Corporation On September 30, 2004, we completed the sale of several NEO investments Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. The sale also included four wholly-owned NEO subsidiaries (see Note 6). We received cash proceeds of approximately $6 million. The sale resulted in a loss of approximately $4 million attributable to the equity investment entities sold.

Calpine Cogeneration In January 2004, we executed an agreement to sell our 20% interest in Calpine Cogeneration Corporation to Calpine Power Company. The transaction closed in March 2004 and resulted in net cash proceeds of $3 million. During the second quarter of 2004, we received additional consideration on the sale of $1 million, resulting in an adjusted net gain of $1 million.

NLGI Minnesota Methane . We recorded an impairment charge of $15 million during the first quarter of 2003. This charge was related to a revised project outlook and management s belief that the decline in fair value was other than temporary. In May 2003, the project lenders to the wholly-owned subsidiaries of NEO Landfill Gas, Inc. and Minnesota Methane LLC foreclosed on our membership interest in the NEO Landfill Gas, Inc. subsidiaries and our equity interest in Minnesota Methane LLC. Upon completion of the foreclosure, we recorded a gain of $2 million resulting in a net impairment charge of $12 million. The gain upon completion of the foreclosure resulted from the release of certain obligations upon completion of the foreclosure.

NLGI MM Biogas In November 2003, we entered into a sales agreement with Cambrian Energy Development to sell our 50% interest in MM Biogas. We recorded an impairment charge of $3 million during the fourth quarter of 2003 due to developments related to the sale that indicated an impairment of our book value that was considered to be other than temporary.

ECKG In September 2002, we announced that we had reached agreement to sell our 44.5% interest in the ECKG power station in connection with our Csepel power generating facilities, and our interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland.

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The transaction closed in January 2003 and resulted in cash proceeds of $65 million and a net loss of less than $1 million. In accordance with the purchase agreement, we were to receive additional consideration if Atel purchased shares held by our partner. During the second quarter of 2003, we received approximately $4 million of additional consideration resulting in a net gain of approximately $3 million.

Loy Yang In May 2003, we entered into negotiations that culminated in the completion of a Share Purchase Agreement to sell 100% of the Loy Yang project. Consequently, we recorded an impairment charge of approximately $146 million during 2003. In April 2004 we completed the sale of Loy Yang which resulted in net cash proceeds of approximately $27 million and a loss of approximately $1 million.

Mustang Station On July 7, 2003, we completed the sale of our 25% interest in Mustang Station, a gas-fired combined cycle power generating plant located in Denver City, Texas, to EIF Mustang Holdings I, LLC. The sale resulted in net cash proceeds of approximately $13 million and a net gain of approximately $12 million.

Note 8 Other Charges (Credits)

Other charges and credits included in operating expenses in the Consolidated Statement of Operations include the following:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Corporate relocation charges	$ 6	$ 16	$	$
Reorganization items		(13)	2	198
Impairment charges	6	45		229
Restructuring charges				8
Fresh Start adjustments				(4,220)
Legal settlement				463
Total	$ 12	$ 48	$ 2	$ (3,322)

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. As of December 31, 2004, the transition of our corporate headquarters is substantially complete.

For the years ended December 31, 2005 and 2004, we recorded $6 million and $16 million, respectively, for total charges of $22 million related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs and lease abandonment costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, or SFAS 146. All material expenses related to the corporate relocation have been incurred as of December 31, 2005. Lease termination costs require that cash payments in the amount of $2 million be made through the fourth quarter of 2006.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the SFAS 146-classified expenses is as follows:

	Year Ended December 31, 2004	Year Ended December 31, 2005	Yet to be Incurred	Expected Total Charges
		(In millions)		
Employee related transition costs	$ 9	$ 2	$	$ 11
Severance and termination benefits	6	1		7
Lease termination costs	1	3		4
Total corporate relocation charges	$ 16	$ 6	$	$ 22

A summary of the significant components of the restructuring liability is as follows:

	Balance at December 31, 2004	Relocation Related Charges	Cash Payments	Balance at December 31, 2005
		(In millions)		
Employee related transition costs	$ (1)	$ 2	$ (1)	$
Severance and termination benefits	4	1	(5)	
Lease termination costs	1	3	(2)	2
Total	$ 4	$ 6	$ (8)	$ 2

As of December 31, 2005 and 2004, the net restructuring liability was approximately $2 million and $4 million, respectively, the majority of which is included in other current liabilities on the consolidated balance sheet. Charges related to the employee related transition costs, severance and termination benefits and lease termination costs are recorded at our corporate level within our All Other Other segment, in the corporate relocation charges line on the consolidated statement of operations.

Reorganization Items

For the year ended December 31, 2005 we did not record any reorganization item expense or income. For the year ended December 31, 2004, we recorded a net credit of approximately $13 million related primarily to the settlement of obligations recorded under Fresh Start. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred approximately $2 million and $198 million,

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respectively, in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred.

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Reorganization items				
Professional fees	$	$ 7	$ 2	$ 82
Deferred financing costs				55
Pre-payment settlement				20
Interest earned on accumulated cash				(1)
Contingent equity obligation				42
Settlement of obligations and other gains		(20)		
Total reorganization items	$	$ (13)	$ 2	$ 198

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS 144. As a result of this review, we recorded impairment charges of approximately $6 million, $45 million and $229 million, for the years ended December 31, 2005 and 2004, and the period January 1, 2003 through December 5, 2003, respectively, as shown in the table below.

To determine whether an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value.

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Impairment charges (credits) included the following asset impairments (realized gains) for the years ended December 31, 2005 and 2004, and the period January 1, 2003 to December 5, 2003. There were no impairment charges for the period December 6, 2003 to December 31, 2003.

		Reorganized NRG		Predecessor Company	
Project Name	Project Status	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period January 1 December 5, 2003	Fair Value Basis
		(In millions)			
Berrians I Gas Turbine Power LLC	Non-operating asset	$ 6	$	$	Sales price
Meriden (turbine only)	Pending sale		15		Sales price
Kendall	Sold		27		Realized loss
Louisiana Generating LLC	Office building and land being marketed		1		Estimated market price
New Roads Holding LLC (turbine)	Non-operating asset abandoned		2		Projected cash flows
Devon Power LLC	Operating at a loss in 2003			64	Projected cash flows
Middletown Power LLC	Operating at a loss Terminated			157	Projected cash flows
Arthur Kill Power, LLC	construction project			9	Projected cash flows
Langage (UK)	Terminated			(3)	Estimated market price/Realized gain
Turbines	Sold			(22)	Realized gain
Berrians Project	Terminated			14	Realized loss
TermoRio	Terminated			7	Realized loss
Other				3	
Total impairment charges		$ 6	$ 45	$ 229	

Berrians I Gas Turbine Power LLC During 2005, we determined that an unused turbine previously acquired for a now canceled project would be placed for sale. A letter of intent was entered into for the sale which resulted in an impairment of approximately $6 million, and the sale closed during the first quarter of 2006. Berrians is included within our Other North America segment. The balance of the Berrians turbine is classified as a current asset held for sale on the balance sheet as of December 31, 2005, totaling $8 million.

Meriden Duri