NRG ENERGY, INC.
Form 424B5
January 27, 2006

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Filed pursuant to Rule 424(b)(5)
Registration No. 333-130549

A filing fee of $61,525.00, calculated in accordance with Rule 457(r), has been transmitted to the SEC in connection with the securities offered by means of this prospectus supplement. This fee includes the mandatory convertible preferred stock issuable upon the exercise of the underwriters over-allotment option.

PROSPECTUS SUPPLEMENT
(To Prospectus dated December 21, 2005)

2,000,000 Shares
NRG Energy, Inc.
5.75% Mandatory Convertible Preferred Stock

We are offering 2,000,000 shares of our 5.75% mandatory convertible preferred stock by this prospectus supplement and the accompanying prospectus. The closing of this offering is not conditioned on the consummation of our acquisition of Texas Genco LLC described elsewhere in this prospectus supplement. Concurrently with this offering, we are offering senior notes and shares of our common stock. This offering is not conditioned on the consummation of these concurrent offerings.

We will pay dividends on each share of our mandatory convertible preferred stock in an annual amount of $14.375. Dividends will accrue and cumulate from the date of issuance and, to the extent that we are legally permitted to pay dividends and our board of directors, or an authorized committee of our board of directors, declares a dividend payable, we will pay dividends in cash on March 15, June 15, September 15 and December 15 of each year prior to March 15, 2009, or the following business day if the 15th is not a business day and on the mandatory conversion date. The first dividend payment will be made on March 15, 2006 in the amount of $1.7170 per share of our mandatory convertible preferred stock, which reflects the time period from the date of issuance to March 14, 2006.

Each share of our mandatory convertible preferred stock has a liquidation preference of $250, plus accrued, cumulated and unpaid dividends. Each share of our mandatory convertible preferred stock will automatically convert on March 16, 2009, into between 4.1356 and 5.1282 shares of our common stock, subject to anti-dilution adjustments, depending on the average closing price per share of our common stock over the 20 trading day period ending on the third trading day prior to such date. At any time prior to March 16, 2009, holders may elect to convert each share of our mandatory convertible preferred stock into 4.1356 shares of our common stock, subject to anti-dilution adjustments. If the closing price per share of our common stock exceeds $90.675 for at least 20 trading days within a period of 30 consecutive trading days, we may elect, subject to certain limitations, to cause the conversion of all, but not less than all, of the shares of mandatory convertible preferred stock then outstanding at the conversion rate of 4.1356 shares of our common stock per share of our mandatory convertible preferred stock, provided that at the time of such conversion we are then legally permitted to and do pay an amount equal to any accrued, cumulated and unpaid dividends plus the present value of all remaining future dividend payments at that time.

Prior to this offering, there has been no public market for our mandatory convertible preferred stock. We have applied to list our mandatory convertible preferred stock on the New York Stock Exchange under the symbol NRGPra . Shares of our common stock are listed on the New York Stock Exchange under the symbol NRG. The last reported sale price of shares of our common stock on January 25, 2006 was $49.25 per share.

Investing in our mandatory convertible preferred stock involves risks. See Risk Factors on page S-17 of this prospectus supplement.

Neither the Securities and Exchange Commission nor any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus supplement or the accompanying prospectus. Any representation to the contrary is a criminal offense.

	Per Share	Total
Initial price to the public	*$ 250*	*$ 500,000,000*

Underwriting discount	*$*	*6.875*	*$*	*13,750,000*
Proceeds, before expenses, to NRG Energy, Inc.	*$*	*243.125*	*$*	*486,250,000*

To the extent the underwriters sell more than 2,000,000 shares of our mandatory convertible preferred stock, the underwriters have the option to purchase up to 300,000 additional shares of our mandatory convertible preferred stock from us within 30 days of the date of this prospectus supplement at the initial price to the public less the underwriting discount.

The mandatory convertible preferred stock will be taken for delivery on or about February 2, 2006.

Joint Book-Running Managers

MORGAN STANLEY *CITIGROUP*

LEHMAN BROTHERS

BANC OF AMERICA SECURITIES LLC

DEUTSCHE BANK SECURITIES

GOLDMAN, SACHS & CO.

MERRILL LYNCH & CO.

The date of this prospectus supplement is January 26, 2006.

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About This Prospectus Supplement

This document consists of two parts. The first part is this prospectus supplement, which describes the specific terms of this offering. The second part is the accompanying prospectus, which describes more general information, some of which may not apply to this offering. You should read both this prospectus supplement and the accompanying prospectus, together with additional information described below under the headings Where You Can Find More Information and Incorporation of Certain Documents by Reference.

If the description of the offering varies between this prospectus supplement and the accompanying prospectus, you should rely on the information in this prospectus supplement.

Any statement made in this prospectus supplement or in a document incorporated or deemed to be incorporated by reference in this prospectus supplement will be deemed to be modified or superseded for purposes of this prospectus supplement to the extent that a statement contained in this prospectus supplement or in any other subsequently filed document that is also incorporated or deemed to be incorporated by reference in this prospectus supplement modifies or supersedes that statement. Any statement so modified or superseded will not be deemed, except as so modified or superseded, to constitute a part of this prospectus supplement. See Incorporation of Certain Documents By Reference.

Where You Can Find More Information

NRG files annual, quarterly and special reports, proxy statements and other information with the Securities and Exchange Commission, or the SEC. You can inspect and copy these reports, proxy statements and other information at the Public Reference Room of the SEC, 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference room. NRG s SEC filings will also be available to you on the SEC s website at http://www.sec.gov and through the New York Stock Exchange, 20 Broad Street, New York, NY 10005, on which NRG s common stock is listed.

This prospectus supplement and the accompanying prospectus, which forms a part of the registration statement, do not contain all the information that is included in the registration statement. You will find additional information about us in the registration statement. Any statements made in this prospectus supplement or the accompanying prospectus concerning the provisions of legal documents are not necessarily complete and you should read the documents that are filed as exhibits to the registration statement or otherwise filed with the SEC for a more complete understanding of the document or matter.

Incorporation of Certain Documents by Reference

The SEC allows the incorporation by reference of the information filed by NRG with the SEC into this prospectus supplement, which means that important information can be disclosed to you by referring you to those documents and those documents will be considered part of this prospectus supplement. Information that NRG files later with the SEC will automatically update and supersede the previously filed information. The documents listed below and any future filings NRG makes with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, are incorporated by reference herein, after the date of this prospectus supplement but before the end of any offering made under this prospectus supplement:

1. NRG s annual report on Form 10-K for the year ended December 31, 2004 filed on March 30, 2005 as amended by the current report on Form 8-K filed on December 20, 2005.

2. NRG s Definitive Proxy Statement on Schedule 14A filed on April 12, 2005.

3. NRG s quarterly reports on Form 10-Q for the quarters ended March 31, 2005 (filed on May 10, 2005), June 30, 2005 (filed on August 9, 2005) and September 30, 2005 (filed on November 7, 2005).

4. NRG s current reports on Form 8-K filed on February 24, 2005, Form 8-K filed on March 3, 2005, two Forms 8-K filed on March 30, 2005 (which do not include information deemed furnished), Form 8-K filed on May 24, 2005, Form 8-K/ A filed on May 24, 2005, Form 8-K/ A filed on May 25, 2005, Form 8-K filed on June 15, 2005, Form 8-K/ A filed on June 15, 2005, Form 8-K filed on June 17,

2005, Form 8-K filed on July 18, 2005, Form 8-K filed on August 1, 2005, Form 8-K filed on August 3, 2005, Form 8-K filed on August 9, 2005 (which does not include information deemed furnished), Form 8-K filed on August 11, 2005, Form 8-K filed on September 1, 2005, Form 8-K filed on September 7, 2005 (which does not include information deemed furnished), Form 8-K filed on October 3, 2005, Form 8-K filed on October 12, 2005, Form 8-K filed on November 7, 2005 (which does not include information deemed furnished), Form 8-K filed on December 20, 2005, Form 8-K filed on December 21, 2005, Form 8-K filed on December 28, 2005 (which does not include information deemed furnished), Form 8-K filed on January 4, 2006, Form 8-K filed on January 5, 2006, Form 8-K/ A filed on January 5, 2006, Form 8-K filed on January 13, 2006, Form 8-K filed on January 23, 2006, Form 8-K/A filed on January 23, 2006 and Form 8-K/A filed on January 26, 2006.

5. The description of NRG s common stock contained in the Registration Statement on Form 8-A dated March 22, 2004 filed with the SEC to register such securities under the Securities and Exchange Act of 1934, as amended, including any amendment or report filed for the purpose of updating such description.

If you make a request for such information in writing or by telephone, NRG will provide you, without charge, a copy of any or all of the information incorporated by reference in this prospectus. Any such request should be directed to:

NRG Energy, Inc.
211 Carnegie Center
Princeton, New Jersey 08540
(609) 524-4500
Attention: General Counsel

You should rely only on the information contained in this prospectus supplement, the attached prospectus, the documents incorporated by reference and any written communication from us or the underwriters specifying the final terms of the offering. NRG has not, and the underwriters have not, authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. NRG is not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where the offer or sale is not permitted. You should assume that the information appearing in this prospectus supplement is accurate as of the date on the front cover of this prospectus supplement only. NRG s business, financial condition, results of operations and prospects may have changed since that date.

Disclosure Regarding Forward-Looking Statements

This prospectus supplement contains, and the documents incorporated by reference herein may contain, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Such forward-looking statements are subject to certain risks, uncertainties and assumptions that include, but are not limited to, expected earnings and cash flows, future growth and financial performance and the expected synergies and other benefits of the acquisition of Texas Genco LLC described herein and typically can be identified by the use of words such as will, expect, estimate, anticipate, forecast, plan, similar terms. Although we believe that our expectations are reasonable, we can give no assurance that these expectations will prove to have been correct, and actual results may vary materially. Factors that could cause actual results to differ materially from those contemplated above include, among others:

- Risks and uncertainties related to the capital markets generally, including increases in interest rates and the availability of financing for the acquisition of Texas Genco LLC;

- NRG s indebtedness and the additional indebtedness that it will incur in connection with the acquisition of Texas Genco LLC;

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NRG s ability to successfully complete the acquisition of Texas Genco LLC, regulatory or other limitations that may be imposed as a result of the acquisition of Texas Genco LLC, and the success of the business following the acquisition of Texas Genco LLC;

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;

NRG s potential inability to enter into contracts to sell power and procure fuel on terms and prices acceptable to it;

The liquidity and competitiveness of wholesale markets for energy commodities;

Changes in government regulation, including possible 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 or designs employed by independent system operators, or ISOs, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate our generation units for all of their costs;

NRG s ability to realize its significant deferred tax assets, including loss carry forwards;

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

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

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

Significant operating and financial restrictions which may be placed on NRG as a result of the financing transactions described elsewhere in this prospectus supplement.

Market and Industry Data

Certain market and industry data included or incorporated by reference in this prospectus supplement and in the accompanying prospectus has been obtained from third party sources that we believe to be reliable. We have not independently verified such third party information and cannot assure you of its accuracy or completeness. While we are not aware of any misstatements regarding any market, industry or similar data presented herein, such data involves risks and uncertainties and is subject to change based on various factors, including those discussed under the headings Disclosure Regarding Forward-Looking Statements and Risk Factors in this prospectus supplement.

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SUMMARY

This summary may not contain all the information that may be important to you. You should read this entire prospectus supplement, the accompanying prospectus and those documents incorporated by reference into this prospectus supplement and the accompanying prospectus, including the risk factors and the financial data and related notes, before making an investment decision.

In this prospectus supplement, unless otherwise indicated herein or the context otherwise indicates:

the term NRG refers to NRG Energy, Inc., together with its consolidated subsidiaries;

the term Texas Genco refers to Texas Genco LLC, together with its consolidated subsidiaries;

the term Acquisition refers to the purchase by NRG of all the outstanding equity interests of Texas Genco, pursuant to the acquisition agreement, dated as of September 30, 2005, between NRG, Texas Genco and the sellers named therein;

the term Financing Transactions refers to this offering, the concurrent offering by NRG of its common stock and its fixed rate senior notes due 2014, or the 2014 fixed rate notes and fixed rate senior notes due 2016, or the 2016 fixed rate notes, together, the senior notes, and the application of the net proceeds therefrom, and the execution of NRG s new senior secured credit facility and the application of the initial borrowings thereunder, each as described elsewhere in this prospectus supplement;

the term Transactions refers to the Acquisition, the Financing Transactions, the pending sale of Audrain Generating LLC, the pending acquisition of 50% interest in WCP (Generation) Holdings LLC and the pending sale of our 50% ownership interest in Rocky Road Power LLC, or Rocky Road;

the terms we , our , us , the combined company and the Company refer to NRG and Texas Genco on a co basis, together with their consolidated subsidiaries, after giving pro forma effect to the completion of the Acquisition and the Financing Transactions;

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 September 30, 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 MW and MWh figures and other operational figures related to the combined company only give pro forma effect to the Acquisition and the Financing Transactions; and

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).

Our Business

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 of energy, capacity and related products in the competitive markets in which we operate. As of September 30, 2005, the combined company would have had a total global portfolio of 235 operating generation units at 62 power generation plants, with an aggregate generation capacity of approximately 25,041 MW. Within the United States, the combined company will have one of the largest and most diversified power generation portfolios with approximately 23,124 MW of generation capacity in 213 generating units at 54 plants as of September 30, 2005. These power generation facilities are primarily located in our core regions in the Electric Reliability Council of Texas, or ERCOT, market (approximately 11,119 MW), and in the Northeast (approximately 7,099 MW), South Central (approximately 2,395 MW)

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and Western (approximately 1,044 MW) regions of the United States. Our facilities consist primarily of baseload, intermediate and peaking power generation facilities, which we refer to as the merit order, 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.

The Texas Genco Acquisition

On September 30, 2005, NRG entered into an acquisition agreement, or the Acquisition Agreement, with Texas Genco and each of the direct and indirect owners of equity interests in Texas Genco, or the Sellers. Pursuant to the Acquisition Agreement, NRG agreed to purchase all of the outstanding equity interests in Texas Genco for a total pro forma purchase price of approximately $6.121 billion that includes the assumption of approximately $2.7 billion of indebtedness. The purchase price is subject to adjustment, and includes an equity component valued at approximately $2.0 billion based on a price per share of $45.37 of NRG s common stock issued to the Sellers, and an average price per share of $40.73 for the consideration with a fair value of $368 million, or the Other Consideration. As a result of the Acquisition, Texas Genco will become a wholly-owned subsidiary of NRG. Each of NRG s and the Sellers obligation to consummate the Acquisition is subject to certain customary conditions, including the receipt of required regulatory consents and approvals. See The Acquisition for a discussion of the Acquisition.

The closing of this offering is not conditioned on the consummation of the Acquisition. While we expect that the Acquisition will be consummated in or about the first week of February 2006, no assurance can be given that the Acquisition will be completed in accordance with the anticipated timing or at all. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay.

Our Strategy

Our strategy is to increase the value of, and extract value from, 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 who offer load, or otherwise consume wholesale electricity products and services in bulk. Our strategy includes the following elements:

Increase value from our existing assets. Following the Acquisition, we believe that we will 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 believe that 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 the merit order.

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 intend to 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 leveraging 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.

Our Competitive Strengths

Scale and diversity of assets. The combined company will have one of the largest and most diversified power generation portfolios in the United States with approximately 23,124 MW of generation capacity in 213 generating units at 54 plants as of September 30, 2005. Our power generation assets will be diversified by fuel type, dispatch level and region, which will help mitigate the risks associated with fuel price volatility and market demand cycles. The combined company s U.S. baseload facilities, which will consist of approximately 8,558 MW of generation capacity measured as of September 30, 2005, will provide the combined company with a significant source of stable cash flow, while the combined company s intermediate and peaking facilities, with approximately 14,566 MW of generation capacity as of September 30, 2005, will 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 will have dual or multiple fuel capability, which will allow most of these plants to dispatch with the lowest cost fuel option.

Reliability of future cash flows. We have sold forward a significant amount of our expected baseload generation capacity for 2006 and 2007. As of September 30, 2005 the combined company would have sold forward 68% of its baseload generation in the Texas (ERCOT) market for 2006 through 2009. As of the same date, the combined company would have sold approximately 83% of its expected annual baseload generation in the Southeastern Electric Reliability Council/ Entergy, or SERC Entergy, market for 2006 through 2009, and approximately 70% of its expected annual baseload generation in the Northeast region for 2006. In addition, as of September 30, 2005, the combined company would have purchased forward under fixed price 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 September 30, 2005, approximately 38% of the combined company s domestic generation capacity would have 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 that currently have substantially higher variable costs than our solid fuel baseload power plants. For example, in the ERCOT market, a 2004 report by Henwood Energy Services, Inc., or Henwood, found that natural gas-fired power plants set the market price of power more than 90% of the time. 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 combined company will have 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 others, selling power at prevailing market prices during periods of peak demand and providing ancillary services in support of system reliability.

Summary of Risk Factors

We are subject to a variety of risks related to our competitive position and business strategies. Some of the more significant challenges and risks include those associated with the operation of our power generation plants, volatility in power prices and fuel costs, our leveraged capital structure and extensive governmental regulation. See Risk Factors beginning on page S-17 for a discussion of the factors you should consider before investing in our securities.

The Financing Transactions

The offering of mandatory convertible preferred stock forms part of a larger financing plan for the Acquisition described elsewhere in this prospectus supplement. See The Acquisition. Concurrently with this offering, NRG intends to offer, by means of separate prospectus supplements (i) $1.0 billion of its common stock and (ii) $3.6 billion of its senior notes, or the New Senior Notes. See Description of Capital Stock Common Stock and Description of Certain Indebtedness New Senior Notes. This offering, the common stock offering and the New Senior Notes offering are expected to be consummated at or prior to the completion of the Acquisition. The closing of this offering will not necessarily be contemporaneous with the closing of the common stock offering and/or the closing of the New Senior Notes offering. The net proceeds of the offering of the New Senior Notes (after payment of underwriting discounts and commissions) will be placed into an escrow account held by the escrow agent until the consummation of the Acquisition.

In addition, NRG intends to enter into a new senior secured credit facility at or prior to the closing of the Acquisition that will replace its existing senior secured credit facility. See Description of Certain Indebtedness New Senior Secured Credit Facility. Concurrently with this offering, NRG is conducting a cash tender offer and consent solicitation with respect to (i) all of its outstanding 8% Second Priority Senior Secured Notes due 2013, or the Second Priority Notes, and (ii) all of Texas Genco s outstanding 6.875% Senior Notes due 2014, or the Unsecured Senior Notes. The completion of the Acquisition is not conditioned on the completion of the tender offer or receipt of the consents for either the Second Priority Notes or Texas Genco s Unsecured Senior Notes. The completion of the tender offer for the Second Priority Notes and Texas Genco s Unsecured Senior Notes is conditioned on the completion of the Acquisition. However, NRG can waive this condition in the case of the tender offer and consent solicitation for the Second Priority Notes.

NRG intends to use initial borrowings under its new senior secured credit facility, together with the net proceeds from this offering, the offerings of common stock and New Senior Notes and cash on hand (i) to finance the Acquisition, (ii) to repurchase NRG s outstanding Second Priority Notes, (iii) to repurchase Texas Genco s outstanding Unsecured Senior Notes, (iv) to repay amounts outstanding under NRG s existing senior secured credit facility and Texas Genco s existing senior secured credit facility, (v) for ongoing credit needs of the combined company, including replacement of existing letters of credit and (vi) to pay related premiums, fees and expenses. In the event that NRG does not consummate the Acquisition, NRG intends to use the net proceeds from this offering for general corporate purposes. See Use of Proceeds.

The closing of this offering is not contingent on the closing of the common stock offering, the closing of the New Senior Notes offering, the effectiveness of the new senior secured credit facility, the completion of the tender offers and receipt of the consents in connection with the outstanding tender offers for NRG s and

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Texas Genco s notes or the consummation of the Acquisition. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay. NRG s obligations under the Acquisition Agreement are not conditioned upon the consummation of any or all of the Financing Transactions.

NRG has entered into an amended and restated commitment letter, or the commitment letter, with Morgan Stanley Senior Funding, Inc., Citigroup Global Markets Inc., Lehman Commercial Paper Inc., Lehman Brothers Inc., Banc of America Bridge LLC, Deutsche Bank AG Cayman Islands Branch, Merrill Lynch Capital Corporation and Goldman Sachs Credit Partners L.P., or the bridge lenders. Under the commitment letter, the bridge lenders have committed to fund NRG s new senior secured credit facility and to provide, subject to certain conditions, the additional financing required for the Acquisition through a $5.1 billion bridge loan facility in the event that sufficient proceeds are not raised from this offering, the common stock offering and/or the New Senior Notes offering. See Description of Certain Indebtedness Bridge Loan Facility. In the event that NRG is unable to raise sufficient proceeds through the consummation of this offering, the common stock offering and the New Senior Notes offering, NRG may draw down on the bridge loan facility, in whole or in part, in order to finance the Acquisition. In the event that NRG does not consummate the common stock offering and/or the New Senior Notes offering as currently contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis.

Sources and Uses of Funds

The following table sets forth the expected sources and uses of funds in connection with the Acquisition on a pro forma basis giving effect to the Transactions as if they occurred on September 30, 2005. No assurances can be given that the information in the following table will not change depending on the nature of our financings. See Risk Factors Risks Related to the Acquisition Because the historical and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement 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, Texas Genco and your investment decision and Risk Factors Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business.

Sources[1]	Amount (in millions)
Gross proceeds of mandatory convertible preferred stock offering	$ 500
New senior secured term loan facility	3,575
Cash released from canceling existing funded letter of credit facility[3]	350
Gross proceeds of common stock offering	1,016
Common stock consideration to be issued to Sellers	1,606[2]
Gross proceeds of 2014 fixed rate notes offering	1,200
Gross proceeds of 2016 fixed rate notes offering	2,400
NRG s cash on hand	373
Total	$ 11,020

Uses		Amount (in millions)
Purchase price less acquisition costs[2]		$ 6,005
Texas Genco s cash on hand to reduce consideration		(222)
Refinancing:		
Repayment of NRG s existing credit facilities[3]	877	
Repayment of Texas Genco s existing credit facilities[4]	1,614	
Total repayment of existing credit facilities		2,491
Repurchase of NRG s Second Priority Notes[5]		1,080
Repurchase of Texas Genco s Unsecured Senior Notes[6]		1,125
Accrued interest for NRG and Texas Genco outstanding debt		52
Estimated underwriting commissions, tender offer premiums, fees and expenses		489
Total		$ 11,020

(1) NRG has entered into the commitment letter with the bridge lenders pursuant to which the bridge lenders have committed to fund NRG s new senior secured credit facility and to provide, subject to certain conditions, the additional financing required for the Acquisition through a $5.1 billion bridge loan facility in the event that this offering, the common stock offering and/or the New Senior Notes offering are not consummated. In the event that NRG is unable to raise sufficient proceeds through the consummation of this offering, the common stock offering and/or the New Senior Notes offering, NRG may draw down on the bridge loan facility, in whole or in part, in order to finance the Acquisition. In the event that NRG does not consummate the common stock offering and the New Senior Notes offering as currently contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis.

(2) The common stock component of the consideration for the Acquisition is based on a fair value of $45.37 per share of NRG s common stock and consideration with a fair value of $368 million, or the Other Consideration, which

may be comprised either of an additional 9,038,125 shares of common stock, additional cash, shares of a new series of NRG s Cumulative Preferred Stock or a combination of the foregoing. This fair value is based on an average stock price of $40.73, as prescribed by the Acquisition Agreement. The Company has elected to pay this amount in cash. This is because the foregoing table is based on a pro forma closing date of the Acquisition of September 30, 2005. To the extent the fair value of NRG s common stock price for purposes of the equity component, and Texas Genco s cash on hand is different at closing of the Acquisition, this amount and the purchase price for the Acquisition will be adjusted accordingly.

(3) Before giving effect to the Acquisition and the Financing Transactions, as of September 30, 2005, NRG had $876.6 million of outstanding indebtedness under its amended and restated credit facility, which consisted of (a) $446.6 million in term loans outstanding, which term loans provide for interest at a rate of LIBOR (4.02% at September 30, 2005) plus 187.5 basis points payable quarterly and mature on December 24, 2011, (b) $80.0 million in principal amount outstanding under the revolving credit facility, which provides for interest at a rate of LIBOR (3.83% at September 30, 2005) plus 2.5% and matures on December 24, 2007 and (c) $350.0 million outstanding under the funded letter of credit facility, which provide for a participation fee of 1.875%, a deposit fee of 0.10%, and an issuance fee of 0.25%, and matures on December 24, 2011.

(4) Before giving effect to the Acquisition and Financing Transactions, as of September 30, 2005, Texas Genco had $1,614 million in term loans outstanding under its existing senior secured credit facility, which term loans provide for interest at a rate of 5.94% (as of September 30, 2005) payable at least quarterly and mature in December 2011.

(5) Before giving effect to the Acquisition and Financing Transactions, as of September 30, 2005, NRG had $1.08 billion of Second Priority Notes outstanding, which provide for cash interest at 8.0% per annum payable semiannually.

(6) Before giving effect to the Acquisition and Financing Transactions, as of September 30, 2005, Texas Genco had $1.125 billion of Unsecured Senior Notes outstanding, which provide for cash interest at 6.875% per annum payable semiannually.

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Recent Developments

Acquisitions and Dispositions

We anticipate that the following transactions will be consummated after the Acquisition and Financing Transactions.

On December 8, 2005, NRG entered into an asset purchase and sale agreement to sell NRG Audrain Generating LLC, or Audrain, a gas fired 577 MW peaking facility in Vandalia, Missouri to AmerenUE, a subsidiary of Ameren Corporation. The purchase price is $115 million, subject to customary purchase price adjustments, plus the assumption of $240 million of non-recourse capital lease obligations and assignment of $240 million note receivable. Of the $115 million in cash proceeds, approximately $93 million of the proceeds will be paid to the project lenders with the balance of approximately $22 million paid to NRG. This transaction, which is subject to regulatory approval, is expected to close during the first half of 2006.

On December 27, 2005, NRG entered into two purchase and sale agreements with Dynegy Inc., or Dynegy, through which the companies will each simultaneously purchase the other s interest in two jointly held entities that own power generation facilities in the states of California and Illinois, respectively. Under the purchase and sale agreement for the California interests, NRG will acquire Dynegy s 50% interest in WCP (Generation) Holdings LLC, or WCP Holdings, for a purchase price of $205 million. As a result of this transaction, NRG will become the sole owner of power plants totaling approximately 1,800 MW in southern California. Pursuant to the terms of the purchase and sale agreement for the Illinois interests, NRG will sell to Dynegy its 50% ownership interest in the jointly held entity that owns the Rocky Road power plant, a 330 MW natural gas-fired peaking facility near Chicago, for a purchase price of $45 million. NRG will effectively fund the net purchase price of $160 million with cash held by West Coast Power LLC, or WCP. The transactions, which are conditioned upon each other and subject to regulatory approval, are expected to close in the first quarter of 2006.

These transactions have been reflected in our pro forma financial statements as filed on our amended Current Report on Form 8-K/A filed on January 23, 2006 and on our amended Current Report on Form 8-K/A filed on January 26, 2006 and incorporated herein by reference.

Tender Offers and Consent Solicitations

On January 24, 2006, NRG announced that it had received valid tenders and consents from holders of approximately $1,078,141,353 in aggregate principal amount of Second Priority Notes and $1,125,000,000 in aggregate principal amount of Unsecured Senior Notes, representing approximately 99.78% and 100% of the outstanding Second Priority Notes and Unsecured Senior Notes, respectively, in connection with the cash tender offer and consent solicitation for the Second Priority Notes and the Unsecured Senior Notes. Consummation of the tenders offers are conditioned upon the satisfaction of certain conditions.

NRG Energy, Inc. is a Delaware corporation. Our principal executive office is located at 211 Carnegie Center, Princeton, New Jersey 08540, and our telephone number at that address is (609) 524-4500. Our website is located at www.nrgenergy.com. The information on, or linked to, our website is not part of this prospectus supplement.

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The Offering

Issuer	NRG Energy, Inc.
Securities Offered	2,000,000 shares of 5.75% mandatory convertible preferred stock, which we refer to in this prospectus supplement as the mandatory convertible preferred stock.
Initial Offering Price	$250 for each share of mandatory convertible preferred stock.
Option to Purchase Additional Shares of Mandatory Convertible Preferred Stock	To the extent the underwriters sell more than 2,000,000 shares of our mandatory convertible preferred stock, the underwriters have the option to purchase up to 300,000 additional shares of our mandatory convertible preferred stock from us at the initial offering price, less underwriting discounts and commissions, within 30 days from the date of this prospectus supplement. If the underwriters exercise their option to purchase additional shares of our mandatory convertible preferred stock in full, we will have 2,300,000 shares of our mandatory convertible preferred stock outstanding.
Dividends	$14.375 for each share of our mandatory convertible preferred stock per year. Dividends will accrue and cumulate from the date of issuance and, to the extent that we are legally permitted to pay dividends and our board of directors, or an authorized committee of our board of directors, declares a dividend payable, we will pay dividends in cash on each dividend payment date. The dividend payable on the first dividend payment date is $1.7170 per share and on each subsequent dividend payment date will be $3.59375 per share.
Dividend Payment Dates	March 15, June 15, September 15 and December 15 of each year (or the following business day if the 15th is not a business day) prior to the mandatory conversion date (as defined below), commencing on March 15, 2006 and on the mandatory conversion date.
Redemption	Our mandatory convertible preferred stock is not redeemable.
Mandatory Conversion Date	March 16, 2009, which we call the mandatory conversion date.
Mandatory Conversion	On the mandatory conversion date, each share of our mandatory convertible preferred stock will automatically convert into shares of our common stock, based on the conversion rate as described below. Holders of our mandatory convertible preferred stock on the mandatory conversion date will have the right to receive the cash dividend due on such date (including any accrued, cumulated and unpaid dividends on our mandatory convertible preferred stock as of the mandatory conversion date), whether or not declared (other than previously declared dividends on our mandatory convertible preferred stock payable to holders of record as of a

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prior date), to the extent we are legally permitted to pay such dividends at such time.

Conversion Rate

Except as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount, the conversion rate for each share of our mandatory convertible preferred stock will be not more than 5.1282 shares of our common stock and not less than 4.1356 shares of our common stock, depending on the applicable market value of shares of our common stock, as described below.

The applicable market value of shares of our common stock is the average of the closing prices of our common share on each of the 20 consecutive trading days ending on the third trading day immediately preceding the mandatory conversion date. Applicable market value will be calculated as described under Description of Mandatory Convertible Preferred Stock Mandatory Conversion.

The conversion rate is subject to certain adjustments, as described under Description of Mandatory Convertible Preferred Stock Anti-dilution Adjustments and Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount.

The following table illustrates the conversion rate per share of our mandatory convertible preferred stock (subject to certain adjustments described in this prospectus supplement).

Applicable Market Value on Conversion Date	Conversion Rate
equal to or greater than $60.45	4.1356
less than $60.45 but greater than $48.75	4.1356 to 5.1282
less than or equal to $48.75	5.1282

Optional Conversion

At any time prior to March 16, 2009, you may elect to convert each of your shares of our mandatory convertible preferred stock at the minimum conversion rate of 4.1356 shares of our common stock for each share of mandatory convertible preferred stock. This conversion rate is subject to certain adjustments as described in this prospectus supplement.

Provisional Conversion at Our Option

If, at any time prior to March 16, 2009, the closing price per share of our common stock exceeds $90.675(150% of the threshold appreciation price of $60.45), subject to adjustments described in this prospectus supplement, for at least 20 trading days within a period of 30 consecutive trading days, we may elect to cause the conversion of all, but not less than all, of our mandatory convertible preferred stock then outstanding at the minimum conversion rate of 4.1356 shares of our common stock for each share of mandatory convertible preferred stock (subject to certain adjust-

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	ments described in this prospectus supplement) only if, in addition to issuing you such shares of our common stock, at the time of such conversion we are then legally permitted to and pay you in cash (i) the present value of all the remaining future dividend payments through and including March 16, 2009, on our mandatory convertible preferred stock, computed using a discount rate equal to the treasury yield, plus (ii) an amount equal to any accrued, cumulated and unpaid dividend payments on our mandatory convertible preferred stock, whether or not declared (other than previously declared dividends on our mandatory convertible preferred stock payable to holders of record as of a prior date). See Description of Mandatory Convertible Preferred Stock Provisional Conversion at Our Option.
Conversion upon Cash Acquisition; Cash Acquisition Make-Whole Amount	If we are the subject of specified cash acquisitions on or prior to March 16, 2009, under certain circumstances, we will (1) permit conversion of our mandatory convertible preferred stock during the period beginning on the date that is 15 days prior to the anticipated effective date of the applicable cash acquisition and ending on the date that is 15 days after the actual effective date at a specified conversion rate determined by reference to the price per share of our common stock paid in such cash acquisition and (2) pay converting holders an amount equal to the sum of any accumulated and unpaid dividends on shares of our mandatory convertible preferred stock that are converted plus the present value of all remaining dividend payments on such shares through and including March 16, 2009, as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount. The applicable conversion rate will be determined based on the date such transaction becomes effective and the price paid per share of our common stock in such transaction. However, if such transaction constitutes a public acquirer change of control, in lieu of providing for conversion and paying the dividend amount, we may elect to adjust our conversion obligation such that upon conversion of the mandatory convertible preferred stock, we will deliver acquirer common stock as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount.
Anti-dilution Adjustments	The formula for determining the conversion rate and the number of shares of our common stock to be delivered upon conversion may be adjusted in the event of, among other things, stock dividends or distributions in shares of our common stock or subdivisions, splits and combinations of shares of our common stock. See Description of Mandatory Convertible Preferred Stock Anti-dilution Adjustments.
Liquidation Preference	$250 per share of mandatory convertible preferred stock, plus an amount equal to the sum of all accrued, cumulated and unpaid dividends.

Voting Rights

Holders of our mandatory convertible preferred stock will not be entitled to any voting rights, except as required by Delaware law and as described under Description of Mandatory Convertible Preferred Stock Voting Rights.

Ranking

Our mandatory convertible preferred stock, with respect to dividend rights and upon liquidation, winding up and dissolution, ranks:

junior to all our existing and future debt obligations;

junior to all senior stock, which is each class or series of our capital stock other than (i) our common stock and any other class or series of our capital stock the terms of which provide that such class or series will rank junior to the preferred stock and (ii) any other class or series of our capital stock the terms of which provide that such class or series will rank on a parity with the preferred stock;

on a parity with all parity stock, which includes our existing 4% Convertible Perpetual Preferred Stock, 3.625% Convertible Perpetual Preferred Stock and any class or series of our capital stock that has terms which provide that such class or series will rank on a parity with the preferred stock;

senior to all junior stock, which is our common stock and each class or series of our capital stock that has terms which provide that such class or series will rank junior to the preferred stock; and

effectively junior to all of our subsidiaries (i) existing and future liabilities and (ii) capital stock held by others.

We will not be entitled to issue any class or series of our capital stock the terms of which provide that such class or series will rank senior to our mandatory convertible preferred stock as to payment of dividends or distribution of assets upon our dissolution, liquidation or winding up without the approval of the holders of at least two-thirds of the shares of our mandatory convertible preferred stock then outstanding and any other shares of our preferred stock ranking on a parity with our mandatory convertible preferred stock then outstanding, voting together as a single class.

Listing

We have applied to list the mandatory convertible preferred stock on the New York Stock Exchange under the symbol NRGPra.

Use of Proceeds

We estimate that the net proceeds of this offering, after giving effect to underwriting discounts and estimated expenses payable by us, will be approximately $484.7 million. We intend to use the net proceeds from this offering and the offerings of common stock and the New Senior Notes, together with initial borrowings under our new senior secured credit facility and cash on hand, (i) to finance the Acquisition, (ii) to repurchase NRG s outstanding Second Priority Notes, (iii) to repurchase Texas Genco s outstanding Unsecured Senior Notes, (iv) to repay amounts out-

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standing under NRG s existing senior secured credit facility and Texas Genco s existing senior secured credit facility, (v) for ongoing credit needs of the combined company, including replacement of existing letters of credit and (vi) to pay related fees, premiums and expenses. See Use of Proceeds.

Unless otherwise stated, all information contained in this prospectus supplement assumes that the underwriters do not exercise their option to purchase additional shares of our mandatory convertible preferred stock.

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Summary Historical and Pro Forma Financial Information

The following table presents summary historical consolidated financial information of (i) NRG as of and for the year ended December 31, 2004 and as of and for the nine months ended September 30, 2005, (ii) Texas Genco as of and for the year ended December 31, 2004 and as of and for the nine months ended September 30, 2005, and (iii) the combined company on a pro forma basis for the year ended December 31, 2004 and as of and for the nine months ended September 30, 2005, giving effect to (a) the reclassification of Audrain as a discontinued operation; see Recent Developments ; (b) the inclusion of the results pursuant to the ROFR (as described below); (c) the refinancing of NRG s old debt structure; (d) the remaining Financing Transactions and subsequent Acquisition; and (e) the acquisition of the remaining 50% ownership interest in WCP Holdings and the sale of our 50% ownership interest in Rocky Road; see Recent Developments.

The summary historical consolidated financial information of NRG as of and for the year ended December 31, 2004 were derived from the audited consolidated financial information contained in the audited consolidated financial statements of NRG incorporated by reference in this prospectus supplement. The summary unaudited historical consolidated financial information for NRG as of and for the nine months ended September 30, 2005 (i) were derived from NRG s unaudited consolidated financial statements which are incorporated by reference into this prospectus supplement, (ii) have been prepared on a similar basis to that used in the preparation of the audited financial statements of NRG and (iii) in the opinion of NRG s management, include all adjustments necessary for a fair statement of the results for the unaudited interim period. The results for periods for less than a full year are not necessarily indicative of the results to be expected for any interim period.

The summary historical consolidated financial information of Texas Genco as of and for the year ended December 31, 2004 were derived from the audited consolidated financial information contained in the audited consolidated financial statements of Texas Genco incorporated by reference into this prospectus supplement. The summary unaudited historical consolidated financial information for Texas Genco as of and for the nine months ended September 30, 2005 (i) were derived from Texas Genco s unaudited financial statements which are incorporated by reference into this prospectus supplement, (ii) have been prepared on a similar basis to that used in the preparation of the audited financial statements of Texas Genco, and (iii) in the opinion of Texas Genco s management, include all adjustments necessary for a fair statement of the results for the unaudited interim period. The results for periods for less than a full year are not necessarily indicative of the results to be expected for any interim period.

The historical financial information for WCP as of and for the year ended December 31, 2004 were derived from the audited financial statements of WCP as of and for the year ended December 31, 2004 contained as Exhibit 99.1 in NRG s Form 10-K filed on March 30, 2005. The unaudited historical consolidated financial information as of and for the nine months ended September 30, 2005 (i) have been derived from WCP s unaudited condensed consolidated financial statements that are included as Exhibit 99.06 to the current report on Form 8-K/4 filed on January 5, 2006 and incorporated in this prospectus supplement by reference, (ii) have been prepared on a similar basis to that used in the preparation of the audited financial statements, and (iii) in the opinion of WCP s management, include all adjustments necessary for a fair statement of the results for the unaudited interim period.

The unaudited pro forma combined income statement data and other financial data for the combined company for the year ended December 31, 2004 and for the nine months ended September 30, 2005 give effect to (a) the reclassification of Audrain as a discontinued operation; (b) the inclusion of the results pursuant to the ROFR; (c) the refinancing of NRG s old debt structure; (d) the remaining Financing Transactions and subsequent Acquisition; and (e) the acquisition of the remaining 50% ownership interest in WCP Holdings and the sale of our 50% ownership interest in Rocky Road, as if they had occurred on January 1, 2004. The unaudited pro forma combined balance sheet data as of September 30, 2005 gives effect to (a) the sale of Audrain as of September 30, 2005; (b) the refinancing of NRG s old debt structure; (c) the remaining Financing Transactions and subsequent Acquisition; and (d) the acquisition of the remaining 50% ownership interest in WCP Holdings and the sale of our 50% ownership interest in Rocky Road, as if they had occurred on September 30, 2005. The adjustments reflected in the unaudited pro forma financial data are based on available information and assumptions management believes are reasonable. However, due to the lack of asset appraisals and a future closing date, it is difficult to estimate a pro forma allocation of purchase price for the Acquisition. For purposes of these pro forma statements we have assumed that the consideration paid in excess of the historical book value of net assets acquired is related to the step-up in fair value of Texas Genco s emission credit inventory, a step-up in the value of Texas Genco s fixed assets, and an increase in liabilities for assumed out-of-market contracts. Once the Acquisition is closed, the excess of the estimated purchase price may differ considerably from these assumptions based on the results of appraisals and the finalization of the purchase price allocation as a result of closing and other analyses, which NRG is obtaining. The other analyses include actuarial studies of employee benefit plans, income tax effects of the Acquisition, analyses of operations to identify assets for disposition and the evaluation of staffing requirements necessary to meet future business needs. Ultimately, the excess of the purchase price over the fair value of the net tangible and identified intangible assets acquired will be recorded as goodwill.

The unaudited pro forma financial information is for informational purposes only, however, and is based on several assumptions, including our assumptions regarding the Financing Transactions and the Acquisition, that may prove to be inaccurate. The unaudited pro forma consolidated financial data presented below do not purport to represent what the combined company s results of operations would actually have been had the Acquisition and the Financing Transactions in fact occurred on the dates specified above or to project the combined company s results of operations for any future period.

The historical consolidated financial information and the unaudited pro forma combined financial information set forth below should be read in conjunction with (i) the consolidated financial statements of NRG, the related notes thereto and Management s Discussion and Analysis of Financial Condition and Results of Operations included in NRG s annual report for the year ended December 31, 2004 as amended by the current report on Form 8-K filed on December 20, 2005, and quarterly report on Form 10-Q for the nine months ended September 30, 2005, each as incorporated in this prospectus supplement by reference, (ii) the consolidated financial statements of Texas Genco and Texas Genco Holdings, Inc., the related notes thereto and Management s Discussion and Analysis of Financial Condition and Results of Operations for the year ended December 31, 2004 and for the nine months ended September 30, 2005, each as incorporated in this prospectus supplement by reference to NRG s current report on Form 8-K filed on December 21, 2005, (iii) the financial statements of WCP, the related notes thereto included in NRG s annual report on Form 10-K as Exhibit 99.1 as of and for the year ended December 31, 2004 and the financial statements as of and for the nine months ended September 30, 2005 as found in Exhibit 99.06 to the current report on Form 8-K/A filed on January 5, 2006 and (iv) Selected Consolidated Financial Information of NRG, Selected Consolidated Financial Information of Texas Genco, Risk Factors Risks Related to the Acquisition Because the historical and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement 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, Texas Genco and your investment decision, and Risk Factors Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business elsewhere in this prospectus supplement. In addition, no assurance can be given that the Acquisition will be consummated in accordance with the anticipated timing or at all. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay.

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	NRG Energy, Inc.(1)	Texas Genco LLC	NRG Energy, Inc.(1)	Texas Genco LLC	Pro Forma Combined Company(1)(2)	
	For the Year Ended December 31, 2004	For the Period from July 19, 2004 through December 31, 2004	For the Nine Months Ended September 30, 2005	For the Nine Months Ended September 30, 2005	For the Year Ended December 31, 2004	For the Nine Months Ended September 30, 2005
			(unaudited)	(unaudited)	(unaudited)	(unaudited)
	($ in thousands, except per share data)					
Income Statement Data:						
Total operating revenues	$ 2,347,882	$ 95,847	$ 1,942,828	$ 1,999,827	$ 5,394,910	$ 5,180,190
Total operating costs and expenses	1,955,887	82,105	1,861,569	1,502,170	4,559,583	3,820,967
Income/(loss) from continuing operations	159,144	(20,133)	6,991	345,928	186,710	620,145
Income/(loss) on discontinued operations, net of income taxes	26,473		12,612		NA	NA
Net income/(loss)	185,617	(20,133)	19,603	345,928	NA	NA
Per Share Data:						
Basic earnings per share	$ 1.86	$ (0.13)(2)	$ 0.07	$ 2.05	$ 1.01	$ 4.11
Diluted earnings per share	1.85	(0.13)(2)	0.07	1.98	1.01	3.78
Other Financial Data:						
Capital expenditures	$ (114,360)	$ (5,744)	$ (45,518)	(73,781)	(120,104)	(119,299)
Cash flows from operating activities	643,993	36,023	(113,802)	408,821	NA	NA
Ratio of earnings to combined fixed charges and preference dividends	1.82x	0.4x	1.04x	3.70x	1.28x	3.02x
Balance Sheet Data (at period						

end):

Cash and cash equivalents	$ 1,103,678	85,939	$ 504,336	222,393	NA	163,065
Restricted cash	109,633		91,508		NA	91,508
Total Assets	7,830,283	4,587,566	7,795,367	6,098,723	NA	20,831,886
Total long-term debt including current maturities	3,723,854	2,280,105	3,042,398	2,742,910	NA	8,009,504
Stockholders equity/(deficit)	2,692,164	771,516	2,019,168	773,112	NA	4,966,403

(1) NRG s results and our pro forma results include the following items that have had a significant impact on operations during the periods indicated below:

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	NRG Energy, Inc.		Pro Forma Combined Company	
	For the Year Ended December 31, 2004	For the Nine Months Ended September 30, 2005	For the Year Ended December 31, 2004	For the Nine Months Ended September 30, 2005
		(unaudited)	(unaudited)	(unaudited)
	($ in thousands)			
(Income)/loss on discontinued operations, net of income taxes	$ 26,473	$ 12,612	(a)	(a)
Corporate relocation charges	16,167	5,651	16,167	5,651
Reorganization items	(13,390)		(13,390)	
Restructuring and impairment charges	44,661	6,223	69,009	6,223
Gain on sale of assets			(689)	(28,358)
Write downs, gains and (losses) on sales of equity method investments	(16,270)	15,894	(16,270)	15,894
FERC authorized settlement	(38,357)		(38,357)	
Write down of Note Receivable	4,572		4,572	

(a) Our pro forma combined company reflects items from continuing operations only.

(2) On May 19, 2005, pursuant to the exercise of a right of first refusal, or the ROFR, by Texas Genco, subsequent to a third party offer to American Electric Power, or AEP, in early 2004, Texas Genco acquired from AEP an additional 13.2% undivided interest in South Texas Project Electric Generating Station, or STP. As a result, Texas Genco currently owns a 44.0% undivided interest in STP. For pro forma purposes, NRG has accounted for the ROFR as a business acquisition and included the ROFR in its pro forma adjustments to the statements of operation. NRG has also accounted for the sale of Audrain, the acquisition of WCP and the sale of Rocky Road for purposes of these pro forma financial statements.

(3) For the period from July 19, 2004 through December 31, 2004.

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RISK FACTORS

Investing in the mandatory convertible preferred stock involves a high degree of risk. The risks below are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our business operations. The following risks could affect our business, financial condition or results of operations. In such a case, you may lose all or part of your original investment. You should carefully consider the risks described below as well as other information and data set forth in this prospectus supplement, the accompanying prospectus and the documents incorporated by reference herein and therein before making an investment decision with respect to the mandatory convertible preferred stock.

Risks Related to the Operation of our Business

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 combined company s domestic revenues is derived from baseload power plants that are fueled by coal or nuclear fuel. In many of the competitive markets where NRG and Texas Genco 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. This tends to increase the market clearing price for power. The current pricing and cost environment allows NRG s and Texas Genco s baseload coal and nuclear fuel 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 NRG and Texas Genco use. This could significantly reduce the operating margins of NRG s and Texas Genco s baseload generation assets and materially and adversely impact NRG s and Texas Genco s 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, or RTOs, 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

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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;
- regulations and actions of the ISOs or RTOs; and
- federal and state power market and environmental regulation and legislation.

These factors have caused NRG s and Texas Genco s 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 an increase in fuel prices or disruption of our fuel supplies.

We rely on coal, nuclear fuel derived from uranium, 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 combined 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;

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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 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.

Texas Genco procures approximately 70% of the fuel for its Limestone facility from a lignite mine adjacent to the plant, pursuant to a contract that expires in 2015. The contract has been the subject of past litigation over pricing and other matters, and requires the parties periodically to renegotiate both the price and volume of lignite provided. If we are unable to renegotiate the terms of the agreement, if the counterparty fails to perform, or if the mine is unable to yield sufficient quantities of lignite, we could experience a disruption of supply, which could result in a curtailment or shutdown of the Limestone plant, or could require us to acquire the fuel at higher spot market prices.

The owners (including Texas Genco) of STP satisfy fuel supply requirements for STP by acquiring uranium concentrates and contracting to convert uranium concentrates into uranium hexafluoride, enrich uranium hexafluoride and fabricate nuclear fuel assemblies. These contracts have varying expiration dates, and most are short to medium term. A disruption in uranium supplies, or in conversion, enrichment or fabrication services, could adversely affect operations at STP or increase the fuel costs associated with 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.

From time to time 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.

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.

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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.

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. On a pro forma basis, approximately 23% of the pro forma combined company s total assets will be goodwill and other intangibles, of which approximately $2.4 billion will be 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.

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 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

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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. See Business Competition.

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.

Construction, 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

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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.

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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 ERCOT, California ISO, New York ISO and New England ISO markets, the combined 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 not be successful.

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 and RTOs. The ISOs and RTOs 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.

Similarly, the Texas Genco subsidiaries are registered as power generation companies with the Public Utility Commission of Texas, or PUCT. PUCT has jurisdiction with respect to the mitigation of undue market power and has authority to remedy market power abuses in the ERCOT market, both directly and, indirectly,

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through oversight of ERCOT. PUCT has proposed a significant change in the rules governing the ERCOT market. Specifically the PUCT adopted a rule directing the ERCOT ISO to develop and implement a wholesale market that, among other things, replaces the existing zonal market design with a nodal market design based on locational marginal prices for power. The market redesign project is expected to take effect in 2009. We expect that implementation of any new market design will require modification to our procedures and systems. 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.

Texas Genco s ownership interest in a nuclear power facility subjects it 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 Texas Genco owns indirectly 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. Texas Genco s 44.0% share of the output of STP represents approximately 1,101 MW of generation capacity, which is approximately 10% of the total gross generation capacity owned by Texas Genco.

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, Texas Genco may incur additional costs to the extent it is obligated to provide power from more expensive alternative sources either Texas Genco s own plants, third party generators or the ERCOT to cover Texas Genco s then existing forward sale obligations. Such shutdown or modification could also lead to substantial costs related to the storage and disposal of radioactive materials and spent nuclear fuel.

Texas Genco 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.

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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.

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. See Business Environmental Matters U.S. Federal Environmental Initiatives Air. 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. See Business Environmental Matters Regional U.S. Environmental Regulatory Initiatives.

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. See Business Environmental Matters Domestic Site Remediation Matters.

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, especially with respect to STP, 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

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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 September 30, 2005, after giving pro forma effect to the Acquisition, approximately 46.8% of the combined company s employees at its U.S. generation plants would have been covered by collective bargaining agreements, and 774 employees of the combined company s plants in Texas are covered by a single collective bargaining agreement that expires in September 2006. 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.

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, microturbines, 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.

Texas Genco s plants are the subject of a number of lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos while working at sites along the Texas Gulf Coast, and NRG is also subject to asbestos-related claims with respect to certain of its facilities.

Many of Texas Genco s 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 Texas Genco s plants, some of the claimants have worked at locations owned by Texas Genco. While Texas Genco has been dismissed from many of these lawsuits without having to make any payment to claimants, Texas Genco has incurred and expects to continue to incur settlement costs associated with these claims. NRG is 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, our liability may be substantial. Moreover, 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 impact our results of operations, financial condition and cash flows.

Our high 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, make it more difficult for us to satisfy our obligations with respect to our indebtedness and limit our ability to react to changes in the economy or our industry.

Our substantial debt could have important consequences for you, 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 senior secured credit facilities, are, and under our new senior secured credit facility will be, at variable rates of interest;

- 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 indenture for the senior notes contains, and our new credit facility will contain, financial and other restrictive covenants that will 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;

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- 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.

Risks Related to the Acquisition

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

The success of the Acquisition will depend largely on NRG s ability to consolidate and effectively integrate Texas Genco s 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.

Texas Genco s power generation assets operate in the ERCOT market, a market in which NRG does not currently operate. Accordingly, we are dependent upon Texas Genco s existing managers and employees to manage those assets, and the loss of key Texas Genco 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 and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement 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, Texas Genco and your investment decision.

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 statements are not comparable to its current financial statements.

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. Preparing the pro forma financial information contained in this prospectus supplement involved making several assumptions, such as the makeup of our capital structure after the consummation of the Financing Transactions. These assumptions may prove inaccurate. Therefore, the historical financial statements and pro forma financial statements incorporated by reference or presented in this prospectus supplement 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.

As a result, the historical and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement is of limited relevance to an investor in this offering. See Selected Consolidated Financial Information of NRG and Selected Consolidated Financial Information of Texas Genco. See also Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business.

Risks Related to the Offering

There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay.

Although NRG expects to close the Acquisition in or about the first week of February 2006, there can be no assurance that the Acquisition will be completed in accordance with the anticipated timing or at all. In order to consummate the Acquisition, NRG and Texas Genco must obtain certain regulatory and other approvals and consents in a timely manner. If these approvals or consents are not received, or they are not received on terms that satisfy the conditions set forth in the Acquisition Agreement, then NRG and/or Texas Genco will not be obligated to complete the Acquisition. Also, NRG and/or Texas Genco may not receive these approvals or consents by the first week of February 2006, the current anticipated timing for closing the Acquisition. The Acquisition Agreement also contains customary and other closing conditions, which may not be satisfied or waived. In addition, under circumstances specified in the Acquisition Agreement, NRG or Texas Genco may terminate the Acquisition Agreement.

The closing of this offering is not conditioned on the consummation of the Acquisition. Therefore, upon the closing of this offering, you will become a holder of NRG s mandatory convertible preferred stock irrespective of whether the Acquisition is consummated or delayed. If the Acquisition is not completed, NRG s common stock, and therefore the mandatory convertible preferred stock that you have purchased in this offering, will not reflect any interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay. If this offering is consummated and the Acquisition does not occur, any expected earnings per share of our common stock will be significantly reduced. Also, the price of NRG s common stock, and therefore of the mandatory convertible preferred stock, may decline to the extent that the current market price of NRG s common stock reflects a market assumption that the Acquisition will be consummated and that NRG will realize certain anticipated benefits of the Acquisition. See also below The price of our common stock, and therefore the price of our mandatory convertible preferred stock, may fluctuate significantly, which may make it difficult for you to resell the mandatory convertible preferred stock, or common stock issuable upon conversion of the mandatory convertible preferred stock, when you want or at prices you find attractive. In addition, NRG s business may be harmed to the extent that customers, suppliers and others believe that NRG cannot effectively compete in the marketplace without Texas Genco, or otherwise remain uncertain about NRG. NRG will be required to pay significant costs incurred in connection with the Acquisition, including legal, accounting, financial advisory and other costs, whether or not the Acquisition is completed. The occurrence of any of these events individually or in combination could have a material adverse effect on NRG s business, financial condition and results of operations.

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The price of our common stock, and therefore the price of our mandatory convertible preferred stock, may fluctuate significantly, which may make it difficult for you to resell the mandatory convertible preferred stock, or common stock issuable upon conversion of the mandatory convertible preferred stock, when you want or at prices you find attractive.

Our common stock price can fluctuate as a result of a variety of factors, many of which are beyond our control. These factors include:

- our ability to consummate the Acquisition in accordance with the anticipated timing or at all;
- new laws or regulations or new interpretations of existing laws or regulations applicable to our business;
- changes in accounting standards, policies, guidance, interpretations or principles;
- our inability to raise additional capital;
- sales of common stock by us or members of our management team;
- quarterly variations in our operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;
- developments generally affecting our industry;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- changes in our dividend policy;
- future sales of our equity or equity-linked securities; and
- general domestic and international economic conditions.

In addition, the stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock and of the mandatory convertible preferred stock.

If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business.

The offering of the mandatory convertible preferred stock forms part of a larger financing plan for the Acquisition described elsewhere in this prospectus supplement. See The Acquisition The Financing Transactions. Concurrently with this offering, NRG intends to conduct offerings of its common stock and New Senior Notes. In addition, NRG intends to enter into a new senior secured credit facility at or prior to the Acquisition that will replace its existing senior secured credit facility. NRG intends to use initial borrowings under its new senior secured credit facility, together with the net proceeds from this offering and the offerings of common stock and New Senior Notes, to finance the Acquisition and to repay certain of its and Texas Genco s outstanding indebtedness. See Use of Proceeds. NRG s obligations under the Acquisition Agreement are not conditioned upon the consummation of any or all of the Financing Transactions. NRG has entered into the commitment letter with the bridge lenders pursuant to which the bridge lenders have committed to fund NRG s new senior secured credit facility and to provide, subject to certain conditions, the additional financing required for the Acquisition through a $5.1 billion bridge loan facility in the event that sufficient funds are not raised from this offering, the common stock offering and/or the New Senior Notes offering. See Description of Certain Indebtedness Bridge Loan Facility.

In the event that NRG is unable to raise sufficient proceeds through the consummation of the New Senior Notes offering and/or the common stock offering, NRG may draw down on the bridge loan facility, in whole or in part, in order to finance the Acquisition. No assurances can be given that the terms of the bridge loan facility on the draw down date would not vary from the existing terms of such facility on the date of this prospectus supplement. See Description of Certain Indebtedness Bridge Loan Facility. In the event of such draw down, we would be significantly more highly leveraged, which means we will have a larger amount of indebtedness in relation to our equity (deficit). Our interest expense would significantly increase and require us to dedicate a substantial portion of our cash flow from operations to payments in respect of our outstanding indebtedness, thereby reducing the availability of our cash flow to fund working capital, including collateral postings, capital expenditures and other general corporate expenditures. Our substantial indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under the notes.

In the event that NRG does not consummate the common stock offering and the New Senior Notes offering as currently contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis. This could further exacerbate the risks associated with our substantial leverage. There can be no assurance as to the terms on which NRG would issue these senior secured debt securities or borrow funds. We are unable to predict the interest rate payable on any such debt or give any assurance that the terms would not restrict our financial flexibility or limit our ability to operate our business.

Our ability to pay dividends may be limited.

The terms of our existing senior secured credit facility and the indenture for the Second Priority Notes restrict, and we expect the terms of our new senior credit facility and the indenture governing the New Senior Notes to restrict, our ability to pay dividends to the holders of our stock, including our mandatory convertible preferred stock. If we issue the Cumulative Redeemable Preferred Stock to the Sellers pursuant to the Acquisition Agreement, we will be prohibited from paying dividends on our common stock so long as any shares of Cumulative Redeemable Preferred Stock are outstanding. In the future, we may agree to further restrictions on our ability to pay dividends. In addition, to maintain our credit ratings, we may be limited in our ability to pay dividends so that we can maintain an appropriate level of debt. Our future dividend policy depends on earnings, financial condition, liquidity, capital requirements and other factors. There is no guarantee that we will pay dividends on shares of our common stock.

Purchasers of mandatory convertible preferred stock who convert their shares into shares of our common stock will incur immediate net tangible book value dilution.

Persons purchasing our mandatory convertible preferred stock who convert their shares into shares of our common stock will incur immediate net tangible book value dilution.

In addition, the terms of our mandatory convertible preferred stock do not restrict our ability to offer a new series of preferred stock that is on parity with the mandatory convertible preferred stock in the future, or to engage in other transactions that could dilute our mandatory convertible preferred stock.

A holder of our mandatory convertible preferred stock may realize some or all of a decline in the market value of shares of our common stock.

The market value of shares of our common stock on March 16, 2009 may be less than $48.75 per share, which we call the initial price. If that market value is less than the initial price, then holders of our mandatory convertible preferred stock will receive shares of our common stock on March 16, 2009 with a market value per share that is less than the initial price. Accordingly, a holder of mandatory convertible preferred stock

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assumes the entire risk that the market value of shares of our common stock may decline. Any decline in the market value of shares of our common stock may be substantial.

Shares of our common stock eligible for future issuance or sale may cause our common share price to decline, which may negatively impact your investment.

Issuances or sales of substantial numbers of additional shares of our common stock, including in connection with future acquisitions, if any, or the perception that such issuances or sales could occur, may cause prevailing market prices for shares of our common stock to decline and may adversely affect our ability to raise additional capital in the financial markets at a time and price favorable to us. As of the date of this prospectus supplement, our amended and restated certificate of incorporation provides that we have authority to issue up to 500,000,000 shares of our common stock. As of January 3, 2006, 100,048,676 shares of our common stock were issued, 80,701,888 shares of our common stock were outstanding and 19,346,788 shares of our common stock were issued and held in treasury. Also as of such date, there were 4,000,000 shares of our common stock reserved for issuance under stock incentive plans or pursuant to individual option grants or stock awards. As of January 3, 2006, 13,075,986 shares of common stock were reserved for future issuance upon conversion of NRG s 4% Convertible Perpetual Preferred Stock and 8,670,000 shares of our common stock were reserved for future issuance upon conversion of NRG s 3.625% Convertible Perpetual Preferred Stock. In addition, subject to any anti-dilution adjustments, an additional 8,271,200 to 10,256,400 shares of our common stock will be issuable upon conversion of the shares of mandatory convertible preferred stock (and an additional 1,240,680 to 1,538,460 shares of our common stock if the underwriters exercise their option to purchase additional shares of mandatory convertible preferred stock in full). We will reserve for issuance the maximum number of shares of our common stock issuable upon conversion of the mandatory convertible preferred stock. See Description of Mandatory Convertible Preferred Stock.

In connection with the Acquisition, we are issuing to the Sellers shares of our common stock valued at approximately 1.6 billion on a pro forma basis. The shares of common stock issued to the Sellers are subject to a 180 day lock-up period following the closing date of the Acquisition. If the restrictions under the lock-up agreements are waived or terminated, or upon expiration of the lock-up period, such shares held by the Sellers will be available for sale into the market at that time, subject only to applicable securities laws, rules and regulations. These sales or a perception that these sales may occur could reduce the market price for our common stock.

Our issuance of additional series of shares of our preferred stock could adversely affect holders of shares of our common stock and, as a result, holders of the mandatory convertible preferred stock.

After giving effect to this offering, our board of directors is authorized to issue additional classes or series of shares of our preferred stock without any action on the part of our shareholders. Our board of directors also has the power, without shareholder approval, to set the terms of any such classes or series of shares of our preferred stock that may be issued, including voting rights, dividend rights, conversion features, preferences over shares of our common stock with respect to dividends or if we liquidate, dissolve or wind up our business and other terms. If we issue shares of our preferred stock in the future that have preference over shares of our common stock with respect to the payment of dividends or upon our liquidation, dissolution or winding up, or if we issue shares of our preferred stock with voting rights that dilute the voting power of shares of our common stock, the rights of holders of shares of our common stock or the market price of shares of our common stock, and as a result of our mandatory convertible preferred stock, could be adversely affected.

The opportunity for equity appreciation provided by an investment in the shares of our mandatory convertible preferred stock is less than that provided by a direct investment in shares of our common stock.

The number of shares of our common stock that are issuable upon mandatory conversion on the conversion date of our mandatory convertible preferred stock will decrease if the applicable market value increases to above $48.75. Therefore, the opportunity for equity appreciation provided by an investment in our mandatory convertible preferred stock is less than that provided by a direct investment in shares of our

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common stock. Assuming the initial price accurately reflects fair market value, the market value of shares of our common stock on March 16, 2009 must exceed the threshold appreciation price of $60.45 before a holder of our mandatory convertible preferred stock will realize any equity appreciation.

Holders of our mandatory convertible preferred stock will have no rights as holders of shares of our common stock until they acquire shares of our common stock.

Until you acquire shares of our common stock upon conversion, you will have no rights with respect to shares of our common stock, including voting rights (except as described under Description of Mandatory Convertible Preferred Stock Voting Rights and as required by applicable state law), rights to respond to tender offers and rights to receive any dividends or other distributions on shares of our common stock. Upon conversion, you will be entitled to exercise the rights of a holder of shares of our common stock only as to matters for which the record date occurs on or after the conversion date.

Our mandatory convertible preferred stock has never been publicly traded and may never be publicly traded.

Prior to this offering, there has been no public market for our mandatory convertible preferred stock. We have applied to list our mandatory convertible preferred stock on the New York Stock Exchange under the symbol NRGPra. There can be no assurance, however, that an active trading market will develop, or if developed, that an active trading market will be maintained. Also, the underwriters have advised us that they intend to facilitate secondary market trading by making a market in our mandatory convertible preferred stock. However, the underwriters are not obligated to make a market in our mandatory convertible preferred stock and may discontinue market making activities at any time.

Our mandatory convertible preferred stock will rank junior to all of our and our subsidiaries liabilities in the event of a bankruptcy, liquidation or winding up of our assets.

In the event of bankruptcy, liquidation or winding up, our assets will be available to pay obligations on our mandatory convertible preferred stock only after all of our liabilities have been paid. In addition, our mandatory convertible preferred stock will effectively rank junior to all existing and future liabilities of our subsidiaries and the capital stock of our subsidiaries held by third parties. The rights of holders of our mandatory convertible preferred stock to participate in the assets of our subsidiaries upon any liquidation or reorganization of any subsidiary will rank junior to the prior claims of that subsidiary s creditors and equity holders. In the event of bankruptcy, liquidation or winding up, there may not be sufficient assets remaining, after paying our and our subsidiaries liabilities, to pay amounts due on any or all of our mandatory convertible preferred stock then outstanding.

The mandatory convertible preferred stock provides limited settlement rate adjustments.

The number of shares of our common stock that you are entitled to receive on the mandatory conversion date, or as a result of early conversion of our mandatory convertible preferred stock, is subject to adjustment for certain events arising from stock splits and combinations, stock dividends, cash dividends and certain other actions by us or a third party that modify our capital structure and in connection with certain acquisitions of us, as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount and Description of Mandatory Convertible Preferred Stock Anti-Dilution Adjustments. We will not adjust the conversion rate for other events, including offerings of shares of our common stock for cash by us or in connection with acquisitions. There can be no assurance that an event that adversely affects the value of the mandatory convertible preferred stock, but does not result in an adjustment to the conversion rate, will not occur. Further, the terms of our mandatory convertible preferred stock do not restrict us from issuing additional shares of our common stock during the term of the mandatory convertible preferred stock and we have no obligation to consider your interests for any reason when doing so. If we issue additional shares of our common stock, it may materially and adversely affect the price of shares of our common stock and such other events may adversely affect the trading price of the mandatory convertible preferred stock.

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We may not have sufficient earnings and profits in order for distributions on the preferred stock to be treated as dividends for U.S. federal income tax purposes.

The dividends paid by us may exceed our current and accumulated earnings and profits, as calculated for U.S. federal income tax purposes. This will result in the amount of the dividends that exceeds such earnings and profits being treated first as a return of capital to the extent of the holder s adjusted tax basis in the preferred stock, and the excess as capital gain. Such treatment will generally be unfavorable for corporate holders and may also be unfavorable to certain other holders.

You may be required to recognize income upon an adjustment of the conversion rate.

In general, any adjustment to the conversion rate that increases the interest of the holders who hold mandatory convertible preferred shares in our assets or earnings and profits will result in a constructive dividend distribution to such holders, and such holders will be subject to tax on this constructive dividend distribution to the extent of our earnings and profits even though no money will have actually been distributed. An exception to this rule provides that changes in the conversion rate made solely to avoid dilution of the interests of holders who hold mandatory convertible preferred shares will not result in a constructive dividend, but this exception specifically does not cover conversion rate adjustments that are made to compensate the holders of our mandatory convertible preferred shares for taxable cash or property distributions to other shareholders. As a result, some of the possible circumstances that could result in an adjustment to the conversion rate with respect to our mandatory convertible preferred shares are not covered by this exception. For example, an increase in the conversion rate in the event of distributions of cash, indebtedness or assets by us will generally result in deemed dividend treatment to holders of our mandatory convertible preferred shares to the extent of our applicable earnings and profits.

The conversion rate and payment you may receive in respect of shares of mandatory convertible preferred stock converted in connection with certain cash acquisitions of us may not adequately compensate you for the lost option time value of your mandatory convertible preferred stock as a result of such change.

If certain cash acquisitions of us occur on or prior to March 16, 2009, under certain circumstances, we will (1) permit conversion of our mandatory convertible preferred stock during the period beginning on the date that is 15 days prior to the anticipated effective date of the applicable cash acquisition and ending on the date that is 15 days after the actual effective date and (2) pay converting holders an amount equal to the sum of any accumulated and unpaid dividends on shares of our mandatory convertible preferred stock that are converted plus the present value of all remaining dividend payments on such shares through and including March 16, 2009, as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount. The applicable conversion rate will be determined based on the date on which the transaction becomes effective and the price paid per share of our common stock in such transaction as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount. While the conversion rate adjustment and the additional payment amount are designed to compensate you for the lost option time value of your mandatory convertible preferred stock and lost dividends resulting from your decision to convert early as a result of such transaction, the amount of the make-whole premium is only an approximation of such lost value and may not adequately compensate you for such loss.

Our corporate documents, Delaware law and the terms of the mandatory convertible preferred stock contain provisions that could discourage, delay or prevent a change in control of our company even if some stockholders might consider such a development favorable, which may adversely affect the price of our mandatory convertible preferred stock and common stock.

Provisions in our amended and restated certificate of incorporation and amended and restated by-laws may discourage, delay or prevent a merger or acquisition involving us that our stockholders may consider favorable. For example, our amended and restated certificate of incorporation authorizes our board of directors to issue shares of preferred stock to which special rights are attached, including voting and dividend rights. With these rights, preferred stockholders could make it more difficult for a third party to acquire us. In

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addition, our amended and restated certificate of incorporation provides for a staggered board of directors, whereby directors serve for three-year terms, with approximately one third of the directors coming up for reelection each year. Having a staggered board of directors would make it more difficult for a third party to obtain control of our board of directors through a proxy contest, which may be a necessary step in an acquisition of us that is not favored by our board of directors.

We are also subject to the anti-takeover provisions of Section 203 of the Delaware General Corporation Law. Under these provisions, if anyone becomes an interested stockholder, we may not enter into a business combination with that person for three years without special approval, which could discourage a third party from making a takeover offer and could delay or prevent a change of control. For purposes of Section 203, interested stockholder means, generally, someone owning 15% or more of our outstanding voting stock or an affiliate of ours that owned 15% or more of our outstanding voting stock during the past three years, subject to certain exceptions as described in Section 203.

Under NRG s existing senior secured credit facility, and the new senior secured credit facility which we expect will be in effect after closing of the Acquisition, a change of control is an event of default. Upon the occurrence of a change in control, the holders of the New Senior Notes will have the right, subject to certain conditions, to require us to repurchase their notes at a price equal to 101% of their principal amount plus accrued and unpaid interest and liquidated damages, if any, to the date of repurchase.

If certain cash acquisitions of us occur on or prior to March 16, 2009, under certain circumstances, we will (1) permit conversion of our mandatory convertible preferred stock during the period beginning on the date that is 15 days prior to the anticipated effective date of the applicable cash acquisition and ending on the date that is 15 days after the actual effective date and (2) pay converting holders an amount equal to the sum of any accumulated and unpaid dividends on shares of our mandatory convertible preferred stock that are converted plus the present value of all remaining dividend payments on such shares through and including March 16, 2009, as described under Description of Mandatory Convertible Preferred Stock Conversion Upon Cash Acquisition; Cash Acquisition Dividend Make-Whole Amount. Such provisions may make it more costly for a potential acquirer to pursue an acquisition of us, including an acquisition that holders of our common stock and holders of our mandatory convertible preferred stock would find desirable.

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THE ACQUISITION

The Acquisition

Overview

On September 30, 2005, NRG entered into the Acquisition Agreement with Texas Genco and the Sellers. Pursuant to the Acquisition Agreement, NRG agreed to purchase all of the outstanding equity interests in Texas Genco for a total pro forma purchase price of approximately $6.121 billion that includes the assumption of approximately $2.7 billion of indebtedness. The purchase price is subject to adjustment, and includes an equity component valued at up to $2.0 billion based on a price per share of $45.37 of NRG s common stock issued to the Sellers, and an average price per share of $40.73 for the Other Consideration to the Sellers. As a result of the Acquisition, Texas Genco will become a wholly-owned subsidiary of NRG.

The closing of this offering is not conditioned on the consummation of the Acquisition. While we expect that the Acquisition will be consummated in or about the first week of February 2006, no assurance can be given that the Acquisition will be completed in accordance with the anticipated timing or at all. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay.

Certain Terms and Conditions of the Acquisition Agreement

Of the approximately $6.121 billion payable to the Sellers upon consummation of the Acquisition, NRG will pay $4.399 billion in cash, subject to adjustment, and issue a minimum of 35,406,320 shares of NRG s common stock. The remaining consideration is to be comprised of an additional 9,038,125 shares of common stock, or at NRG s election, the equivalent in the form of common stock, additional cash or shares of a new series of NRG s Cumulative Redeemable Preferred Stock, or any combination of the foregoing. If issued, the aggregate liquidation preference of the Cumulative Preferred Stock will be determined by reference to the average price of NRG s common stock over a 20 trading day period prior to the closing of the Acquisition, which on a pro forma basis is $40.73. NRG has elected to pay this amount in cash. The purchase price payable by NRG is subject to adjustment based on the level of Texas Genco s working capital, the amount of Texas Genco s indebtedness and the amount of Texas Genco s cash and cash equivalents on hand, all as of the closing date.

The Acquisition Agreement contains customary terms and conditions, including representations and warranties of NRG, Texas Genco and the Sellers and covenants of NRG and Texas Genco with respect to the conduct of their businesses prior to the closing of the Acquisition. Pending closing of the Acquisition, Texas Genco and NRG are obligated to conduct their businesses in the ordinary course of business, to preserve their business, assets, properties and relationships, and to refrain from certain activities without prior written consent of the other party, such consent not to be unreasonably withheld or delayed.

The obligations of NRG, on the one hand, and Texas Genco and the Sellers, on the other, to consummate the Acquisition are subject to the satisfaction or waiver of various conditions, including: the other party or parties having performed their agreements, covenants and obligations required by the Acquisition Agreement in all material respects and having delivered certain certificates and other documents, the representations and warranties of the other party or parties being true and correct on the date of the Acquisition Agreement and the closing date (except for inaccuracies that would not, individually or in the aggregate, have a Material Adverse Effect (as defined in the Acquisition Agreement)), no Law or Order (each as defined in the Acquisition Agreement) being in effect on the closing date that would prohibit the consummation of the acquisition or related transactions, no Material Adverse Effect on the other party having occurred since June 30, 2005, the parties having received all consents and approvals of, and made all filings with various governmental authorities necessary to consummate the acquisition and related transactions, including with respect to the NRC and FERC, and any applicable terminations or expirations of waiting periods having

occurred, including with respect to the Hart Scott Rodino Antitrust Improvements Act, or the HSRA. On November 10, 2005, NRG was notified by the Federal Trade Commission s Premerger Notification Office that early termination of the applicable waiting period under the HSRA was granted with respect to the Acquisition. On December 27, 2005, FERC granted approval for the Acquisition. On January 13, 2006, NRG and Texas Genco received approval from the Nuclear Regulatory Commission to transfer indirect ownership of the 44 percent interest in the South Texas Project Electric Generation Station. The Acquisition Agreement does not contain any financing condition.

The Acquisition Agreement may be terminated upon the occurrence of certain events, including at any time before closing by mutual written agreement of NRG and the Seller Representatives (as defined in the Acquisition Agreement). NRG or the Seller Representatives may terminate the Acquisition Agreement if the Acquisition has not been consummated within nine months of the date of the Acquisition Agreement (subject to certain provisions for extension), upon an uncured material breach by the other party or parties of any of the covenants, agreements or representations or warranties in the Acquisition Agreement if such breach would cause a failure of any of the conditions to the obligations of NRG or the Sellers, as the case may be, to consummate the Acquisition, upon an Order by a Governmental Authority (each as defined in the Acquisition Agreement) preventing the consummation of the Acquisition or the related transactions or the failure by a Governmental Authority to issue certain required approvals for the Acquisition or related transactions, which failure becomes final and non-appealable, or if the other party has incurred a Material Adverse Effect (as defined in the Acquisition Agreement) on the other party.

The Financing Transactions

The offering of mandatory convertible preferred stock forms part of a larger financing plan for the Acquisition described elsewhere in this prospectus supplement. Concurrently with this offering, NRG intends to offer, by means of separate prospectus supplements (i) $1.0 billion of its common stock and (ii) $3.6 billion of the New Senior Notes. See Description of Capital Stock Common Stock and Description of Certain Indebtedness New Senior Notes. This offering, the common stock offering and the New Senior Notes offering are expected to be consummated at or prior to the completion of the Acquisition. The closing of this offering will not necessarily be contemporaneous with the closing of the common stock offering and/or the closing of the New Senior Notes offering. The net proceeds of the offering of the New Senior Notes (after payment of underwriting discounts and commissions) will be placed into an escrow account held by the escrow agent until the consummation of the Acquisition.

In addition, NRG intends to enter into a new senior secured credit facility at or prior to the closing of the Acquisition that will replace its existing senior secured credit facility. See Description of Certain Indebtedness New Senior Secured Credit Facility. Concurrently with this offering, NRG is conducting a cash tender offer and consent solicitation with respect to (i) all of its outstanding the Second Priority Notes, and (ii) all of Texas Genco s outstanding Unsecured Senior Notes. The completion of the Acquisition is not conditioned on the completion of the tender offer or receipt of the consents for either the Second Priority Notes or Texas Genco s Unsecured Senior Notes. The completion of the tender offer for the Second Priority Notes and Texas Genco s Unsecured Senior Notes is conditioned on the completion of the Acquisition. However, NRG can waive this condition in the case of the tender offer and consent solicitation for the Second Priority Notes. See Summary Recent Developments Tender Offers and Consent Solicitations.

NRG intends to use initial borrowings under its new senior secured credit facility, together with the net proceeds from this offering, the offerings of common stock and New Senior Notes and cash on hand (i) to finance the Acquisition, (ii) to repurchase NRG s outstanding Second Priority Notes, (iii) to repurchase Texas Genco s outstanding Unsecured Senior Notes, (iv) to repay amounts outstanding under NRG s existing senior secured credit facility and Texas Genco s existing senior secured credit facility, (v) for ongoing credit needs of the combined company, including replacement of existing letters of credit and (vi) to pay related premiums, fees and expenses. In the event that NRG does not consummate the Acquisition, NRG intends to use the net proceeds from this offering for general corporate purposes. See Use of Proceeds.

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The closing of this offering is not contingent on the closing of the common stock offering, the closing of the New Senior Notes offering, the effectiveness of the new senior secured credit facility, the completion of the tender offers and receipt of the consents in connection with the outstanding tender offers for NRG s and Texas Genco s notes or the consummation of the Acquisition. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay. NRG s obligations under the Acquisition Agreement are not conditioned upon the consummation of any or all of the Financing Transactions.

NRG has entered into the commitment letter with the bridge lenders pursuant to which the bridge lenders have committed to fund NRG s new senior secured credit facility and to provide, subject to certain conditions, the additional financing required for the Acquisition through a $5.1 billion bridge loan facility in the event that sufficient funds are not raised from this offering, the common stock offering and/or the New Senior Notes offering. See Description of Certain Indebtedness Bridge Loan Facility. In the event that NRG is unable to raise sufficient proceeds through the consummation of this offering, the common stock offering and/or the New Senior Notes offering, NRG may draw down on the bridge loan facility, in whole or in part, in order to finance the Acquisition. In the event that NRG does not consummate the common stock offering and the New Senior Notes offering as currently contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis.

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USE OF PROCEEDS

We estimate that the net proceeds of this offering, after giving effect to underwriting discounts, commissions and estimated expenses payable by us, will be approximately $484.7 million. We intend to use the net proceeds from this offering and the offerings of common stock and New Senior Notes, together with initial borrowings under our new senior secured credit facility and cash on hand, (i) to finance the Acquisition, (ii) to repurchase NRG s outstanding Second Priority Notes, (iii) to repurchase Texas Genco s outstanding Unsecured Senior Notes, (iv) to repay amounts outstanding under NRG s existing senior secured credit facility and Texas Genco s existing senior secured credit facility, (v) for ongoing credit needs of the combined company, including replacement of existing letters of credit and (vi) to pay related premiums, fees and expenses. In the event that NRG does not consummate the Acquisition, NRG intends to use the net proceeds from this offering for general corporate purposes. The closing of this offering is not conditioned on the consummation of the Acquisition.

NRG has agreed to acquire Texas Genco for a total pro forma purchase price of approximately $6.121 billion, including an equity component valued at approximately $2.0 billion. In addition, NRG will assume approximately $2.7 billion of Texas Genco s debt. Before giving effect to the Acquisition and Financing Transactions, as of September 30, 2005, NRG had (i) $1.08 billion of Second Priority Notes outstanding, which provide for cash interest at 8.0% per annum payable semi-annually and (ii) $876.6 million of outstanding indebtedness under its amended and restated credit facility, which consisted of (a) $446.6 million in term loans outstanding, which term loans provide for interest at a rate of LIBOR (4.02% at September 30, 2005) plus 187.5 basis points payable quarterly and mature on December 24, 2011, (b) $80.0 million in principal amount outstanding under the revolving credit facility, which provides for interest at a rate of LIBOR (3.83% at September 30, 2005) plus 2.5% and matures on December 24, 2007 and (c) $350.0 million outstanding under the funded letter of credit facility, which provide for a participation fee of 1.875%, a deposit fee of 0.10%, and an issuance fee of 0.25% and matures on December 24, 2011. In addition, before giving effect to the Acquisition and Financing Transactions, as of September 30, 2005 (i) Texas Genco had $1.125 billion of Unsecured Senior Notes outstanding, which provide for cash interest at 6.875% per annum payable semiannually and (ii) Texas Genco had $1,614 million in term loans outstanding under its existing senior secured credit facility, which term loans provide for interest at a rate of 5.94% (as of September 30, 2005) payable at least quarterly and mature in December 2011. See The Acquisition and Description of Certain Indebtedness.

Sources and Uses of Funds

The following table sets forth the sources and uses of funds in connection with the Acquisition on a pro forma basis giving effect to the Transactions as if they occurred on September 30, 2005. No assurances can be given that the information in the following table will not change depending on the nature of our financings. See Risk Factors Risks Related to the Acquisition Because the historical and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement 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, Texas Genco and your investment decision and Risk Factors Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business.

Sources[1]	Amount
	(in millions)
Gross proceeds of mandatory preferred stock offering	$ 500
New senior secured term loan facility	3,575
Cash released from canceling existing funded letter of credit facility	350
Gross proceeds of common stock offering	1,016
Common stock consideration to be issued to Sellers	1,606[2]
Gross proceeds of 2014 fixed rate notes offering	1,200
Gross proceeds of 2016 fixed rate notes offering	2,400
NRG s cash on hand	373
Total	$ 11,020

Uses		Amount
		(in millions)
Purchase price less acquisition costs[2]		$ 6,005
Texas Genco s cash on hand to reduce consideration		(222)
Refinancing:		
Repayment of NRG s existing credit facilities	877	
Repayment of Texas Genco s existing credit facilities	1,614	
Total repayment of existing credit facilities		2,491
Repurchase of NRG s Second Priority Notes		1,080
Repurchase of Texas Genco s Unsecured Senior Notes		1,125
Accrued interest for NRG and Texas Genco outstanding debt		52
Estimated underwriting commissions, tender offer premiums, fees and expenses		489
Total		$ 11,020

(1) NRG has entered into the commitment letter with the bridge lenders pursuant to which the bridge lenders have committed to fund NRG s new senior secured credit facility and to provide, subject to certain conditions, the additional financing required for the Acquisition through a $5.1 billion bridge loan facility in the event that this offering, the common stock offering and/or the New Senior Notes offering are not consummated. In the event that NRG is unable to raise sufficient proceeds through the consummation of this offering, the common stock offering and/or the New Senior Notes offering, NRG may draw down on the bridge loan facility, in whole or in part, in order to finance the Acquisition. In the event that NRG does not consummate the common stock offering and the New Senior Notes offering as currently contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis.

(2) The common stock component of the consideration for the Acquisition is based on a fair value of $45.37 per share of NRG s common stock and Other Consideration is valued based on an average common stock price of $40.73, as prescribed by the Acquisition Agreement. This is because the foregoing table is based on a pro forma closing date of the Acquisition of September 30, 2005. To the extent NRG s common stock price for purposes of the equity component, and Texas Genco s cash on hand, is different at closing of the Acquisition, this amount and the purchase price for the Acquisition will be adjusted accordingly.

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CAPITALIZATION

The following table sets forth NRG s consolidated capitalization as of September 30, 2005 on an actual historical basis and on a combined pro forma cumulative as adjusted basis to reflect (i) sale of Audrain; (ii) the refinancing of NRG s old debt structure; (iii) the remaining Financing Transactions and subsequent Acquisition and (iv) the acquisition of the remaining 50% of WCP Holdings and sale of our 50% ownership interest in Rocky Road, as if these transactions were consummated on September 30, 2005. The table below should be read in conjunction with The Acquisition, Use of Proceeds and the consolidated financial statements and the related notes thereto included in or incorporated by reference into this prospectus supplement and the accompanying prospectus. No assurances can be given that the information in the following table will not change depending on the nature of our financings. See Risk Factors Risks Related to the Acquisition Because the historical and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement 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, Texas Genco and your investment decision and Risk Factors Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business elsewhere in this prospectus supplement. In addition, no assurance can be given that the Acquisition will be consummated in accordance with the anticipated timing or at all. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay.

	As of September 30, 2005				
	Historical	**As Adjusted for Audrain**	**Cumulative As Adjusted for Audrain and Refinancing (8)**	**Cumulative As Adjusted for Audrain, Refinancing and Texas Genco Acquisition**	**Cumulative As Adjusted for the Transactions (1)**
Cash and cash equivalents	$ 504.3	$ 519.3	$ 249.2	$ 146.4	$ 163.0
Restricted cash	91.5	91.5	91.5	91.5	91.5
Long-term debt (including revolving line of credit):					
Old Senior Secured Credit Facility:					
	796.6	796.6			

Old Term Loan Facility					
Old Revolving Credit Facility[(2)]	80.0	80.0			
Outstanding Second Priority Notes[(3)]	1,080.4	1,080.4			
Xcel Energy Note[(4)]	9.6	9.6	9.6	9.6	9.6
New Senior Secured Credit Facility			446.6	3,575.0	3,575.0
2016 Fixed Rate Notes			1,080.4	2,400.0	2,400.0

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	As of September 30, 2005				
	Historical	As Adjusted for Audrain	Cumulative As Adjusted for Audrain and Refinancing (8)	Cumulative As Adjusted for Audrain, Refinancing and Texas Genco Acquisition	Cumulative As Adjusted for the Transactions (1)
2014 Fixed Rate Notes				1,200.0	1,200.0
Existing non-guarantor debt[5]	607.2	607.2	607.2	607.2	607.2
Total debt, before capital leases	2,573.8	2,573.8	2,143.8	7,791.8	7,791.8
Capital leases	470.4	230.5	230.5	234.4	234.4
Total debt and capital leases	$ 3,044.2	$ 2,804.3	$ 2,374.3	$ 8,026.2	$ 8,026.2
3.625% Convertible Preferred Stock	246.2	246.2	246.2	246.2	246.2
Mandatory Convertible Preferred Stock[6]				484.6	484.6
Convertible Perpetual Preferred Stock	406.2	406.2	406.2	406.2	406.2
Other stockholders equity [7]	1,613.0	1,628.2	1,538.6	4,100.8	4,075.6
Total capitalization	$ 5,309.6	$ 5,084.9	$ 4,565.3	$ 13,264.0	$ 13,238.8

(1) NRG has entered into the commitment letter with the bridge lenders pursuant to which the bridge lenders have committed to fund NRG s new senior secured credit facility and to provide, subject to certain conditions, the additional financing required for the Acquisition through a $5.1 billion bridge loan facility in the event that this offering, the common stock offering and/or the New Senior Notes offering are not consummated. In the event that NRG is unable to raise sufficient proceeds through the consummation of this offering, the common stock offering and/or the New Senior Notes offering, NRG may draw down on the bridge loan facility, in whole or in part, in order to finance the Acquisition. See Description of Certain Indebtedness Bridge Loan Facility. In the event that NRG does not consummate the common stock offering and the New Senior Notes offering as currently

contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis.

(2) Total borrowing availability under the revolving credit facility portion of NRG s old senior secured credit facility is $150.0 million, of which $80.0 million was drawn at September 30, 2005.

(3) The outstanding balance for the Second Priority Notes has been increased by $14.8 million because the tack-on offering was sold at a premium. The outstanding note balance excludes a decrease of $16.7 million as a result of an unfavorable fair value hedge on an interest rate swap entered into in March 2004. This interest rate swap will remain after the Acquisition and Financing Transactions.

(4) Xcel Energy Note has been reduced by $0.4 million as a result of marking the debt to a market rate of 9% in connection with NRG s Fresh Start reporting on December 5, 2003. The stated interest rate of the note is 3%.

(5) As of September 30, 2005, existing non-guarantor debt has been reduced by $59.0 million as a result of marking the debt to a market rate in connection with NRG s Fresh Start reporting on December 5, 2003. For more information on the various components of NRG s debt, refer to Note 18 to NRG s audited consolidated financial statements as of and for the year ended December 31, 2004 as amended on our Current Report on Form 8-K filed on December 20, 2005 incorporated herein by reference.

(6) The Mandatory Convertible Preferred Stock will be converted on March 16, 2009, and is subject to a 5.75% cumulative annual dividend. The Mandatory Convertible Preferred Stock has a total liquidation preference of $500 million and a conversion rate ranging from 4.14 to 5.13 shares of common stock per share of Mandatory

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Convertible Preferred Stock, depending on the price of NRG s common stock at the time of conversion, and is convertible at the option of the holder at any time.

(7) Pro forma adjustments to Stockholders Equity include the issuance of $1.0 billion of common stock in the concurrent common stock offering, and the issuance of common stock and reissuance of treasury stock to the Sellers valued at $1,606.4 million. These amounts are impacted by a $15.3 million gain on sale of Audrain, a $25.2 million loss from the sale of Rocky Road and closing costs net of tax of $118.9 million.

(8) Refinancing reflects the changes due to the refinancing of NRG s old debt structure.

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PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Pursuant to the consummation of the NRG plan of reorganization, on December 5, 2003, all shares of our old common stock were canceled and shares of NRG s new common stock were distributed to the holders of certain classes of claims. From December 5, 2003 to March 24, 2004, NRG s common stock was listed on the OTC Bulletin Board under the symbol NRGE.OB. Since March 25, 2004, NRG s common stock has been listed for trading on the New York Stock Exchange under the symbol NRG. The following table sets forth the quarterly high and low share price information for the periods indicated.

	High	Low
Year Ended December 31, 2004		
1st Quarter	$ 22.50	$ 18.10
2nd Quarter	$ 24.80	$ 19.17
3rd Quarter	$ 28.43	$ 24.10
4th Quarter	$ 36.18	$ 26.00
Year Ended December 31, 2005		
1st Quarter	$ 39.10	$ 32.79
2nd Quarter	$ 37.61	$ 30.30
3rd Quarter	$ 44.45	$ 36.40
4th Quarter	$ 49.44	$ 37.60
Year Ended December 31, 2006		
1st Quarter (through January 25, 2006)	$ 49.46	$ 45.50

On January 25, 2006, the closing sale price of NRG s common stock was $49.25. NRG has not declared or paid dividends on its new common stock, although we may do so in the future. The terms of our existing senior secured credit facility and the indenture for the Second Priority Notes restrict, and we expect the terms of our new senior credit facility and the indenture governing the New Senior Notes to restrict, our ability to pay dividends to the holders of our common stock. See Description of Certain Indebtedness New Senior Secured Credit Facility and Description of Certain Indebtedness New Senior Notes. In addition, under the terms of our outstanding preferred stock, including the mandatory convertible preferred stock offered hereby, we are restricted from paying any cash dividend on our common stock if we are not current in our dividend payments with respect to such preferred stock. If we issue the Cumulative Redeemable Preferred Stock to the Sellers pursuant to the Acquisition Agreement, we will be prohibited from paying dividends on our common stock so long as any shares of Cumulative Redeemable Preferred Stock are outstanding. See Description of Capital Stock Preferred Stock.

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SELECTED CONSOLIDATED FINANCIAL INFORMATION OF NRG

The following table presents selected historical consolidated financial information of (i) Predecessor Company as of and for the years ended December 31, 2000, 2001 and 2002 and for the period from January 1, 2003 to December 5, 2003 and (ii) Reorganized NRG for the period from December 6, 2003 to December 31, 2003, as of December 31, 2003, as of and for the year ended December 31, 2004 and the nine months ended September 30, 2005 and 2004. Predecessor Company refers to NRG s operations prior to December 6, 2003, before emergence from bankruptcy and Reorganized NRG refers to NRG s operations from December 6, 2003 onwards, after emergence from bankruptcy.

The selected historical consolidated financial information of Predecessor Company as of and for the year ended December 31, 2000, 2001 and 2002 and for the period from January 1, 2003 to December 5, 2003 is derived from the historical financial information contained in the audited consolidated financial statements of Predecessor Company incorporated by reference in this prospectus supplement.

The selected historical consolidated financial information of Reorganized NRG for the period December 6, 2003 to December 31, 2003 and as of and for the year ended December 31, 2004 is derived from the historical financial information contained in the audited consolidated financial statements of Reorganized NRG incorporated by reference in this prospectus supplement. The summary unaudited historical consolidated financial information as of and for the nine months ended September 30, 2005 and 2004 (i) have been derived from Reorganized NRG s unaudited consolidated financial statements which are incorporated by reference in this prospectus supplement, (ii) have been prepared on a similar basis to that used in the preparation of the audited financial statements of Reorganized NRG and (iii) in the opinion of NRG s management, include all adjustments necessary for a fair statement of the results for the unaudited interim period.

The selected historical consolidated financial information set forth below should be read in conjunction with management s discussion and analysis of financial condition and results of operations and the consolidated financial statements of Predecessor Company and Reorganized NRG and the related notes thereto incorporated by reference into this prospectus supplement. The results for a period of less than a full year are not necessarily indicative of the results to be expected for any interim period.

	Predecessor Company				Reorganized NRG			
	For the Year Ended December 31, 2000	For the Year Ended December 31, 2001	For the Year Ended December 31, 2002	Period from January 1 December 5, 2003	Period from December 6 December 31, 2003	For the Year Ended December 31, 2004	For the Nine Months Ended September 30, 2004	For the Nine Months Ended September 30, 2005
							(unaudited)	(unaudited)
	($ in thousands, except per share data)							
Income Statement Data:								
Total operating revenues	$ 1,664,980	$ 2,085,350	$ 1,938,293	$ 1,798,387	$ 138,490	$ 2,347,882	$ 1,770,669	$ 1,942,828
Legal settlement				462,631				
Fresh start reporting adjustments				(4,118,636)				
Reorganization items				197,825	2,461	(13,390)	(1,656)	

Restructuring and impairment charges			2,563,060	237,575		44,661	42,183	6,223
Total operating costs and expenses	1,308,589	1,703,531	4,321,385	(1,475,523)	122,328	1,955,887	1,459,756	1,861,569
Minority interest in (earnings)/losses of consolidated subsidiaries	(840)				(134)	(16)	(18)	(36)
Equity in earnings of unconsolidated affiliates	139,364	210,032	68,996	170,901	13,521	159,825	117,187	82,501
Write downs and losses on sales of equity method investments			(200,472)	(147,124)		(16,270)	(14,057)	15,894
Income/(loss) from continuing operations	149,729	210,502	(2,788,452)	2,949,078	11,405	159,144	142,154	6,991

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	Predecessor Company				Reorganized NRG			
	For the Year Ended December 31, 2000	For the Year Ended December 31, 2001	For the Year Ended December 31, 2002	Period from January 1 December 5, 2003	Period from December 6 December 31, 2003	For the Year Ended December 31, 2004	For the Nine Months Ended September 30, 2004	For the Nine Months Ended September 30, 2005
							(unaudited)	(unaudited)
	($ in thousands, except per share data)							
Income/(loss) on discontinued operations, net of income taxes	33,206	54,702	(675,830)	(182,633)	(380)	26,473	25,326	12,612
Net income/(loss)[1]	182,935	265,204	(3,464,282)	2,766,445	11,025	185,617	167,480	19,603
Net income per share basic	NA	NA	NA	NA	$ 0.11	$ 1.86	$ 1.67	$ 0.07
Net income per share diluted	NA	NA	NA	NA	$ 0.11	$ 1.85	$ 1.67	$ 0.07
Weighted average shares outstanding basic (in millions)	NA	NA	NA	NA	100	100	100	86
Weighted average shares outstanding diluted (in millions)	NA	NA	NA	NA	100	100	100	86
Other Financial and Operating Data and Ratios:								
Capital expenditures	$ (223,560)	$ (1,322,130)	$ (1,439,733)	$ (113,502)	$ (10,560)	$ (114,360)	$ (78,293)	$ (45,518)
Depreciation and amortization	92,673	140,975	207,027	218,843	11,808	208,036	158,603	144,317
Cash flows from operating activities	361,678	276,014	430,042	238,509	(588,875)	643,993	595,421	(113,802)
	1.81x	1.26x	[3]	9.82x[4]	1.68x	1.83x	1.80x	1.19x

Ratio of earnings to fixed charges(2)								
Ratio of earnings to combined fixed charges and preference dividends(2)	1.81x	1.26x	(3)	9.82x(4)	1.68x	1.82x	1.80x	1.04x
Balance Sheet Data (at period end):								
Cash and cash equivalents	$ 36,746	$ 86,738	$ 360,860	395,982	$ 551,223	$ 1,103,678	$ 1,098,782	$ 504,336
Restricted cash	7,236	68,320	211,966	493,047	116,067	109,633	145,571	91,508
Total Assets	5,986,289	12,915,222	10,896,851	9,167,329	9,244,987	7,830,283	8,185,858	7,795,367
Long-term debt:								
Recourse corporate level debt	1,512,386	3,742,400	3,998,280	8,651	2,458,690	2,544,048	2,437,088	1,964,865
Non-recourse project level debt	1,689,954	3,946,811	4,814,432	3,386,434	1,689,340	1,179,806	1,131,764	1,077,533
Total long-term debt including current maturities	3,202,340	7,689,211	8,812,712	3,395,085	4,148,030	3,723,854	3,568,852	3,042,398
Stockholders equity/(deficit)	1,462,088	2,237,129	(696,199)	2,404,000	2,437,256	2,692,164	2,597,151	2,019,168

(1) Our results include the following items that have had a significant impact on our operations during the periods indicated below:

	Predecessor Company				**Reorganized NRG**			
	For the Year Ended December 31, 2000	**For the Year Ended December 31, 2001**	**For the Year Ended December 31, 2002**	**Period from January 1 December 5, 2003**	**Period from December 6 December 31, 2003**	**For the Year Ended December 31, 2004**	**For the Nine Months Ended September 30, 2004**	**For the Nine Months Ended September 30, 2005**
							(unaudited)	**(unaudited)**
	($ in thousands, except per share data)							

Income/(loss) on discontinued operations, net of income taxes	$ 33,206	$ 54,702	$ (675,830)	$ (182,633)	$ (380)	$ 26,473	$ 25,326	$ 12,612
Legal settlement				462,631				

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	Predecessor Company					Reorganized NRG		
	For the Year Ended December 31, 2000	For the Year Ended December 31, 2001	For the Year Ended December 31, 2002	Period from January 1 December 5, 2003	Period from December 6 December 31, 2003	For the Year Ended December 31, 2004	For the Nine Months Ended September 30, 2004 (unaudited)	For the Nine Months Ended September 30, 2005 (unaudited)
	($ in thousands, except per share data)							
Fresh start reporting adjustments				(4,118,636)				
Corporate relocation charges						16,167	12,474	5,651
Reorganization items				197,825	2,461	(13,390)	(1,656)	
Restructuring and impairment charges			2,563,060	237,575		44,661	42,183	6,223
Write downs and gains/(losses) on sales of equity method investments			(200,472)	(147,124)		(14,057)	(16,270)	15,894
FERC authorized settlement						(38,357)	(38,357)	
Write down of Note Receivable						4,572	4,572	

(2) The ratio of earnings to fixed charges is computed by dividing earnings by fixed charges. The ratio of earnings to fixed charges and preference dividends is computed by dividing earnings by fixed charges and preference dividends. For this purpose, earnings includes pre-tax income (loss) before adjustments for minority interest in our consolidated subsidiaries and income or loss from equity investees, plus fixed charges and distributed income of equity investees, and amortization of capitalized interest reduced by interest capitalized. Fixed charges include interest, whether expensed or capitalized for both continuing and discontinued operations, amortization of debt expense and the portion of rental expense that is representative of the interest factor in these rentals. Preference dividends equals the amount of pre-tax earnings that is required to pay the dividends on outstanding preference securities.

(3) For the year ended December 31, 2002, the deficiency of earnings to fixed charges was $3,023 million.

(4) For the period January 1, 2003 through December 5, 2003, the earnings include a one time earning of $4,119 million due to Fresh Start adjustments.

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SELECTED CONSOLIDATED FINANCIAL INFORMATION OF TEXAS GENCO

The following table sets forth selected historical consolidated financial information for Texas Genco LLC and its subsidiaries and for Texas Genco Holdings, Inc., Texas Genco LLC s predecessor for financial reporting purposes, and its subsidiaries. Because Texas Genco LLC acquired Texas Genco Holdings, Inc. as part of a multi-step transaction in which the Initial Acquisition (as described below) was consummated on December 15, 2004 and the Nuclear Acquisition (as described below) was consummated on April 13, 2005, information is presented for (i) Texas Genco Holdings, Inc. as of and for the years ended December 31, 2002, 2003 and 2004, and as of and for the nine months ended September 30, 2004 and for the period from January 1, 2005 through April 13, 2005 and (ii) Texas Genco LLC as of December 31, 2004, the period from July 19, 2004, or Inception, through December 31, 2004 and as of and for the nine months ended September 30, 2005.

The selected historical consolidated financial information for Texas Genco Holdings, Inc. as of and for the years ended December 31, 2000, 2001, 2002, 2003 and 2004 were derived from Texas Genco Holdings, Inc. s audited financial statements incorporated by reference into this prospectus supplement. The selected historical consolidated financial information for Texas Genco Holdings, Inc. as of and for the nine months ended September 30, 2004 and for the period from January 1, 2005 through April 13, 2005 (i) were derived from Texas Genco Holdings, Inc. s unaudited financial statements, (ii) have been prepared on a similar basis to that used in the preparation of Texas Genco Holdings, Inc. s audited financial statements, and (iii) in the opinion of Texas Genco s management, include all adjustments necessary for a fair statement of the results for the unaudited interim period. The financial information for Texas Genco Holdings, Inc. reflects ownership of the Non-Nuclear Assets for periods prior to December 15, 2004 and of an undivided 44.0% interest in STP for all periods presented, and is therefore not comparable to the historical financial information for Texas Genco LLC, which reflects ownership of the Non-Nuclear Assets only for periods subsequent to December 15, 2004, the Nuclear Acquisition only for periods subsequent to April 13, 2005 and the ROFR (as described below) only for periods subsequent to May 19, 2005.

The selected historical consolidated financial information for Texas Genco LLC as of December 31, 2004 and for the period from July 19, 2004 (Inception) through December 31, 2004 were derived from the audited consolidated financial statements of Texas Genco LLC incorporated by reference into this prospectus supplement. The selected historical consolidated financial information for Texas Genco LLC as of and for the nine months ended September 30, 2005 (i) were derived from unaudited financial statements of Texas Genco LLC incorporated by reference into this prospectus supplement, (ii) have been prepared on a similar basis to that used in the preparation of the audited financial statements of Texas Genco LLC, and (iii) in the opinion of Texas Genco s management, include all adjustments necessary for a fair statement of the results for the unaudited interim period. The results for a periods for less than a full year are not necessarily indicative of the results to be expected for any interim period. Texas Genco LLC did not exist prior to Inception; therefore, no consolidated financial and other information has been presented in the following table for Texas Genco LLC for any other period.

The selected consolidated historical financial information of Texas Genco LLC and Texas Genco Holdings, Inc. set forth below should be read in conjunction with management s discussion and analysis of financial condition and results of operations and the consolidated financial statements of Texas Genco LLC and Texas Genco Holdings, Inc. and the related notes thereto incorporated by reference into this prospectus supplement.

	Texas Genco Holdings, Inc. Predecessor							Texas Genco LLC[1]	
	For the Years Ended December					For the Nine Months Ended September 30,	Period from January 1, 2005 through April 13, 2005	Period from July 19, 2004 through December 31, 2004	For the Nine Months Ended September 30,
	2000[2]	2001[2]	2002	2003	2004	2004	2005	2004	2005
						(unaudited)			(unaudited)
	($ in millions, except per unit data)								
Statement of Operations Data:									
Revenues[3]	$ 3,334	$ 3,411	$ 1,541	$ 2,002	$ 2,054	$ 1,630	$ 61	$ 96	$ 2,000
Operating expenses									
Fuel and purchased power expense[4]	2,397	2,527	1,083	1,171	1,021	810	6	45	913
Operation and maintenance[5]	393	402	391	411	415	319	35	24	329
Depreciation and amortization	151	154	157	159	89	85	5	13	253
Write-down of assets[6]					763	649			
Gain on sale of assets									(28)
Taxes other than income taxes	63	63	43	39	41	33	3		35
Total	3,004	3,146	1,674	1,780	2,329	1,896	49	82	1,502
Operating income (loss)	330	265	(133)	222	(275)	(267)	12	14	498
Other income	1	2	3	2	5	3	1		3
Interest income (expense), net[7]	(59)	(65)	(26)	(2)				(34)	(134)
	272	202	(156)	222	(270)	(264)	13	(20)	367

Income (loss) before income taxes									
Income tax expense (benefit)[8]	100	74	(63)	71	(171)	(94)	4		21
Income (loss) before cumulative effective of accounting change	172	128	(93)	151	(99)	(170)	9	(20)	346
Cumulative effect of accounting change, net of tax[9]				99					
Net Income (loss)	$ 172	$ 128	$ (93)	$ 250	$ (99)	$ (170)	$ 9	$ (20)	$ 346
Earnings Per Share Data:									
Net income (loss) per share basic	$ 2.15	$ 1.60	$ (1.16)	$ 3.13	$ (1.25)	$ (2.13)	$ 0.14	$ (0.13)	$ 2.05
Net income (loss) per share diluted	2.15	1.60	(1.16)	3.13	(1.25)	(2.13)	0.14	(0.13)	1.98
Weighted average shares outstanding basic (in millions)[10]	80.0	80.0	80.0	80.0	79.4	80.0	64.8	156.5	168.6
Weighted average shares outstanding diluted (in millions)[10]	80.0	80.0	80.0	80.0	79.4	80.0	64.8	156.5	175.1
Other Financial Data:									
Capital expenditures	$ 252	$ 409	$ 258	$ 157	$ 73	$ 46.0	$ 9	$ 6	$ 74
Balance Sheet Data (at period end):									
Property, plant and equipment, net[11]	$ 3,667	$ 3,905	$ 4,096	$ 4,126	$ 474	$ 478	$ 474	$ 2,446	$ 3,542
Total assets[12]	4,032	4,323	4,508	4,640	1,395	4,272	996	4,588	6,099
Total debt							75	2,280	2,743
Net capitalization	2,323	2,624							
Shareholders equity			2,824	3,033	454	2,680	466		
Members equity[12][13]								772	773

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(1) Texas Genco LLC was formed on July 19, 2004 to facilitate the acquisition of Texas Genco Holdings, Inc. in a multi-step transaction from CenterPoint Energy, Inc. and other minority public stockholders. On December 13, 2004, Texas Genco Holdings, Inc. divided its nuclear and non-nuclear generating assets and liabilities between two of its wholly-owned subsidiaries. Its non-nuclear generating assets and liabilities were allocated to Texas Genco II, LP and its nuclear assets and liabilities and its cash were allocated to Texas Genco, LP. The non-nuclear generating assets and liabilities, together with assets and liabilities unrelated to the wholesale generation business held by Texas Genco Services, LP, another wholly-owned subsidiary of Texas Genco Holdings, Inc., are referred to as the Non-Nuclear Assets. On December 14, 2004, Texas Genco Holdings, Inc. merged with a wholly-owned subsidiary of CenterPoint Energy, Inc. As a result of this merger, CenterPoint Energy, Inc. acquired 100% of the issued and outstanding common stock of Texas Genco Holdings, Inc. On December 15, 2004, two wholly-owned subsidiaries of Texas Genco LLC merged with and into Texas Genco II, LP and Texas Genco Services, LP, respectively. As a result of these mergers, referred to as the Initial Acquisition, Texas Genco II, LP and Texas Genco Services, LP became wholly-owned subsidiaries of Texas Genco LLC and Texas Genco LLC thereby acquired the Non-Nuclear Assets. On April 13, 2005, a wholly-owned subsidiary of Texas Genco LLC merged with and into Texas Genco Holdings, Inc. As a result of this merger, which is referred to as the Nuclear Acquisition, Texas Genco Holdings, Inc. became a wholly-owned subsidiary of Texas Genco LLC and Texas Genco LLC thereby indirectly acquired Texas Genco Holdings, Inc. s assets and liabilities, including its indirect 30.8% undivided interest in STP. On May 19, 2005, pursuant to the exercise of a right of first refusal by Texas Genco, LP subsequent to a third party offer to American Electric Power, or AEP, in early 2004, Texas Genco LLC acquired from AEP an additional indirect 13.2% undivided interest, equivalent to 330 MW, in STP for approximately $174.2 million, less adjustments for working capital and other purchase price adjustments. This acquisition is referred to as the ROFR. As a result, Texas Genco LLC, through Texas Genco, LP, owns a 44.0% undivided interest, equivalent to 1,101 MW, in STP. The transactions described above are referred to, collectively, as the The Texas Genco Formation Transactions.

(2) Prior to January 1, 2002, Texas Genco Holdings, Inc. sold power as part of an integrated utility at regulated rates; thereafter, power was sold at market-based rates. Therefore, the historical information included in the Texas Genco Holdings, Inc. financial statements for periods prior to January 1, 2002 does not reflect what the financial position and results of operations of Texas Genco Holdings, Inc. would have been had Texas Genco Holdings, Inc. been operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented.

(3) Revenues for Texas Genco LLC include amortization of the liability related to below-market power sales contracts recorded in connection with the Initial Acquisition and the effect of other non-trading derivatives, which increased revenues by $12.3 million and decreased revenues by $3.6 million, respectively, for the period from Inception through December 31, 2004. For the nine months ended September 30, 2005, amortization of the liability related to below-market power sales contracts increased revenues for Texas Genco LLC by $186.3 million and the effect of other non-trading derivatives decreased revenues for Texas Genco LLC by $28.9 million.

(4) Fuel and purchased power expense for Texas Genco LLC includes fuel-related depreciation and amortization amortization of nuclear fuel and the amortization of the liability related to above-market coal purchase contracts (which contracts expire in 2010) recorded in connection with the Initial Acquisition. Fuel-related depreciation and amortization had no effect on fuel expense for the period of Inception through December 31, 2004 and increased fuel expense by $10.3 million for the nine months ended September 30, 2005. The amortization of the liability related to above-market coal purchase contracts decreased fuel and purchased power expense for Texas Genco LLC by $1.5 million for the period from Inception through December 31, 2004

and $37.0 million for the nine months ended September 30, 2005.

(5) Operation and maintenance for Texas Genco Holdings, Inc. includes allocations of overhead costs from CenterPoint Energy, Inc. Operations and maintenance for Texas Genco LLC includes payments to CenterPoint Energy, Inc. and Reliant Energy, Inc. for transition services. Operations and maintenance for Texas Genco LLC for the nine months ended September 30, 2005 includes a charge of $35.3 million related to our workforce optimization plan and a payment of $7.5 million of monitoring fees paid to affiliates of The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P. and Texas Pacific Group.

(6) For the year ended December 31, 2004, Texas Genco Holdings, Inc. recorded an asset impairment of $763.0 million ($426.0 million net of tax) to reflect the net realizable value for the assets to be sold in the Initial Acquisition. Texas Genco Holdings, Inc. ceased depreciation on its coal, lignite and natural gas-fired generation plants at the time these assets were considered held for sale. This resulted in a decrease in depreciation expense of $69.0 million for the year ended December 31, 2004 as compared to the same period in 2003.

(7) Interest income (expense), net for Texas Genco LLC includes amortization of deferred financing fees of $(1.0) million for the period from Inception through December 31, 2004 and $10.5 million for the nine months ended September 30, 2005.

(8) Texas Genco LLC is a limited liability company that is treated as a partnership for U.S. federal income tax purposes and is, therefore, not itself subject to federal income taxation. Profits or losses are subject to taxation at the member interest level. Texas Genco Holdings, Inc., holds an indirect 44.0% undivided interest in STP and is a corporation that is subject to U.S. federal income taxation on its income.

(9) Cumulative effect of an accounting change resulting from the allocation of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

(10) Texas Genco Holdings, Inc. s Board of Directors declared an 80,000,000-for-one stock split that was effected on December 18, 2002. On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80,000,000 outstanding shares of Texas

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Genco s common stock to CenterPoint Energy s shareholders. Earnings per share has been presented as if the 80,000,000 shares were outstanding for all historical periods in accordance with Statement of Financial Accounting Standards (SFAS) No. 128, Earnings Per Share.

(11) In accordance with ERCOT rules, Texas Genco has placed four units into mothball status for more than 180 days, retired one unit, sold one unit and intends to sell eight units, together representing approximately 3,378 MW of available capacity. Texas Genco placed one additional unit representing approximately 461 MW of net capacity, which was operated pursuant to a reliability must run contract with the ERCOT, into mothball status for more than 180 days when the contract terminated on October 29, 2005. On November 14, 2005, Texas Genco completed the sale of its natural gas-fired generation plant at Deepwater, representing 174 MW of available capacity.

(12) Total assets and members equity as of September 30, 2005 reflects distributions to members of an aggregate of \$85.8 million from July 1, 2005 through September 30, 2005, representing preliminary distributions of net proceeds relating to certain asset sales.

(13) Members equity includes capital contributions from Texas Genco s existing equityholders of \$899.5 million, of which \$892.2 million was contributed by the investment funds affiliated with The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P. and Texas Pacific Group and \$7.3 million was contributed by certain members of Texas Genco s management team.

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LIQUIDITY AND CAPITAL RESOURCES DISCUSSION

Our unaudited pro forma combined financial information incorporated by reference into this prospectus supplement does not purport to represent what our financial condition would actually have been had the Acquisition and the Financing Transactions in fact occurred on the dates specified below or to project our results of operations for any future period. See Risk Factors Risks Related to the Acquisition Because the historical and pro forma financial information incorporated by reference or included elsewhere in this prospectus supplement 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, Texas Genco and your investment decision. In addition, the closing of this offering is not conditioned on the consummation of the Acquisition. While we expect that the Acquisition will be consummated in or about the first week of February 2006, no assurance can be given that the Acquisition will be completed in accordance with the anticipated timing or at all. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay. For information regarding NRG s management s discussion and analysis of financial condition and results of operations, see Incorporation of Certain Documents by Reference and Where You Can Find More Information.

The adjustments reflected in our unaudited pro forma financial information are based on available information and assumptions we believe are reasonable, including our assumptions regarding the financing for the Acquisition that may prove to be inaccurate. See Risk Factors Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business elsewhere in this prospectus supplement.

Basis of Presentation

On September 30, 2005, NRG entered into the Acquisition Agreement with Texas Genco and the Sellers. Under the Acquisition Agreement, NRG agreed to purchase from the Sellers 100% of the outstanding equity interests of Texas Genco. After the completion of the Acquisition, Texas Genco will become a 100% wholly-owned subsidiary of NRG. The Acquisition is currently expected to close in the first quarter of 2006. For a discussion of the Acquisition, see The Acquisition.

The Management s Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, for NRG and Texas Genco incorporated by reference into this prospectus supplement were based upon each of their respective historical financial statements, and should each be read together with their respective historical consolidated financial statements, the notes to those financial statements and the other financial information incorporated by reference or appearing elsewhere in this prospectus supplement. Because neither NRG s nor Texas Genco s historical financial statements reflect the Acquisition and the Financing Transactions, a discussion of NRG s and Texas Genco s historical results of operations do not provide a sufficient understanding of the financial condition and results of operations of our business after giving effect to the consummation of the Acquisition and the Financing Transactions.

NRG s historical financial statements for the 2003 fiscal year are not comparable to its current financial statements. 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 s historical financial statements are not comparable to its current financial

statements. Texas Genco did not exist prior to July 19, 2004 and, accordingly no comparative financial information for prior periods is available.

The pro forma results also include adjustments for the following transactions that either occurred after the announcement of the Acquisition or pursuant to applicable rules are reflected in our pro forma results:

(i) 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. For purposes of these pro forma statements we have reflected the sale of assets of Audrain as a discontinued operation. The purchase price is $115 million, subject to customary purchase price adjustments. The transaction is expected to close during the first half of 2006. The sale is subject to customary approvals, including FERC, Missouri Public Utilities Commission, Illinois Commerce Commission, and Hart-Scott-Rodino review. We expect to record a gain of approximately $15 million at closing.

(ii) On May 19, 2005, pursuant to the exercise of a right of first refusal, or the ROFR, by Texas Genco, subsequent to a third party offer to American Electric Power, or AEP, in early 2004, Texas Genco acquired from AEP an additional 13.2% undivided interest in South Texas Project, or STP. As a result, Texas Genco now owns a 44.0% undivided interest in STP. For pro forma purposes, NRG has accounted for the ROFR as a business acquisition and included the ROFR in our pro forma adjustments to the statements of operation.

(iii) On December 27, 2005, NRG entered into two purchase and sale agreements for projects co-owned with Dynegy, Inc. Under the agreements, NRG will acquire Dynegy s 50 percent ownership interest in WCP Holdings, and become the sole owner of WCP s 1,808 MW of generation in Southern California. In addition, NRG is selling to Dynegy its 50 percent ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. These transactions are conditioned upon each other and NRG will pay Dynegy a net purchase price of $160 million at closing. NRG will effectively fund the net purchase price with cash held by WCP. NRG anticipates closing both transactions during the first quarter 2006. For purposes of these pro forma financial statements, we have assumed that the fair value of our equity investment in Rocky Road is equal to the negotiated price of $45 million. The current cost of our investment in Rocky Road is $70.2 million as of September 30, 2005 and we will record an impairment in our investment due to an other-than-temporary loss in our Rocky Road investment in the amount of $25.2 million.

For these reasons, our discussion below focuses on a discussion of our pro forma combined financial position as of September 30, 2005, which is included in a Current Report on a Form 8-K filed on December 21, 2005 as amended by our current report on From 8-K/A as filed on January 5, 2006, our current report on Form 8-K/A as filed on January 23, 2006 and our current report on Form 8-K/A as filed on January 26, 2006, and incorporated by reference into this prospectus supplement.

This pro forma financial information may not reflect what our financial position would have been had we operated on a combined basis and may not be indicative of what our financial position will be in the future.

The discussion below contains certain statements of a forward-looking nature that involve risks and uncertainties. As a result of many factors, including those set forth under the sections entitled Disclosure Regarding Forward-Looking Statements and Risk Factors and those appearing elsewhere in this prospectus supplement, actual results may differ materially from those anticipated by such forward-looking statements.

Liquidity and Capital Resources

We plan to enter into a new senior secured credit facility for up to an aggregate amount of $5.575 billion to replace our existing senior credit facility. The senior secured credit facility is expected to consist of a $3.575 billion senior first priority secured term loan facility, a $1.0 billion senior first priority secured revolving credit facility and a $1.0 billion senior first priority secured synthetic letter of credit facility. Morgan Stanley

Senior Funding, Inc., an affiliate of one of the underwriters for this offering, will be the administrative agent and one of its affiliates will be the collateral agent pursuant to the new senior secured credit facility. Citigroup Global Markets Inc., one of the underwriters for this offering, will be the syndication agent. Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc. will be the joint lead book runners, joint lead arrangers and co-documentation agents thereunder. Morgan Stanley Senior Funding, Inc., Citigroup Global Markets Inc., Lehman Commercial Paper Inc., Bank of America, N.A., Deutsche Bank AG Cayman Islands Branch, Merrill Lynch Capital Corporation and Goldman Sachs Credit Partners L.P., each an underwriter or an affiliate of one of the underwriters for this offering, will be lenders under the new senior secured credit facility.

We expect to draw down approximately $3.575 billion from the term loan facility to be used together with the net proceeds (after giving effect to underwriting discounts and commissions) of approximately $3.53 billion from the notes offering, the offerings of common stock of $1.0 billion, $0.5 billion in mandatory convertible preferred stock and additional cash on hand, to finance the Acquisition, to repay $2 billion of our indebtedness and $2.7 billion of Texas Genco s outstanding indebtedness and to pay related fees and expenses. Also see Use of Proceeds Sources and Uses of Funds.

The new senior secured credit facility will be guaranteed by substantially all of our subsidiaries, with certain customary or agreed-upon exceptions for immaterial subsidiaries and subsidiaries defined as unrestricted, foreign subsidiaries and certain project subsidiaries. In addition, it will be secured by liens on substantially all of our assets and the assets of our subsidiaries, with certain customary or agreed-upon exceptions for foreign subsidiaries, certain project subsidiaries and other subsidiaries or assets, and by a pledge of certain of our subsidiaries capital stock.

The term loan, the revolving credit and the synthetic letter of credit facilities will mature in seven, five and seven years, respectively, from the closing date of the new senior secured credit facility. The term loan facility amortizes on a quarterly basis as described in Description of Certain Indebtedness New Senior Secured Credit Facility. Borrowings under the new senior secured credit facility bear interest at an alternate base rate (calculated on the basis of prime rate) plus an applicable margin, or at an adjusted Eurodollar rate (calculated on the basis of the LIBO rate) plus an applicable margin, in each case as described in Description of Certain Indebtedness New Senior Secured Credit Facility.

There are certain affirmative and negative covenants (including financial covenants) placed on us under the new senior secured credit facility, including, but not limited to, restrictions on equity issuances, payment of dividends on or capital stock, the issuance of additional debt, incurrence of liens and capital expenditures, as further described in Description of Certain Indebtedness New Senior Secured Credit Facility.

As of September 30, 2005, on a pro forma basis after giving effect to the Acquisition and the Financing Transactions, our new senior first priority secured term loan facility would be drawn in its entirety, $1 billion of borrowings would be available under our new senior first priority secured revolving credit facility and $1 billion of undrawn letters of credit capacity would have been available under our new senior first priority secured synthetic letter of credit facility. As of September 30, 2005, on a pro forma basis after giving effect to (i) the sale of Audrain; (ii) the inclusion of the results pursuant to the ROFR; (iii) the refinancing of NRG s old debt structure; (iv) the remaining Financing Transactions and subsequent Acquisition; and (v) the acquisition of the remaining 50% ownership interest in WCP Holdings and the sale of our 50% ownership interest in Rocky Road, we would have had approximately $8.0 billion of indebtedness, which includes the notes and amounts outstanding under our new senior secured credit facility. Of this total, approximately $3.575 billion would have been our secured indebtedness and the secured indebtedness of our subsidiaries. Interest payments on the notes and on borrowings under the new senior secured credit facility will significantly increase our liquidity requirements. See Capitalization.

Certain of our subsidiaries and affiliates are subject to project financing. Such entities will not guarantee our obligations on the notes. The debt agreements of these subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to us. On a pro forma basis, giving effect to (i) the sale of Audrain; (ii) the inclusion of the results pursuant to the ROFR; (iii) the refinancing of NRG s old debt structure; (iv) the remaining Financing Transactions and subsequent Acquisition; and (v) the acquisition of the remaining 50% ownership interest in WCP Holdings and the sale of our 50% ownership interest in Rocky Road, our guarantor subsidiaries would have represented approximately 90% of our revenues from wholly owned subsidiaries for the fiscal year ended December 31, 2004, and the nine months ended September 30, 2005. On a pro forma basis, our guarantor subsidiaries would have held approximately 90% of our consolidated assets as of September 30, 2005, and our non-guarantor subsidiaries would have had approximately $781 million in aggregate principal amount of funded indebtedness as of September 30, 2005. Our outstanding consolidated trade payables would have been $339 million as of September 30, 2005, on a pro forma basis. On a pro forma basis, approximately 77% of these trade payables would have constituted obligations of NRG and our guarantor subsidiaries.

We expect that our 2006 total capital expenditures will be approximately $295.5 million and will relate to the operation and maintenance of our existing generating facilities. Also, see further discussions in the respective management s discussion and analysis of financial condition and results of operations of NRG Energy, Inc. and Texas Genco incorporated herein by reference.

Texas Genco entered into a power purchase agreement with J. Aron & Company, the commodities trading subsidiary of Goldman Sachs & Co, which we refer to as J. Aron and the related agreement as the J. Aron PPA. Under the J. Aron PPA, Texas Genco sold forward, on a fixed price basis, a substantial portion of its expected ERCOT generation capacity beginning January 1, 2005 through December 31, 2010. As a result of the J. Aron PPA and certain power sales and gas swap transactions, approximately 26% of Texas Genco s net baseload generation capacity in Texas, and approximately 16% of the combined company s total net baseload capacity, as measured in MWh through 2010 has been sold on a fixed price basis to J. Aron, making J. Aron one of the combined company s largest customers on a going forward basis.

As collateral for Texas Genco s obligations under the J. Aron PPA and certain power sales and gas swap transactions, Texas Genco agreed to post letters of credit and grant a second lien on Texas Genco s assets in favor of J. Aron. For a detailed description of these credit support arrangements, see Description of Certain Indebtedness. The obligations of J. Aron under the J. Aron PPA and a subsequent natural gas swap are supported by an unlimited guarantee from J. Aron s parent, The Goldman Sachs Group, Inc.

Six other trading counterparties have similar arrangements with Texas Genco related to hedging agreements through December 31, 2010 collateralized by letters of credit and a retained second lien on the Texas Genco s assets. These additional six counterparties comprise approximately 22% of Texas Genco s net baseload capacity in Texas, and approximately 13% of the combined company s total net baseload capacity, as measured in MWh through December 31, 2010. NRG expects that, at the closing of the Acquisition and the Financing Transactions, the collateral arrangements described above, including with respect to certain counterparts holding second liens on the ERCOT assets, will remain in place or will be replaced with substitute collateral arrangements comprising an interest in a second lien position on substantially all of NRG s assets. On a going forward basis, NRG intends to secure some or all of its commodity hedging activities with interests in a second lien position on substantially all of NRG s assets. There can be no assurance that this second lien position will provide enough capacity to cover all commodity hedges that are necessary or desirable for adequately hedging NRG s commodity risk. See Risk Factors Risks Related to the Operation of our Business We may not have sufficient liquidity to hedge market risks effectively.

As discussed in the Business section in respect to Texas Genco s forward power sales, our revenues and cash flows from operations from forward power sales will decrease from $1.6 billion to $1.4 billion due to a reduction in the average contracted rates, from $44 per MWh to $39 per MWh. Total MWh s sold remains substantially the same. This reduction in the contracted price will reduce the revenues and cash flows from operations of the combined company by approximately $209 million during 2007 in comparison to 2006. However, based upon our current level of operations, we believe that our existing cash and cash equivalents balances and our cash from operating activities, together with available borrowings under our new senior secured credit facility will be adequate to meet our anticipated requirements for working capital, capital

expenditures, commitments, contingent purchase prices, program and other discretionary investments, and interest and principal payments for at least the next twenty-four months.

In the event that NRG is unable to raise sufficient proceeds through the consummation of the common stock offering and/or the New Senior Notes offering described elsewhere in this prospectus supplement, NRG may draw down, in whole or in part, on a $5.1 billion bridge loan facility made available to it by the bridge lenders in order to finance the Acquisition. See Description of Certain Indebtedness Bridge Loan Facility. In the event of such draw down, we would be significantly more highly leveraged, which means we will have a larger amount of indebtedness in relation to our stockholders equity. Our interest expense would significantly increase and require us to dedicate a substantial portion of our cash flow from operations to payments in respect of our outstanding indebtedness. Our substantial indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under our debt instruments. In the event that NRG does not consummate the common stock and New Senior Notes offerings as currently contemplated and elects not to consummate the financing under the bridge loan facility, it could seek alternative sources of financing for the Acquisition, which may include, among other alternatives, the issuance in part of senior secured debt securities or borrowing in part on a senior secured basis. There can be no assurance as to the terms on which NRG would issue these senior secured debt securities or borrow funds. We are unable to predict the interest rate payable on any such debt or give any assurance that the terms would not restrict our financial flexibility or limit our ability to operate our business. See Risk Factors Risks Related to the Offering If NRG is unable to raise sufficient proceeds through other Financing Transactions described elsewhere in this prospectus supplement, NRG may draw down on a bridge loan facility in order to close the Acquisition which would significantly increase our indebtedness. If NRG elects not to consummate the financing under the bridge loan facility, NRG may seek alternative sources of financing for the Acquisition, the terms of which are unknown to us and could limit our ability to operate our business.

BUSINESS

In this section, NRG refers to NRG Energy, Inc. together with its consolidated subsidiaries, and Texas Genco refers to Texas Genco LLC, together with its consolidated subsidiaries. On September 30, 2005, NRG entered into a definitive agreement to acquire Texas Genco. We, our, us, the combined company and the Company refer to NR Texas Genco on a combined basis, together with their consolidated subsidiaries, after giving pro forma effect to the completion of the Acquisition and the Financing Transactions. 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 September 30, 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). The MW and MWh figures and other operational figures related to the combined company only give pro forma effect to the Acquisition and the Financing Transactions.

The closing of this offering is not conditioned on the consummation of the Acquisition. While we expect that the Acquisition will be consummated in or about the first week of February 2006, no assurance can be given that the Acquisition will be completed in accordance with the anticipated timing or at all. See Risk Factors Risks Related to the Offering There can be no assurance that the Acquisition will be consummated in accordance with the anticipated timing or at all, and the closing of this offering is not conditioned on the consummation of the Acquisition. If the Acquisition is not consummated, NRG s common stock, and therefore our mandatory convertible preferred stock, will not reflect any actual or anticipated interest in Texas Genco, and if the Acquisition is delayed, this interest will not be reflected during the period of delay. For more information regarding the business and operations of NRG, see Incorporation of Certain Documents by Reference and Where You Can Find More Information.

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 of energy, capacity and related products in the competitive markets in which we operate. As of September 30, 2005, the combined company would have had a total global portfolio of 235 operating generation units at 62 power generation plants, with an aggregate generation capacity of approximately 25,041 MW. Within the United States, the combined company will have one of the largest and most diversified power generation portfolios with approximately 23,124 MW of generation capacity in 213 generating units at 54 plants as of September 30, 2005. These power generation facilities are primarily located in our core regions in the Electric Reliability Council of Texas, or ERCOT, market (approximately 11,119 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, which we refer to as the merit order, 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.

Our Strategy

Our strategy is to increase the value of, and extract maximum value from, our generation assets while using that asset base as a platform for enhanced financial performance which can be sustained and expanded upon the 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

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bulk power requirements of our customer base and other entities who offer load, or otherwise consume wholesale electricity products and services in bulk. Our strategy includes the following elements:

Increase value from our existing assets. Following the Acquisition, we believe that we will 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 believe that 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 the merit order.

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 intend to 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 leveraging 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.

Our Competitive Strengths

Scale and diversity of assets. The combined company will have one of the largest and most diversified power generation portfolios in the United States with approximately 23,124 MW of generation capacity in 213 generating units at 54 plants as of September 30, 2005. Our power generation assets will be diversified by fuel type, dispatch level and region, which will help mitigate the risks associated with fuel price volatility and market demand cycles. The combined company s U.S. baseload facilities, which will consist of approximately 8,558 MW of generation capacity measured as of September 30, 2005, will provide the combined company with a significant source of stable cash flow, while the combined company s intermediate and peaking facilities, with approximately 14,566 MW of generation capacity as of September 30, 2005, will 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 will have dual or multiple fuel capability, which will allow most of these plants to dispatch with the lowest cost fuel option.

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

Approximate U.S. Portfolio Net Capacity By Fuel Type[(1)]	**Approximate U.S. Portfolio Net Capacity By Dispatch Level**	**Approximate U.S. Portfolio Net Capacity By Region**

(1) Reflects only domestic generation capacity; 19 MW of wood-fired generation capacity not shown. Also includes 461 MW of generation capacity from facilities that were mothballed after September 30, 2005.

Reliability of future cash flows. We have sold forward a significant amount of our expected baseload generation capacity for 2006 and 2007. As of September 30, 2005 the combined company would have sold forward 68% of its baseload generation in the Texas (ERCOT) market for 2006 through 2009. As of the same date, the combined company would have sold approximately 83% of its expected annual baseload generation in the Southeastern Electric Reliability Council/ Entergy, or SERC Entergy, market for 2006 through 2009, and approximately 70% of its expected annual baseload generation in the Northeast region for 2006. In addition, as of September 30, 2005, the combined company would have purchased forward under fixed price 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 September 30, 2005, approximately 38% of the combined company s domestic generation capacity would have 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 that currently have substantially higher variable costs than our solid fuel baseload power plants. For example, in the ERCOT market, a 2004 report by Henwood found that natural gas-fired power plants set the market price of power more than 90% of the time. 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 combined company will have 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 others, selling power at prevailing market prices during periods of peak demand and providing ancillary services in support of system reliability.

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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 September 30, 2005, Texas Genco s generation assets in the ERCOT market consisted of approximately 5,178 MW of baseload generation assets and approximately 5,941 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 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, as of September 30, 2005, 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, as of September 30, 2005, the ERCOT baseload forward power sales and natural gas swap agreements that extend beyond December 31, 2005 and were transacted through September 30, 2005.

	2006	2007	2008	2009	2010	Annual Average for 2006-2007	Annual Average for 2006-2010
Net Baseload Capacity (MW)(1)	5,294	5,340	5,340	5,340	5,340	5,317	5,331
Total Baseload Sales (MW)(2)	4,274	4,271	4,152	3,428	1372	4,273	3,499
Total Available Baseload Capacity Sold Forward	81%	80%	78%	64%	26%	80%	66%
Weighted Average Forward Price ($ per MWh)(3)	$ 44	$ 39	$ 41	$ 48	$ 52	$ 42	$ 45
Total Revenues Sold Forward ($ in millions)	$ 1,654	$ 1,445	$ 1,505	$ 1,434	$ 621	$ 1,553	$ 1,333

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(1) Net Baseload Capacity represents nominal summer net megawatt capacity of power generation adjusted for ownership, known upgrades and excluding capacity from mothballed units as of September 30, 2005. Capacity verification is based upon independent system operator, or ISO, required annual or semi-annual testing requirements.

(2) 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/ MWh, mid-point of the bid and offer as quoted by brokers in the market of the relevant Electric Reliability Council of Texas zones as of September 19, 2005) to arrive at the equivalent MWh hedged which is then divided by 8,760 to arrive at MW hedged.

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

Northeast

As of September 30, 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 L.L.C., 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 September 30, 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.

South Central

As of September 30, 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. As of September 30, 2005, 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. As of September 30, 2005, approximately 2,140 MW of NRG s generation capacity in the region was sold forward pursuant to long-term contracts. 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 as of September 30, 2005.

Western

As of September 30, 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. As of September 30, 2005, 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. The transaction, which is subject to regulatory approval, is expected to close in the first quarter of 2006.

We plan to continue the operations of the existing plants and also to redevelop our sites with new facilities when economic, market and regulatory conditions are favorable. However, in the alternative, we also believe we could recover our investment by selling or redeveloping the properties for other uses.

Other

As of September 30, 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 owned, as of September 30, 2005, interests in power plants having a generation capacity of approximately 1,916 MW in Australia, Germany and Brazil, and interests in coal mines in Australia and 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. The combined company will perform its own power marketing, which is focused on maximizing value and managing volatility through asset-based power and fuel marketing and trading activities in the spot, intermediate and long-term markets. Our principal objectives are the realization of the full market value of our asset base, including the capture of our 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.

As of September 30, 2005, the combined company, after giving effect to the Acquisition and Financing Transactions, had collateral (including cash, letters of credit and junior liens) posted to support commercial operations totaling \$3.66 billion. The following table summarizes, as of September 30, 2005, the combined company collateral posted by credit rating.

Credit Rating	Letters of Credit(2)	Cash(2)	Junior Liens	Collateral Posted
A- and above	\$ 633,034,400	\$ 570,323,548	\$ 2,179,220,554	\$ 3,382,578,502
BBB- through BBB+	\$ 167,349,108	\$ 54,210,141	\$ 1,739,911	\$ 223,299,160
Below BBB-	\$ 7,771,000	\$ 3,895,000	\$ 0	\$ 11,666,000
Not Rated(1)	\$ 38,201,000	\$ 2,968,992	\$ 0	\$ 41,196,992
Total	\$ 846,355,508	\$ 631,397,681	\$ 2,180,960,464	\$ 3,658,713,654

(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.

(2) As of September 30, 2005, WCP had collateral posted totaling \$24.6 million, which is excluded from the table above. Of this amount, letters of credit totaled \$10.7 million and cash totaled \$13.9 million.

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. Coal hedging is dynamic based on forecasted generation and market volatility.

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

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of the top five coal purchasers in the United States. In addition, as of September 30, 2005, approximately 92% of the combined company s coal-fired generation would have benefited from multiple sourcing and transportation alternatives. As of September 30, 2005, on a pro forma basis, the combined company would have had approximately 6,000 privately leased or owned rail cars in its transportation fleet. In addition, we intend to enter into contracts for delivery of an additional 2,695 rail cars within the next two years of which approximately 1,410 will replace a portion of our existing rail car fleet. The combined company 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. Texas Genco is 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
Yellow cake U_3O_8 (30-40% of total fuel cost). Conversion to uranium hexafluoride (UF_6) (3-5% of total fuel cost).	Contracts with Cameco (Canada) and Cogema/Arriba (France) combine these steps.	100% covered under favorable contracts through mid-2011 and then 25% covered through 2021.
Enrichment of U235 content (35-45%).	Urenco (Germany), Cogema/Arriba (France), Louisiana Enrichment Services, or LES[(1)] (joint venture between Westinghouse & Urenco).	Urenco and Cogema contracts cover through. Balance of current license period under contract with Urenco/LES.
Fabrication of fuel rods (15-20%).	Westinghouse.	Contract covers life of operating license.

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

Credit Support and Collateral Arrangements

In order to secure performance under our power purchase agreements, fuel supply contracts and hedging agreements, we are required to provide credit support to our counterparties from time to time. This credit support consists of a combination of letters of credit, cash, guarantees and junior liens on our assets. For a detailed description of our collateral arrangements, see Description of Certain Indebtedness and Liquidity and Capital Resources Discussion.

Significant Customers

For the nine months ended September 30, 2005, the combined company derived approximately 52% of its total revenues from majority-owned operations from four customers: NYISO accounted for 19%, a subsidiary of Reliant Energy, Inc. accounted for 17%, BP Energy Company accounted for 9% and ISO-NE accounted for 7%. The combined company accounts for the revenues attributable to these customers as part of its North America power generation segment.

ISO-NE and NYISO are ISOs or RTOs and are FERC-regulated entities that administer day-ahead and real-time energy markets, capacity and ancillary service markets and manage transmission assets collectively under their respective control to provide non-discriminatory access to the transmission grid. We anticipate that NYISO and ISO-NE will continue to be significant customers given the scale of our asset base in these areas.

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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.

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 also improved the operational flexibility and financial performance of these plants. During the same time period, NRG will 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 has spent over $700 million on NO_x reduction initiatives since 1999 to ensure both regulatory compliance and continued performance.

The following table summarizes the key existing and planned environmental controls on our coal-fired units:

	SO_2		NO_x		Hg		Particulate	
Units	**Control Equipment**	**Install Date**	**Control Equipment**	**Install Date**	**Control Equipment**	**Install Date**	**Control Equipment**	**Install Date**
Huntley 67	Wet FGD(1)	2013	SNCR	2010	FF-ACI(2)	2011	ESP	1973
Huntley 68	Wet FGD(1)	2013	SNCR	2011	FF-ACI(2)	2009	ESP	1973
Dunkirk 1	None		SNCR	2010	FF-ACI(2)	2010	ESP	1974
Dunkirk 2	None		SNCR	2011	FF-ACI(2)	2011	ESP	1974
Dunkirk 3	None		SNCR	2010	FF-ACI(2)	2011	ESP	1975
Dunkirk 4	None		SNCR	2011	FF-ACI(2)	2010	ESP	1976
Indian River 1	In-Duct Scrubber	2012	SNCR & LNB(3)	2008	Co-Benefit of Scrubbers	2012	ESP (IR1- 3)	1976
Indian River 2	In-Duct Scrubber	2013	SNCR & LNB(3)	2008	Co-Benefit of Scrubbers	2013	ESP (IR1- 3)	1976
Indian River 3	In-Duct Scrubber	2012	LNB(3) & SNCR upgrade	2008	Co-Benefit of Scrubbers	2012	ESP (IR1- 3)	1980
Indian River 4	Dry Scrubber	2011	LNB(3) & SNCR upgrade	2008	Co-Benefit of Scrubbers	2011	ESP (IR1- 3)	1980
Big Cajun 2 U1	Dry Scrubber	2011	None		ACI(2)	2012	ESP	1981
Big Cajun 2 U2	Dry Scrubber	2010	SCR(4)	2010	ACI(2)	2011	ESP	1981
Big Cajun 2 U3	Dry Scrubber	2013	SCR(4)	2013	ACI(2)	2014	ESP	1983
Limestone	FGD	1986-87	LNB/OFA(3)	2000-01			ESP	1986-87

					Co-Benefit of Scrubbers		
WA Parish U 5-7	None	NA	SCR & LNB/OFA (3)	2000-04	None	FF	1988
WA Parish U 8	FGD	1982	SCR & LNB/OFA (3)	2000-04	Co-Benefit of Scrubber	FF	1988

(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 2005, NRG introduced a comprehensive, company-wide cost and revenue enhancement program with the goal of increasing its return on invested capital, or ROIC. This effort has been branded as *FOR*NRG, 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 plants and regional

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and headquarters operations including forced outage reductions and heat rate improvements at NRG s major base load facilities.

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. Discussions are already underway to compare best practices and results between NRG and Texas Genco, to manage suppliers with our combined volumes and to incorporate existing and future Texas Genco processes under the *FOR*NRG program.

Regional Business Descriptions

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

TEXAS (ERCOT)

The combined company s largest business unit will be located in the Texas (ERCOT) region of the United States and will be comprised of investments in generation facilities located in the physical control areas of the ERCOT-ISO.

Operating Strategy

Texas Genco s 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 will be four pronged: (1) to ensure the availability of the baseload plants to fulfill their commercial obligations given the long-term forward sales 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.

Given our strategy of selling forward up to 80% of Texas Genco s solid-fuel baseload capacity under long-term contracts, our primary focus will be to keep Texas Genco s solid-fuel baseload units running. The performances at STP, W. A. Parish and Limestone have been above broader industry averages for the recent five-year period as shown below:

	Average 5-Year Availability Factor	Benchmark Average Availability Factor
Limestone	89.4	85.4
W. A. Parish	87.8	83.6
South Texas Project	87.8	88.9

The operations and maintenance teams will continue to focus on maintaining and improving these levels.

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, Texas Genco offers a range of products including virtual units where the customer has the right to dispatch Texas Genco s 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.

Lastly, we believe that we can have a positive impact on the evolution of the regulatory environment and market structure in Texas. We take our responsibility to the market and the state seriously and will be focused on working broadly with the full suite of stakeholders including other market participants, the PUCT, ERCOT, and the legislature to make Texas attractive for energy infrastructure investment in a way that ensures reliability and increases stability.

Facilities

The following table describes Texas Genco s electric power generation plants and generation capacity as of September 30, 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
P.H. Robinson[5]	Bacliff, TX	100%	461	Natural Gas
San Jacinto	LaPorte, TX	100%	162	Natural Gas
Total Operating Natural Gas-Fired			5,941	
Total Texas (ERCOT) Region			**11,119**	

(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 after September 30, 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.

(5) P.H. Robinson Unit 2 was placed into inactive status on October 29, 2005.

W. A. Parish. Texas Genco s 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 September 30, 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 has invested approximately $430.0 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 uprate projects to be completed by year end 2007 are expected to uprate the net generation capacity of W.A. Parish by 31 MW.

Limestone. Texas Genco s Limestone plant is a lignite and coal-fired plant located approximately 140 miles northwest of Houston. This plant includes two steam generation units with an aggregate generation capacity of 1,614 MW as of September 30, 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. Texas Genco owns the mining equipment and facilities and a portion of the lignite reserves located at the mine. Mining operations are conducted by Texas Westmoreland Coal Co., a single purpose, wholly-owned subsidiary of Westmoreland Coal Company and the owner of a substantial portion of the remaining lignite reserves. Both units have installed low-NO_x burners to reduce NO_x emissions and scrubbers to reduce SO_2 emissions. We plan to upgrade Limestone Unit 2 in the second quarter of 2006 by replacing the high pressure and intermediate pressure turbines, rewinding the generator and replacing the main generator step-up transformer. These upgrades are expected to cost approximately $33.0 million and are expected to increase the 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 upgrade projects to be completed by 2007 are expected to uprate the net generation capacity of STP by 74 MW (33 MW net to Texas Genco). 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 Texas Genco and two other co-owners. Texas Genco 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. Except for certain plant shutdown and decommissioning costs and NRC licensing liabilities, Texas Genco is severally liable, but not jointly liable, for the expenses and liabilities of STP. CenterPoint Energy, Inc., the prior owner of Texas Genco s assets, and the other three original co-owners organized the 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 Texas Genco owns 44% of STP, Texas Genco 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 will remain in effect after the closing of the Acquisition.

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.

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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 since 2000. As of September 30, 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. Texas Genco s coal and nuclear fuel baseload plants represented approximately 5,178 MW, or 26%, of the total solid fuel baseload net generation capacity in the ERCOT market in 2004. ERCOT has established a target equilibrium reserve margin level of approximately 12.5%. Reserve margins will decrease to the extent demand growth exceeds new supply. Overcapacity from new construction could cause some less efficient natural gas-fired units to be retired or mothballed. Overcapacity has little impact on the dispatch of Texas Genco s solid fuel baseload plants given their lower marginal cost relative to natural gas-fired assets.

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, Texas Genco 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. Texas Genco s W. A. Parish plant and all its natural gas-fired plants are located in the Houston zone, Texas Genco 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

Because Texas Genco s generation assets were formerly owned indirectly by a vertically integrated utility, PUCT regulation required firm entitlements to 15% of Texas Genco s operating installed generation capacity to be sold at auction through December 31, 2006, at opening bid prices well below Texas Genco s cost for 2006. On December 7, 2005, Texas Genco filed an application with the PUCT requesting the PUCT to determine that Texas Genco was 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. A decision on this matter is expected by February 2006. In the event the PUCT does not grant Texas Genco s request, Texas Genco s obligation to sell capacity at auction based on this below-cost pricing will continue through December 31, 2006.

J. Aron Power Purchase Agreement

Texas Genco entered into the J. Aron PPA with J. Aron. Under the J. Aron PPA, Texas Genco sold forward, on a fixed price basis, a substantial portion of its expected ERCOT generation capacity beginning January 1, 2005 through December 31, 2010. As a result of the J. Aron PPA and certain power sales and gas swap transactions, approximately 26% of Texas Genco s net baseload generation capacity in Texas, and approximately 16% of the combined company s total net baseload capacity, as measured in MWh through 2010, has been sold on a fixed price basis to J. Aron, making J. Aron one of the combined company s largest customers on a going forward basis.

The J. Aron PPA is a firm, liquidated damages contract. Texas Genco has the flexibility of meeting its obligations to deliver power to specified delivery points under the J. Aron PPA either through sales of power from its plants, or through purchases of power from the market. In addition, if either Limestone in the North zone, or STP in the South zone, has an outage or is derated, Texas Genco is permitted to deliver the power that it is otherwise obligated to deliver in these zones into the Houston zone in satisfaction of its obligations. All Texas Genco s natural gas-fired plants are located in the Houston zone. Additionally, under the J. Aron PPA, Texas Genco does not assume any pricing risk associated with the ERCOT market switching to a nodal pricing market design.

As collateral for Texas Genco s obligations under the J. Aron PPA and certain power sales and gas swap transactions, Texas Genco agreed to post letters of credit and grant a second lien on Texas Genco s assets in favor of J. Aron. For a detailed description of these credit support arrangements, see Description of Certain Indebtedness. The obligations of J. Aron under the J. Aron PPA and a subsequent natural gas swap are supported by an unlimited guarantee from J. Aron s parent, The Goldman Sachs Group, Inc.

In the event power prices decline in the future and J. Aron fails to perform under the J. Aron PPA, Texas Genco would have the right to terminate the J. Aron PPA and collect from J. Aron an amount equal to the difference between the contract price and the lower market price; however, Texas Genco s ability to collect would be dependent on the amount of collateral then posted and the creditworthiness of J. Aron and Goldman at the time. Conversely, in the event power prices rise and Texas Genco fails to perform, J. Aron would have the right to terminate and collect an amount equal to the difference between the contract price and the higher market price. In the event J. Aron terminates, it would have the right to draw on certain letters of credit Texas Genco has posted as collateral. To the extent such letters of credit do not cover the amount of the termination payment, J. Aron retains a second lien on Texas Genco s assets as collateral. J. Aron s right to enforce its lien is limited to higher priority debt having taken such action.

Six other trading counterparties have similar arrangements with Texas Genco related to hedging agreements through December 31, 2010 collateralized by letters of credit and a retained second lien on the Texas Genco s assets. These additional six counterparties comprise approximately 22% of Texas Genco s net baseload capacity in Texas, and approximately 13% of the combined company s total net baseload capacity, as measured in MWh through December 31, 2010. NRG expects that, at the closing of the Acquisition and the Financing Transactions, the collateral arrangements described above, including with respect to certain counterparties holding junior liens on the ERCOT assets, will remain in place or will be replaced with substitute collateral arrangements comprising an interest in a second lien position on substantially all of NRG s assets. On a going forward basis, NRG intends to secure some or all of its commodity hedging activities with interests in a second lien position on substantially all of NRG s assets. There can be no assurance that this second lien position will provide enough capacity to cover all commodity hedges that are necessary or desirable for adequately hedging NRG s commodity risk. See Risk Factors Risks Related to the Operation of our Business We may not have sufficient liquidity to hedge market risks effectively.

Joint Operating Agreement with the City of San Antonio

Texas Genco has a joint operating agreement with the City Public Service Board of San Antonio, or CPS, to jointly dispatch Texas Genco s portfolio of generation units with CPS s portfolio of over 5,300 MW of generation capacity as a joint operating system. This agreement with CPS expires in 2009 and can be terminated at any time by either party with 90 days notice. Texas Genco has delivered a notice of termination to CPS that would have terminated the agreement effective December 31, 2005. However, the parties have since agreed to a short-term extension not expected to extend beyond January 2006.

NORTHEAST REGION

The combined company s second largest asset base will be located in the Northeast region of the United States and will be 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. In the Northeast, 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.

We continue to pursue enhancement of coal assets through continued low sulfur coal conversions, improvements in coal handling and logistics process, and securing adequate coal supplies and transportation commitments. Longer term, we are also focused on working with regulators to gain support and required permits for low sulfur coal conversions.

We continuously work to hedge our baseload portfolio and trade our oil and gas peaking facilities to maximize their value and minimize the risk of being fundamentally long on generation.

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. As discussed further below (see Regulatory Developments Northeast Region RMR Agreements), the RMR agreements are subject to approval by the FERC. In addition to the Connecticut RMR agreements, 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 greenfield development and 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, 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. In addition to redeveloping existing sites, we also have greenfield sites in the Northeast that continue to be evaluated for power plant development opportunities. We also continue to pursue contractual arrangements to support the 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 September 30, 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 as of September 30, 2005 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

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Plant	Location	% Owned	Net Generation Capacity (MW)*	Primary Fuel Type
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. Both Units 20 and 30 were converted from steam engines in the early 1990s. Unit GT-1 produces an aggregate generation capacity of 15 MW and is activated when ConEd issues a generation alarm on hot days and during thunderstorms. 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, NRG s Astoria Gas Turbine 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 net generation capacity of 144 MW each; Units 5, 7 and 8, which are Class 2 turbine engines that have a net generation capacity of approximately 14 MW each; and Units 10, 11, 12 and 13, which are Class 3 turbine engines that have a net generation capacity of 20 MW each. The ten units are further classified into six main substation feeds that provide power to the local New York City load pockets. The Class 1 and Class 2 turbines were installed in 1970 and the Class 3 turbines in 1971. The facility contains retired units, including Units 6 and 9 in Class 2. Units 5 through 8 and units 10 through 13 are expected to retire in 2015, while Units 2 through 4 are expected to be retired in 2022.

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 77 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.

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 85 MW each and were put in service between 1942 and 1954. Units 63 and 64 are inactive and were effectively retired at the end of 2004, and NRG plans to give notice to the New York Public Service Commission of its intent to retire Units 65 and 66 in early 2006 reducing the capacity at this site to approximately 380 MW. As part of a settlement reached with the New York Department of Environmental Conservation, or NYSDEC, in January 2005, NRG will reduce NO_x and SO_x emissions from its Huntley and Dunkirk plants through 2013 in the aggregate by over 80 percent and 86 percent, respectively. A large portion of these reductions will be achieved by switching to low sulfur western coal and related projects for which NRG has already expended or committed significant capital.

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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. The 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 consists 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 are following with 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.

SOUTH CENTRAL REGION

As of September 30, 2005, NRG owned approximately 2,395 MW of generating capacity in the South Central region of the United States, and had obligations to provide up to approximately 2,140 MW of capacity under long-term contracts with 11 rural cooperatives that have terms extending in some cases through 2025. The region lacks a regional transmission organization, or RTO/ ISO and, therefore, remains a bilateral market, making it less efficient than a region with an RTO/ 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 allow us 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.

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 are also evaluating repowering opportunities for the Big Cajun I power stations and 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. We continue to look for opportunities to acquire assets that will enhance our portfolio and long-term strategic goals.

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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 September 30, 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

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

Market Framework

NRG s assets in the South Central region are located within the franchise territories of vertically integrated utilities, primarily Entergy Corporation, 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 September 30, 2005, NRG had long-term all-requirements contracts with 11 Louisiana distribution cooperatives. The agreements are standardized into three types, Form A, B and C and have the terms, contract loads and customers as shown in the table below:

	Term	Contract Load	Customers

Form A	25 yrs.	42%	6
Form B	25 yrs.	3%	1
Form C	9-14 yrs.	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.

In August and September 2005, Hurricanes Katrina and Rita roiled the South Central region s power markets. Although NRG recognized an impairment loss of approximately $1.3 million for hurricane-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. 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 September 30, 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 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 eventually realizing the valuable real estate on which they are located. There are four 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 taking active steps to assess the value of our property for non-power generation purposes. Two of West Coast Power s plants are situated at choice locations on the Pacific coast. Fourth, 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.

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. NRG s strategy is to negotiate with Nevada Power and the steam host to restructure their agreements to provide suitable economic benefits. Alternatively, we expect that we will negotiate a sale of our share of that plant.

Facilities

In May 1999, Dynegy and NRG formed WCP Holdings to serve as the holding company for a portfolio of operating companies that own generation assets in the Southern California market operated by the California ISO, or Cal ISO. This portfolio currently consists of the El Segundo Generating Station, the retired Long Beach Plant Site, the Encina Generating Station and 13 combustion turbines distributed throughout the San Diego area. WCP is directed by an executive committee comprised of two voting members from each of NRG and Dynegy. Under the direction of this executive committee, Dynegy provides power marketing, fuel procurement and accounting services to WCP and NRG provides operations and management services. 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, which is subject to regulatory approval, is expected to close in the first quarter of 2006.

NRG s power generation assets in the Western region as of September 30, 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, which is subject to regulatory approval, is expected to close in the first quarter of 2006.

The following are descriptions of our most significant revenue generating plants in the Western region:

El Segundo. The El Segundo plant, of which NRG currently owns 50%, is located in El Segundo, California and produces aggregate generation capacity of 670 MW from two gas-fired intermediate load units (Units 3 and 4). These units, which have a generation capacity of 335 MW each, were installed in 1964 and 1965, respectively. The plant also contains two retired gas-fired intermediate load units that were installed in 1955 and 1956 (Units 1 and 2). These units, retired in 2002, were capable of producing 175 MW each. WCP is currently in the process of developing a 630 MW combined cycle plant on the property where the retired Units 1 and 2 reside. See Regulatory Developments Regional Businesses Market Developments Western Region.

Encina. The Encina Station, of which NRG currently owns 50%, is located in Carlsbad, California and has a combined generating capacity of 965 MW from five fossil-fuel steam-electric generating units and one

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combustion turbine. The five fossil-fuel steam-electric units, which all primarily use natural gas (and oil for emergency backup only under a gas supply force majeure condition), provide intermediate load services. The combustion turbine only provides peaking services of 14 MW. Units 1, 2 and 3 each have a generation capacity of approximately 107 MW and were installed in 1954, 1956 and 1958, respectively. Units 4 and 5 have a generation capacity of approximately 300 MW and 330 MW respectively, and were installed in 1973 and 1978. The combustion turbine was installed in 1966. Units 1, 2 and 3 are projected to be retired after 2010. Low NO_x burner modifications and selective catalytic reduction equipment has been installed on Units 1, 2, 3, 4 and 5.

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. The potential improvement in earnings for 2006 is expected to be approximately $6 million over the projected budget, depending upon market conditions. In addition, El Segundo Units 3 and 4 have been contracted by a load serving entity for May 1, 2006 through April 30, 2008 for a capacity payment and tolling the purchaser s natural gas. The Cal ISO has indicated that load growth needs by 2007 may require the re-designation of Encina Unit 4 in 2007.

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. In January 2006, FERC approved an increase in the soft cap 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. See Regulatory Developments Regional Businesses Market Developments Western Region.

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OTHER

Other North American Assets

As of September 30, 2005, NRG owned approximately 1,470 MW of generating capacity in other regions 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
Other Assets				
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 a state of transition. The Audrain project is under contract for sale. Closing is expected in 2006. NRG is in advanced discussions regarding the transfer 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 subject to regulatory approval, and is expected to close in the first quarter of 2006. See Summary Recent Developments.

Australia and All Other Generation and Non-Generation Assets

As of September 30, 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 September 30, 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	98.7%	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, efficient and sustainable 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. NRG will seek to determine the best option, which may include a joint venture, equity spin-off, asset swap for U.S. generation assets or trade sale over the next few months.

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. The Gladstone assets are owned in partnership 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.

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 September 30, 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.

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 September 30, 2005, the combined company would have had 3,740 employees, approximately 1,751 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 the FERC, the 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 and RTO markets in which we participate.

The plant operations of, and wholesale electric sales from, Texas Genco 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, Texas Genco s 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, FERC determines whether a generation facility qualifies for Exempt Wholesale Generator, or EWG, status under 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. This permits NRG to own and operate these electric generating facilities without becoming subject to regulation as a holding company under PUHCA of 1935, and in the case of NRG s QFs, to make wholesale sales of electricity to electric utilities at the utility s avoided cost that are not subject to regulation by FERC. FERC s regulation of NRG under each of these statutes will be changed by the recent passage of the Energy Policy Act of 2005, or EPAct 2005.

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, provided certain market and transmission access conditions exist, and enacted the Public Utility Holding Company Act of 2005, or PUHCA of 2005. EPAct 2005 s PUHCA changes take effect 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 combined 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. With exceptions for certain small power production facilities (non-geothermal facilities greater than 30 MWs), QFs are currently exempt from the FERC s FPA rate regulation to the extent that sales made from them are made pursuant to the exemptions established under PURPA and are not made under a market-based or cost-based rate authorization from FERC. Currently, all of NRG s QF power sales are made pursuant to the PURPA established exemption or pursuant to FERC market-based rate authorization.

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, small power production QFs greater than 30 MWs 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 these 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, our market-based sales are subject to certain market behavior rules and, if any of our generating and 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 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. On October 28, 2005, NRG filed such a notice of change in status regarding the Texas Genco acquisition. No party has filed any comments in response to this change in status filing.

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.

In addition, 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 of the FERC.

Section 203 of the FPA also 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, as proposed to be implemented by FERC, certain companies proposing to acquire foreign utilities or foreign operating companies would be required to obtain prior FERC approval. This proposed implementation, if unchanged, could impede NRG s future acquisition of foreign assets. Also, depending on how the new law is interpreted, certain mergers or acquisitions involving holding companies owning generation assets only in Texas, which were formally exempt from FERC review under Section 203 of the FPA, may now be subject to such review under the EPAct 2005 amendments to the law. The provisions of EPAct 2005 relating to prior approval of asset acquisitions under the FPA become effective February 8, 2006.

PUHCA. As discussed above, EPAct 2005 repeals PUHCA of 1935, effective February 8, 2006, and replaces it with PUHCA of 2005.

PUHCA of 1935, among other things, provides for extensive regulation by the Securities and Exchange Commission, or SEC, of non-exempt public utility holding companies, limits their utility operations to a

single, integrated utility system and requires divestiture of operations not functionally related to the operation of the utility system. PUHCA of 1935 applies to foreign utility operations unless such operations qualify as a Foreign Utility Company, or FUCO or EWG, as defined under the act.

PUHCA of 2005 retains certain definitions from PUHCA of 1935 (such as the definitions of EWG and FUCO) and 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 or FUCOs. Because all of Texas Genco s and NRG s generating facilities have QF status or are owned through EWGs or FUCOs, neither company currently qualifies as a holding company under PUHCA of 1935 or PUHCA of 2005.

Public Utility Regulatory Policies Act. PURPA was initially 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 termination of the obligation to purchase power from QFs at an avoided cost rate under certain conditions. However, the purchase obligation is only terminated 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). Certain of NRG s QFs currently interconnect into markets that may meet the qualifications for elimination of the PURPA purchase requirement. If the obligation of the local utility 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. In addition, under proposed FERC rules 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, Texas Genco, LP is an NRC licensee and is subject to NRC regulation. Texas Genco, LP s 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. Texas Genco, LP owns a related interest in 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 will remain in effect after closing of the Acquisition.

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.

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 Texas Genco s 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 Texas Genco s 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 Texas Genco s 44.0% share, provided that Texas Genco has 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

Texas Genco s 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 independent system operators, or regional transmission organizations, or ISOs or RTOs. Most of these ISOs or RTOs administer a wholesale centralized bid-based spot market in their regions pursuant to tariffs approved by FERC and associated ISO/ RTO 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 or RTOs 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. Except for sales within ERCOT and by certain of NRG s QFs under PURPA, all of NRG s sales, whether made into an ISO- or RTO-administered market or bilaterally negotiated, are made pursuant to market-based rate authorizations granted by FERC to our FPA public utility subsidiaries. Access to, pricing for and operation of the transmission grid in regions not controlled by such ISOs or RTOs is controlled by the local transmission owning utility according to its Open Access Transmission Tariff approved by FERC.

Both Texas Genco and NRG are affected by rule/tariff changes that occur in the existing ISOs and RTOs. The ISOs and RTOs 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, the regulatory and legislative changes that have recently been enacted 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.

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 the parties will conclude January 27, 2006.

Northeast Region

RMR Agreements

During 2005, NRG s Devon, Middleton and Montville stations operated under RMR agreements with ISO-NE. With these RMR agreements set to expire at the end of 2005, on November 1, 2005, NRG filed new RMR agreements with FERC in order provide for the continued provision of reliability services from these resources. Following the filing of interventions and protests challenging the proposed rates and provisions of the filed RMR agreements, NRG entered into a settlement agreement with the Connecticut Department of Public Utility Control, the Connecticut Office of Consumer Counsel, and ISO-NE. This settlement agreement was filed as an Offer of Settlement, or Settlement, with FERC on December 20, 2005, in Docket No. ER06-118-000. NRG is not aware of any opposition to the Settlement and has requested FERC approve the settlement by January 31, 2006.

Under the settlement, NRG is entitled to annual fixed revenue requirement of $98 million, allocated among the stations, subject to NRG meeting the availability requirements specified therein. In addition, NRG is also entitled to retain 35% of its market revenues from the subject stations, while crediting 65% of such revenues against the monthly availability payments under the RMR agreements. The settlement will allow NRG to maintain uninterrupted RMR service from its stations, without the regulatory litigation that Connecticut entities are pursuing against other RMR applicants. The settlement specifies a January 1, 2006 effective date and the parties have requested expedited approval of the settlement RMR agreements without modification. Pending FERC s determination on the settlement, the ISO-NE has agreed to implement the settlement RMR agreements effective January 1, 2006. As part of the settlement, NRG and ISO-NE agreed on appropriate revisions to some of the operating characteristics, bid costs and operating characteristics, and with those changes, all of ISO-NE s concerns with the November 1, 2005 filing have been resolved.

The new RMR agreements will be in effect until LICAP is fully implemented or as FERC may otherwise determine if it approves a transition program for LICAP. In addition, the settlement RMR agreements contain some new termination provisions. For example, the Devon RMR agreement will terminate ninety days after the commencement of Locational Forward Reserve Market, but no earlier than January 1, 2007. In certain circumstances, after January 1, 2007, the Connecticut entities will be allowed to seek termination by filing a Section 206 complaint at FERC.

LICAP Market Developments

On August 31, 2004, ISO-NE filed its proposal for LICAP with the FERC, which is deciding the issue in a litigated proceeding before an administrative law judge. Under the proposal, separate capacity markets would be created for distinct areas of New England, including southwest Connecticut, where several of NRG s Connecticut plants are located, and the rest of the state of Connecticut. While NRG views this proposal as a

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positive development, as it is currently proposed it would not permit NRG to recover all of its fixed costs. In response, NRG has submitted testimony that includes an alternative proposal. On June 15, 2005, the FERC administrative law judge issued her recommended decision, which recommended FERC approve ISO-NE s proposed LICAP design with few exceptions. On July 15, 2005, NRG and the other parties to the case filed briefs on exceptions to the decision with FERC. On August 10, 2005, FERC issued an order delaying the implementation of a LICAP market from January 1, 2006 until October 1, 2006, at the earliest, and conducted oral argument on September 20, 2005. On October 7, 2005, participants in NEPOOL filed a joint motion with the FERC for the expedited appointment of a settlement judge and the commencement of settlement negotiations regarding the establishment of a LICAP market. On October 12, 2005, in response to a motion filed by ISO-NE for clarification of the FERC s order of August 10, 2005 delaying implementation of the LICAP market, the FERC delayed the implementation of a separate energy zone for southwest Connecticut.

Connecticut

On September 12, 2005, Richard Blumenthal, Attorney General for the state of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative and the Connecticut Industrial Energy Consumers filed a complaint against ISO-NE pursuant to sections 206 and 212 of the Federal Power Act, seeking to amend the ISO-NE s Market Rule 1 to require all electric generation facilities not currently operating under an RMR agreement in Connecticut to be placed under cost-of-service rates. On October 20, 2005, NRG, among others, filed an answer requesting that the Commission dismiss the complaint. NRG s Jet Power and Norwalk facilities are not currently operating under an RMR agreement.

New York

NRG s New York City generation is presently subject to price mitigation in the installed capacity market. When the capacity market is tight, the price NRG receives is capped by the mitigation price. However when the New York City capacity market is not tight, such as during the winter season, the proposed demand curve price levels should increase revenues from capacity sales over revenues obtained in previous capacity markets. On January 7, 2005, NYISO filed proposed installed capacity, or ICAP, demand curves for the following capacity years: 2005-06, 2006-07 and 2007-08. Under the NYISO proposal, the ICAP price for New York City generation would be $126 per KW-year for the capacity year 2006-07. On April 21, 2005, FERC accepted the NYISO s proposed demand curves, with certain minor revisions. The existing in-city mitigation measures, however, will continue to apply to us when the capacity market is tight, preventing us from obtaining these higher prices.

On October 6, 2005, Niagara Mohawk Power Corporation, or NiMo, filed a complaint against NYISO and the New York State Reliability Council, or NYSRC, requesting that the FERC direct the NYSRC to modify its methodology for calculating the statewide installed reserve margin. NiMo s complaint also alleges that the NYISO incorrectly calculates the installed capacity requirement.

Mid Atlantic

On January 25, 2005, FERC issued an order approving the PJM Interconnection, L.L.C., or PJM, proposal to increase the compensation for generators that are located in load pockets and are mitigated at least 80% of their running time. Specifically, when a generator would be subject to mitigation, the generator would have the option of recovering its variable cost plus $40 or a negotiated rate with PJM based on the facility s going forward costs. If the generator declines both options, it could file for an alternative rate with FERC. FERC also substantially revised the exemption of facilities built after 1996 from the energy price capping mitigation rule. Several of NRG s facilities are presently mitigated 80% of the time and, therefore, are impacted by the change and may benefit from the increased compensation provided for such generators.

On August 31, 2005, PJM filed a proposed reliability pricing model, or RPM, that, if accepted by FERC, would modify the capacity obligations imposed on load, and related market mechanisms within PJM. The primary features of the RPM proposal are the establishment of locational capacity markets using a downward-sloping demand curve similar to the demand curve model adopted in New York; a four-year-forward commitment of capacity resources; establishing separate obligations and auction procurement mechanisms for quick start and load following resources; allowing certain planned resources, transmission upgrades and

demand resources to compete with existing generation resources to satisfy capacity requirements; and market power mitigation rules (which are primarily applied to existing generation resources, such as NRG s). On October 19, 2005, NRG filed an intervention and protest in response to the PJM RPM proposal. On December 8, 2005, FERC issued a notice establishing a technical conference on the issues raised by PJM s RPM filing. The outcome of this proceeding is not possible to predict with certainty, nor is the timing of any implementation of PJM s proposed RPM model.

South Central Region

On January 3, 2005, Entergy submitted a petition for declaratory order requesting guidance on issues associated with its proposal to establish an independent coordinator of transmission, or ICT. Entergy requested FERC s guidance on whether the functions to be performed by the ICT will cause it to become a public utility under the Federal Power Act or the transmission provider under Entergy s Open Access Transmission Tariff, or OATT, and whether Entergy s transmission pricing proposal satisfies FERC s transmission pricing policy. On May 23, 2005, FERC issued an order granting rehearing for further consideration but has not yet acted on rehearing.

On March 22, 2005, FERC granted Entergy s Petition for declaratory order, stating that the implementation of the ICT proposal on an experimental basis will permit a transmission decision-making process that is independent of control by any market participant or class of participants. On May 27, 2005, Entergy submitted a Section 205 filing detailing the enhanced functions that the ICT will perform. Numerous interventions and protests were filed in response, a technical conference has been held and the proceeding is ongoing.

Western Region

NRG has negotiated RMR agreements with the Cal ISO for one-year terms for all of the WCP capacity. NRG has filed these RMR agreements with FERC, with an effective date of January 1, 2006, for each of our Encina and Cabrillo II plants. Cal ISO did not designate the El Segundo plant as an RMR for 2006. A tolling agreement for the total capacity of the El Segundo plant has been executed with a major load serving entity for the period May 2006 through April 2008.

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 $1.0 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

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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. 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. 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.

Environmental Matters

NRG and Texas Genco 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 or Texas Genco 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, Pennsylvania, 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 or 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.

Since 1999, Texas Genco has 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 to attain the one-hour national ambient air quality standard for ozone, as well as provisions of the Texas electric restructuring law. As a result, emissions from its plants in the Houston-Galveston area have been reduced by approximately 88% from 1998 levels and its fleet overall operates at one of the lowest NO_x emissions rates in the country. In aggregate, the Texas Genco 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 Texas Commission on Environmental Quality

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 Texas Genco 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 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 U.S. 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, 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. The proposed change is subject to public comment through February 17, 2006.

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

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

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended, the state of Texas is required to provide, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the state. The state of Texas has agreed to a compact with the 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 Texas Genco s 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 January 3, 2006, Texas Genco 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. NRG s Somerset plant is subject to these regulations. NRG has installed natural gas reburn technology to meet the NO_x and SO_2 limits. On June 4, 2004, the Massachusetts Department of

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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 NRG s 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 which could allow the use of on-site and off-site generated CO_2 credits, with a price backstop of $10/ton. Comments are due by the end of January 2006 and 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.

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 is to generate 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 voluntary 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 $1.3 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 will actively participate 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 debate by state agencies and industry, if 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 offtakers), allowing 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. While this policy statement does not impose new requirements at this time, instead requiring CPUC staff to investigate possible new requirements that would apply to all IOU procured energy and capacity, including in and out-of-state generation, it gives some basis for expecting the development of carbon constrained standards within the California wholesale power market.

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. Although both NRG and Texas Genco have been involved in on-site contamination matters, to date, neither has 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 has accrued $10 million related to the mine reclamation obligation.

Northeast Region. Significant amounts of ash are contained in landfills at on and off-site locations. At Dunkirk, Huntley, Somerset and Indian River, ash is disposed of at landfills owned and operated by NRG. NRG maintains financial assurance to cover costs associated with landfill closure, post-closure care and monitoring activities. NRG has funded a trust in the amount of approximately $6.0 million to provide such financial assurance in New York and $6.9 million in Delaware. NRG must also maintain financial assurance

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for closing interim status RCRA (Resource Conservation and Recovery Act) facilities at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations and has funded a trust in the amount of $1.5 million accordingly.

NRG inherited historical clean-up liabilities when it acquired the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. During installation of a sound wall at Somerset Station in 2003, oil contaminated soil was encountered. NRG has delineated the general extent of contamination, determined it to be minimal, and has placed an activity use limitation on that section of the property. Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified. NRG has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical ash contamination at the facilities. The total estimated cost is not expected to exceed $1.5 million. Remedial obligations at the Arthur Kill generating station have been established in discussions between NRG and the NYSDEC and are estimated to be approximately $1.1 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be approximately $2.9 million. While installing groundwater-monitoring wells at Astoria to track our remediation of an historical fuel oil spill, the drilling contractor encountered deposits of coal tar in two borings. NRG reported the coal tar discovery to the NYSDEC in 2003 and delineated the extent of this contamination. NRG may also be required to remediate the coal tar contamination and/or record a deed restriction on the property if significant contamination is to remain in place.

In September 2001, we experienced an underground fuel line leak at our Vienna Generating Station, resulting in a small release of oil free product, which was contained. NRG promptly reported the event to the relevant state agencies and continues to work with the Maryland Department of the Environment, or DEP, to develop any remediation requirements. Ongoing monitoring has indicated that the product is stable. NRG submitted a site assessment report and proposed remediation plan to Maryland DEP but the agency has not formally responded to those documents. Based upon work completed by a remediation contractor retained by NRG, long-term clean up liability in connection with this matter is not expected to exceed $0.5 million.

South Central Region. Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by NRG in the amount of approximately $5.0 million. Annual payments are made to the fund in the amount of $0.12 million.

Western Region. The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that SCE and San Diego Gas & Electric or SDG&E, as sellers retain liability, and indemnify NRG, for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. NRG and its business partner identified existing contamination and provided the results to the sellers. SCE and SDG&E agreed to address this identified contamination and are undertaking corrective action at the Encina and San Diego gas turbine generating sites. NRG could incur related costs if SCE and SDG&E did not complete their corrective action responsibilities. Spills and releases of various substances have occurred at these sites since NRG established the historical baseline, all of which have been, or will be, completely remediated. An oil leak in 2002 from underground piping at the El Segundo Generating Station contaminated soils adjacent to and underneath the Unit 1 and 2 powerhouse. NRG excavated and disposed of contaminated soils to the greatest extent permitted by existing laws. Following NRG s formal request, the Los Angeles Regional Water Quality Control Board agreed to allow the remaining contaminated soils to stay underneath the building foundation until the building is demolished.

A diesel fuel spill to on-site surface containment occurred at the Cabrillo Power II LLC Kearny Combustion Turbine facility (San Diego) in February 2003. Emergency response and subsequent remediation activities were completed. Confirmation sampling for the site was completed in 2004 and submitted to the San Diego County Department of Environmental Health. Three San Diego Combustion Turbine facilities, formerly operating pursuant to land leases with the U.S. Navy, are currently being decommissioned with equipment being removed from the sites and remediation activities occurring where necessary. All remedial

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activities are being completed pursuant to the requirements of the U.S. Navy and the San Diego County Department of Environmental Health. Remediation activities were completed in 2004 at the Naval Training Center and North Island facilities. At the 32nd Street Naval Station facility, additional contamination delineation is necessary and additional unquantified remediation in inaccessible areas may be required in the future. Given the current uncertainties at this facility, it is difficult to accurately estimate the resultant clean up liability.

International Environmental Matters

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

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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.

Insurance

General

Both NRG and Texas Genco carry insurance coverage consistent with companies engaged in similar commercial operations with similar properties, including business interruption insurance for the coal and lignite plants. However, both NRG s and Texas Genco 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.

We expect to receive a report from Moore-McNeil LLC, an internationally recognized independent insurance consulting firm, which concludes that the insurance program that is presently in effect for NRG and Texas Genco is consistent with prudent industry practice.

Nuclear

Texas Genco 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 $3,500,000 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. By the date of closing of the Acquisition, Texas Genco would have also purchased additional accidental outage coverage for its ownership percentage in STP. This coverage will provide maximum weekly indemnity of $1,980,000 for 52 weeks and $1,584,000 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, Texas Genco 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.

Legal Proceedings

We are, from time to time, a party to litigation or legal proceedings arising in the ordinary course of our business, most of which involves contract disputes or claims for personal injury, including exposure to asbestos and property damage incurred in connection with our operations. We believe that we have valid defenses to the legal proceedings and investigations described below and we intend 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 us or our subsidiaries in the future, asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified below, we are unable to predict the outcome of these legal proceedings. An unfavorable outcome in one or more of these proceedings could have a material impact on our consolidated financial position, results of operations or cash flows. We also have indemnity rights for some of these proceedings to reimburse us for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

Texas Commercial Energy Litigation

In July 2003, Texas Commercial Energy filed in federal court in Corpus Christi, Texas a lawsuit against, as the lawsuit was subsequently amended, Texas Genco, LP, CenterPoint Energy, Inc., Reliant Energy, Inc., Reliant Electric Solutions, LLC, several other CenterPoint Energy, Inc. and Reliant Energy, Inc. 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 federal court dismissed plaintiff s claims on jurisdictional grounds and, in July 2004, the plaintiff filed an appeal that Texas Genco, LP contested. The court of appeals 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, plaintiff s petition for certiorari to the U.S. Supreme Court was denied.

The Valence Litigation

On February 20, 2004, Texas Genco, LP filed an injunction and declaratory judgment lawsuit in a Freestone County, Texas state district court seeking to enjoin Valence Operating Company, or Valence, from drilling or engaging in work to prepare for drilling a natural gas well (Well 8) in Texas Genco, L.P. s Class II Industrial Solid Waste Facility, which we refer to as the Landfill, adjacent to Texas Genco s Limestone Plant. The Landfill is used to dispose of ash byproducts from the combustion of coal and lignite at the Limestone Plant. Following a hearing in March 2004, the court granted Texas Genco, LP s request and enjoined Valence from drilling the well in the Landfill. In connection with that injunction, the court ordered, and Texas Genco, LP posted, a bond in the amount of $1.0 million to secure payment of any damages suffered by Valence should it be found to have been wrongfully enjoined. Valence filed a counter-claim against Texas Genco, LP for wrongful injunction and sought to recover the full amount of the bond. Trial on the merits in this case was held in November 22, 2004. The jury found, among other things, that Texas Genco, LP had an existing use that would be precluded or substantially impaired if Valence drilled Well 8. The jury also found damages in the amount of $400,000 as compensation to Valence for the issuance of the temporary restraining order and temporary injunction. Both Texas Genco, LP and Valence moved to disregard certain of the jury s findings and for judgment in their respective favors. On October 24, 2004, the court accepted the jury s findings and entered judgment that Texas Genco, LP take nothing on its claim for permanent injunction, and that Valence recover $400,000 in damages, together with pre- and post-judgment interest and costs. The court also reinstated the temporary injunction pending resolution of Texas Genco, LP s appeal and also ordered, and Texas Genco posted, a bond in the amount of approximately $860,000 in connection with the temporary injunction. The bond shall be increased on a monthly basis after February 2006. Texas Genco, LP filed a timely appeal to the Waco County Court of Appeals. On January 18, 2006, the court reversed the trial court s decision ordering that Valence take nothing on its counterclaim and remanding the case back to the trial court for entry of a permanent injunction enjoining Valence from drilling Well 8.

In addition, a separate lawsuit was filed by Texas Genco, LP in the same court, to enjoin Valence from drilling another well (Well 9) in the Landfill. On October 26, 2004, Texas Genco, LP also obtained a temporary restraining order against drilling this other well. The court ordered, and Texas Genco, LP posted, a

bond in the amount of approximately $2.0 million to secure payment of any damages suffered by Valence should it be found to have been wrongfully enjoined in this second lawsuit. The court recently increased the bond amount to $2.8 million, and has rescheduled this case to February 6, 2006 for trial on the merits.

Valence currently has two active applications with the Railroad Commission of Texas for drilling permits for two additional wells that would be drilled in the Landfill, one of which would be drilled through the closed cells in Texas Genco, LP s Landfill. Texas Genco, LP has filed a protest with the Railroad Commission of Texas over these applications, and a hearing was held at the Railroad Commission in April 2005. The hearing examiners recommended denying the permit for one well and granting the other. A ruling by the Railroad Commission is expected in the next few weeks. Texas Genco, LP is vigorously contesting these attempts to drill into the Landfill because such drilling activity impairs Texas Genco, LP s use of its property for the Landfill.

Texas Genco Asbestos Litigation

The Texas Genco plants are the subject of a number of lawsuits filed against numerous defendants in addition to Texas Genco Holdings, Inc., by a large number of individuals who claim personal injury due to alleged exposure to asbestos while working at plant sites in Texas. Most of these claimants have been third party contractor or sub-contractor employees 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 Texas Genco s plants, some of the claimants have worked at locations owned by Texas Genco. We anticipate that additional claims like those that have been asserted to date may be asserted in the future. Texas Genco defends these claims aggressively, and, thus, has incurred and expects to continue to incur defense costs as a result of such claims. In addition, while Texas Genco has been dismissed from many of these lawsuits without having to make any payment to claimants, it has incurred and expects to continue to incur some costs associated with the settlement of certain claims. Texas Genco intends to continue its practice of vigorously contesting claims that it does not consider to have merit. To date, costs of settlement and defense have not materially affected Texas Genco, and a portion of the payments in respect of these claims have been offset by insurance recoveries.

The Texas legislature recently adopted amendments to state law that 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. This new legislation, which was signed into law by the Governor of Texas on May 19, 2005, 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 that confirms that the claimant has met the standards for an actual physical impairment caused by exposure to asbestos, as specified in the legislation. This amendment to state law resulted in some increased claim activity prior to September 1, 2005, but after that date is expected to result in fewer new claims and overall lower costs of defending and settling claims not adjudicated by that date. As of December 31, 2005, there were 3,803 claims pending against Texas Genco Holdings, Inc., a wholly-owned subsidiary of Texas Genco LLC. For the twelve months ended December 31, 2005, there were 268 claims filed against Texas Genco Holdings, Inc., 146 claims settled, 1,261 claims dismissed or otherwise resolved with no payment and the average settlement amount for each claim was approximately $3,600 Under the terms of the separation agreement between Texas Genco Holdings, Inc. and CenterPoint Energy, ultimate financial responsibility for uninsured losses relating to such claims has been assumed by Texas Genco Holdings, Inc., and under the terms of CenterPoint Energy s agreement to sell Texas Genco Holdings, Inc. to Texas Genco LLC, 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 Texas Genco LLC.

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, payments made by us would not be offset by any insurance recoveries. The proposed legislation remains subject to negotiation and modification.

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California Wholesale Electricity Litigation and Related Investigations

NRG, WCP, WCP s four operating subsidiaries, Dynegy, Inc. and numerous other unrelated parties are the subject of numerous lawsuits arising based on events occurring in the California power market. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market gaming activities. Certain of these lawsuits originally commenced in 2000 and 2001, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Southern District of California. In December 2002, the district court found that federal jurisdiction was absent and remanded the cases back to state court. On December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the district court in most respects. On March 3, 2005, the Ninth Circuit denied a motion for rehearing. On May 5, 2005, the case was remanded to California state court and, under a scheduling order, defendants filed their objections to the pleadings. On July 22, 2005, based upon the filed rate doctrine and federal preemption, the court dismissed NRG Energy, Inc. without prejudice, leaving only subsidiaries of WCP remaining in the case. On October 3, 2005, the court sustained defendants demurrer dismissing the case against all remaining defendants. On December 2, 2005, the plaintiffs filed their notice of appeal from the dismissal.

In 2002, a number of cases similar to those described above were filed against defendants, including WCP or one or more of its operating subsidiaries and/or Dynegy, Inc., which we refer to as the Northern California cases. On February 25, 2005, the Ninth Circuit affirmed the district court s decision to dismiss all of the defendants Northern California cases. No appeal was taken from this decision.

In addition to the cases discussed above, other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers that name NRG and/or WCP and/or certain subsidiaries of WCP, in addition to numerous other defendants. The complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California s antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys fees and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several of these proceedings. In the above referenced cases relating to natural gas, Dynegy is defending WCP and/or its subsidiaries pursuant to an indemnification agreement and will be the responsible party for any loss. In cases relating to electricity, Dynegy s counsel is representing it and WCP and/or its subsidiaries with each party responsible for half of the costs and each party shall be responsible for half of any loss. Where NRG is named as a party in an electricity case, it is defending the case and bears its own costs of defense.

FERC Proceedings

There are proceedings in which WCP and WCP subsidiaries are parties, which either are 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 Cal ISO, the California Department of Water Resources, or CDWR, and the State of California. 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 revenues collected from CDWR. In 2003, FERC rejected this demand and denied rehearing. The case was appealed to the U.S. Court of Appeals for the Ninth Circuit where oral argument was held December 8, 2004.

California Attorney General

The California Attorney General has undertaken an investigation entitled In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California. Dynegy, NRG and subsidiaries of WCP have responded to interrogatories, document requests and to requests for interviews.

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Canadian Claim

On June 30, 2005, three individuals filed a lawsuit with the Ontario Superior Court of Justice against more than 20 power generating entities in the U.S. and Canada, including the Keystone and Conemaugh facility ownership groups. Two of NRG s subsidiaries own less than four percent of each of these Pennsylvania coal-fired plants. The plaintiffs, on behalf of a purported class of Ontario residents, have alleged air pollution and associated health effects and asserted damages in excess of CA$50 billion (US $43.1 billion, based on conversion rates as of September 30, 2005). The claim was not served on any defendant by December 30, 2005. Accordingly, the claim is inactive and may be revived only if plaintiffs file a motion to extend the time for service and the court grants the motion. Alternatively, plaintiffs could seek to file a new claim.

New York Operating Reserve Markets

Consolidated Edison and others petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of FERC s refusal to order a re-determination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for a two month period in 2000. On November 7, 2003, the court found that NYISO s method of pricing spinning reserves violated the NYISO tariff. On March 4, 2005, FERC issued an order favorable to NRG 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 authority to revise the prices in this market. A motion for rehearing of the order was filed before the April 3, 2005 deadline and on November 17, 2005, FERC denied rehearing. On January 13, 2006, the petitioners filed an appeal with the U.S. Court of Appeals for the District of Columbia Circuit.

Connecticut Congestion Charges

On November 28, 2001, Connecticut Light & Power, or CL&P, sought recovery in the U.S. District Court for Connecticut for amounts it claimed were owed for congestion charges under the October 29, 1999 Standard Offer Services Contract. CL&P withheld approximately $30 million from amounts owed to PMI under contract and PMI counterclaimed. CL&P s motion for summary judgment, which PMI opposed, remains pending. We cannot estimate at this time the overall exposure for congestion charges for the term of the contract prior to the implementation of standard market design, whi