NRG ENERGY, INC.
Form 10-K
February 28, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

x	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the Fiscal Year ended December 31, 2013.
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the Transition period from to .

Commission file No. 001-15891

NRG Energy, Inc.
(Exact name of registrant as specified in its charter)

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

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

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $7,506,455,756 based on the closing sale price of $26.70 as reported on the New York Stock Exchange.

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

Class	Outstanding at February 26, 2014
Common Stock, par value $0.01 per share	325,217,179

Documents Incorporated by Reference:

Portions of the Registrant's definitive Proxy Statement relating to its 2014 Annual Meeting of Stockholders are incorporated by reference into Part III of this Annual Report on Form 10-K

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Glossary of Terms

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

2012 Form 10-K	NRG's Annual Report on Form 10-K for the year ended December 31, 2012
316(b) Rule	Regulations promulgated by the EPA to implement a section of the Clean Water Act regulating cooling water intake structures
ARO	Asset Retirement Obligation
ARRA	American Recovery and Reinvestment Act
ASC	The FASB Accounting Standards Codification, which the FASB established as the source of authoritative U.S. GAAP
ASU	Accounting Standards Updates – updates to the ASC
AZNMSN	Arizona, New Mexico and Southern Nevada
BACT	Best Available Control Technology
Baseload	Units expected to satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
Capital Allocation Program	NRG's plan of allocating capital between debt reduction, reinvestment in the business, investment in acquisition opportunities, share repurchases and shareholder dividends
CCS-EOR	Carbon Capture and Sequestration with Enhanced Oil Recovery project
CDWR	California Department of Water Resources
C&I	Commercial, industrial and governmental/institutional
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
Distributed Solar	Solar power projects, typically less than 20 MW in size, that primarily sell power produced to customers for usage on site, or are interconnected to sell power into the local distribution grid
DNREC	Delaware Department of Natural Resources and Environmental Control
DSU	Deferred Stock Unit
EME	Edison Mission Energy
Energy Plus Holdings	Energy Plus Holdings LLC
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement and Construction
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESEC	El Segundo Energy Center LLC
ESPP	Employee Stock Purchase Plan
EWG	Exempt Wholesale Generator
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
FPA	Federal Power Act

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FRCC	Florida Reliability Coordinating Council
Fresh Start	Reporting requirements as defined by ASC-852, Reorganizations
GenOn	GenOn Energy, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC
GenOn Americas Generation Senior Notes	GenOn Americas Generation's $850 million outstanding unsecured senior notes consisting of $450 million of 8.5% senior notes due 2021 and $400 million of 9.125% senior notes due 2031
GenOn Mid-Atlantic	GenOn Mid-Atlantic, LLC and, except where the context indicates otherwise, its subsidiaries, which include the coal generation units at two generating facilities under operating leases
GenOn Senior Notes	GenOn's $2.0 billion outstanding unsecured senior notes consisting of $725 million of 7.875% senior notes due 2017, $675 million of 9.5% senior notes due 2018, and $550 million of 9.875% senior notes due 2020 ($575 million of 7.625% senior notes due 2014 were redeemed in June of 2013)
GenOn Holdings	GenOn Energy Holdings, Inc.
GHG	Greenhouse Gases
Green Mountain Energy	Green Mountain Energy Company
GWh	Gigawatt hour
Heat Rate	A measure of thermal efficiency computed by dividing the total BTU content of the fuel burned by the resulting kWh's generated. Heat rates can be expressed as either gross or net heat rates, depending whether the electricity output measured is gross or net generation and is generally expressed as BTU per net kWh
High Desert	TA - High Desert, LLC
High Desert Facility	High Desert's $82 million non-recourse project level financing facility under the Note Purchase and Private Shelf Agreement
ISO	Independent System Operator, also referred to as Regional Transmission Organizations, or RTO
ISO-NE	ISO New England Inc.
Kansas South	NRG Solar Kansas South LLC
kWh	Kilowatt-hours
LIBOR	London Inter-Bank Offered Rate
LTIPs	Collectively, the NRG Long-Term Incentive Plan and the NRG GenOn Long-Term Incentive Plan
Marsh Landing	NRG Marsh Landing, LLC (formerly known as GenOn Marsh Landing, LLC)
Mass	Residential and small business
MATS	Mercury and Air Toxics Standards promulgated by the EPA
MD PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
Merger	The merger completed on December 14, 2012 by NRG and GenOn pursuant to the Merger Agreement
Merger Agreement	The agreement by and among NRG, GenOn Energy, Inc. and Plus Merger Corporation, dated as of July 20, 2012
Merit Order	A term used for the ranking of power stations in order of ascending marginal cost
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MOPR	Minimum Offer Price Rule
MSU	Market Stock Unit
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours

MWt	Megawatts Thermal Equivalent
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation

Net Capacity Factor	The net amount of electricity that a generating unit produces over a period of time divided by the net amount of electricity it could have produced if it had run at full power over that time period. The net amount of electricity produced is the total amount of electricity generated minus the amount of electricity used during generation
Net Exposure	Counterparty credit exposure to NRG, net of collateral
Net Generation	The net amount of electricity produced, expressed in kWhs or MWhs, that is the total amount of electricity generated (gross) minus the amount of electricity used during generation.
NINA	Nuclear Innovation North America LLC
NJDEP	New Jersey Department of Environmental Protection
NO_x	Nitrogen oxide
NOL	Net Operating Loss
NOV	Notice of Violation
NPNS	Normal Purchase Normal Sale
NQSO	Non-Qualified Stock Option
NRC	U.S. Nuclear Regulatory Commission
NRG GenOn LTIP	NRG 2010 Stock Plan for GenOn Employees (formerly the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, which was assumed by NRG in connection with the Merger)
NRG LTIP	NRG Long-Term Incentive Plan
NRG Yield	Reporting segment including the following projects: Alpine, Avenal, Avra Valley, AZ DG Solar, Blythe, Borrego, CVSR, GenConn, Marsh Landing, PFMG DG Solar, Roadrunner, South Trent and Thermal.
NRG Yield, Inc.	NRG Yield, Inc., the owner of 34.5% of NRG Yield LLC with a controlling interest, and issuer of publicly held shares of Class A common stock
NRG Yield LLC	NRG Yield LLC, which owns, through its wholly owned subsidiary, NRG Yield Operating LLC, all of the assets contributed to NRG Yield LLC in connection with the initial public offering of Class A common stock of NRG Yield, Inc.
NSPS	New Source Performance Standards
NSR	New Source Review
NYISO	New York Independent System Operator
NYSPSC	New York State Public Service Commission
OCI	Other comprehensive income
PADEP	Pennsylvania Department of Environmental Protection
Peaking	Units expected to satisfy demand requirements during the periods of greatest or peak load on the system
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PU	Performance Unit
PUCT	Public Utility Commission of Texas
PUHCA of 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility under PURPA
RCRA	Resource Conservation and Recovery Act of 1976
Reliant Energy	Reliant Energy Retail Services, LLC
Repowering	Technologies utilized to replace, rebuild, or redevelop major portions of an existing electrical generating facility, not only to achieve a substantial emissions reduction, but also to increase facility capacity, and improve system efficiency
Retail Business	

	NRG's retail energy brands, including Reliant, Green Mountain, Energy Plus and NRG Residential Solutions
Revolving Credit Facility	The Company's $2.5 billion revolving credit facility due 2018, a component of the Senior Credit Facility

RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RPS	Renewable Portfolio Standards
RSS	Reliability Support Service
RSU	Restricted Stock Unit
Schkopau	Kraftwerk Schkopau Betriebsgesellschaft mbH
SEC	United States Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
Senior Credit Facility	NRG's senior secured facility, comprised of the Term Loan Facility and the Revolving Credit Facility
SIFMA	Securities Industry and Financial Markets Association
Senior Notes	The Company's $5.9 billion outstanding unsecured senior notes consisting of, $1.2 billion of 7.625% senior notes due 2018, $700 million of 8.5% senior notes due 2019, $800 million of 7.625% senior notes due 2019, $1.1 billion of 8.25% senior notes due 2020, $1.1 billion of 7.875% senior notes due 2021, and $990 million of 6.625% senior notes due 2023
SERC	Southeastern Electric Reliability Council/Entergy
SO_2	Sulfur dioxide
STP	South Texas Project Electric Generating Station Units 1 & 2 — nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest
STPNOC	South Texas Project Nuclear Operating Company
TEPCO	The Tokyo Electric Power Company of Japan, Inc.
Term Loan Facility	The Company's $2.0 billion term loan facility due 2018, a component of the Senior Credit Facility
Texas Genco	Texas Genco LLC, now referred to as the Company's Texas Region
Tonnes	Metric tonnes, which are units of mass or weight in the metric system each equal to 2,205lbs and are the global measurement for GHG
TSR	Total Shareholder Return
TWh	Terawatt hour
U.S.	United States of America
U.S. DOE	United States Department of Energy
U.S. GAAP	Accounting principles generally accepted in the United States
Utility Scale Solar	Solar power projects, typically 20 MW or greater in size, that are interconnected into the transmission or distribution grid to sell power at a wholesale level
VaR	Value at Risk
VIE	Variable Interest Entity
WCP	WCP (Generation) Holdings, Inc.
WECC	Western Electricity Coordinating Council

PART I

Item 1 — Business

General

NRG Energy, Inc., or NRG or the Company, is a competitive power and energy company that aspires to be a leader in the way residential, industrial and commercial consumers think about, use, produce and deliver energy and energy services in major competitive power markets in the United States. NRG engages in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; the transacting in and trading of fuel and transportation services and the direct sale of energy, services, and innovative, sustainable products to retail customers. The Company sells retail electric products and services under the name “NRG” and various brands owned by NRG. Finally, NRG aspires to be a clean energy leader and is focused on the deployment and commercialization of potentially transformative technologies, like electric vehicles, Distributed Solar and smart meter/home automation technology that collectively have the potential to fundamentally change the nature of the power industry, including a substantial change in the role of the national electric transmission grid and distribution system.

Wholesale Power Generation

NRG's generation facilities are primarily located in the United States and comprise generation facilities across the merit order. The sale of capacity and power from baseload and intermediate generation facilities accounts for a majority of the Company's generation revenues. In addition, NRG's generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products, and providing ancillary services to support system reliability.

Retail

The Retail Business provides energy and related services to residential, commercial and institutional customers primarily located in Texas and selected Northeast markets. Products and services range from system power to home services, to bundled products which combine system power with protection products, energy efficiency and renewable energy solutions. Based on metered locations, as of December 31, 2013, NRG's Retail Business served approximately 2.3 million residential, small business, commercial and industrial customers.

Alternative Energy

NRG's investment in, and development of, new technologies is focused on identifying significant commercial opportunities and creating a comparative advantage for the Company. The Company's development and investment initiatives are focused on Distributed Solar, solar thermal, solar photovoltaic and wind and also include other low-or no-GHG emitting energy generating sources, such as the fueling infrastructure for electric vehicle, or EV, ecosystems.

The map below shows the locations of NRG's U.S. power generation facilities as of December 31, 2013, (excluding Distributed Solar), both operating and under construction, as well as the states where NRG operates its Retail Business:

Effective June 2013, the Company's segment structure and its allocation of corporate expenses were updated to reflect how management currently makes financial decisions and allocates resources. The Company has recast data from prior periods to reflect this change in reportable segments to conform to the current year presentation. The Company's businesses are primarily segregated based on the Retail Business, conventional power generation, alternative energy businesses, NRG Yield, and corporate activities. Within NRG's conventional power generation, there are distinct components with separate operating results and management structures for the following geographical regions: Texas, East, South Central, West and Other, which includes international businesses and maintenance services. The Company's alternative energy segment includes solar and wind assets (excluding those in the NRG Yield segment), electric vehicle services and the carbon capture business. NRG Yield includes certain of the Company's contracted generation assets including three natural gas or dual-fired facilities, eight utility-scale solar and wind generation facilities, two portfolios of distributed solar facilities and thermal infrastructure assets.

The following table summarizes NRG's global generation portfolio as of December 31, 2013, by operating segment, which includes 88 fossil fuel and nuclear plants, eleven Utility Scale Solar facilities and four wind farms, as well as Distributed Solar facilities. Also included are one Utility Scale Solar facility and additional Distributed Solar facilities currently under construction. All Utility Scale Solar and Distributed Solar facilities are described in megawatts on an alternating current basis. MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the Company's owned or lease interest excluding capacity from inactive/mothballed units:

	Fossil Fuel, Nuclear, and Renewable (In MW)								
Generation Type	Texas	East	South Central	West	Alternative Energy	NRG Yield	Total Domestic	Other (Inter-national)	Total Global
Natural gas	5,917	7,651	3,817	6,779	—	843	25,007	—	25,007
Coal	4,193	6,879	1,496	—	—	—	12,568	605	13,173
Oil[(a)]	—	5,531	—	—	—	190	5,721	—	5,721
Nuclear	1,176	—	—	—	—	—	1,176	—	1,176
Wind	—	—	—	—	347	101	448	—	448
Utility Scale Solar	—	—	—	—	836	303	1,139	—	1,139
Distributed Solar	—	—	—	—	37	10	47	—	47
Total generation capacity	11,286	20,061	5,313	6,779	1,220	1,447	46,106	605	46,711
Capacity attributable to noncontrolling interest	—	—	—	—	(331)	(499)	(830)	—	(830)
Total net generation capacity	11,286	20,061	5,313	6,779	889	948	45,276	605	45,881
Under Construction									
Utility Scale Solar	—	—	—	—	26	—	26	—	26
Distributed Solar	—	—	—	—	6	—	6	—	6
Total under construction	—	—	—	—	32	—	32	—	32

(a) The NRG Yield operating segment consists of two dual-fuel (natural gas and oil) simple-cycle generation facilities.

In addition, the Company's thermal assets provide steam and chilled water capacity of approximately 1,374 MWt through its district energy business, 28 MWt of which is available under the right-to-use provision of the Chilled Water Service Agreement at NRG Energy Center Phoenix, AZ.

Initial Public Offering of NRG Yield, Inc.

The Company formed NRG Yield, Inc. primarily to own and operate a portfolio of contracted generation assets and thermal infrastructure assets that have historically been owned and/or operated by NRG and its subsidiaries. On July 22, 2013, NRG Yield, Inc. closed its initial public offering of 22,511,250 shares of Class A common stock at a price of $22 per share. Net proceeds to NRG Yield, Inc. from the sale of the Class A common stock were approximately $468 million, net of underwriting discounts and commissions of $27 million. The Company retained 42,738,250 shares of Class B common stock of NRG Yield, Inc. As a result, the Company owns a controlling interest in NRG Yield, Inc. and will consolidate this entity for financial reporting purposes. In addition, the Company retained a 65.5% interest in NRG Yield LLC. The initial public offering represented the sale of a 34.5% interest in NRG Yield LLC. NRG Yield LLC's initial assets consisted of three natural gas or dual-fired facilities, eight utility-scale solar and wind generation facilities, two portfolios of distributed solar facilities that collectively represent 1,324 net MW, and thermal infrastructure assets with an aggregate steam and chilled water capacity of 1,098 net MWt and electric generation capacity of 123 net MW. On December 31, 2013, NRG Yield LLC acquired Energy Systems, as described in Item 15 — Note 3, Business Acquisitions and Dispositions. The following table represents the structure of NRG Yield, Inc. after the initial public offering:

GenOn Acquisition

On December 14, 2012, NRG completed the Merger with GenOn in accordance with the Merger Agreement, with GenOn continuing as a wholly-owned subsidiary of NRG. The Company issued, as consideration for the Merger, 0.1216 shares of NRG common stock for each outstanding share of GenOn, including restricted stock units outstanding, on the acquisition date, totaling 93.9 million shares of NRG common stock, and approximately $1 million in cash for fractional shares. The Merger was accounted for as an acquisition, and NRG was deemed to have acquired GenOn for accounting purposes. Specifically, consolidated financial statements and financial and operational results of NRG include the results of the combined entities from December 15, 2012, unless indicated otherwise.

NRG's Business Strategy

The Company's business is focused on: (i) excellence in operating performance of its existing assets; (ii) serving the energy needs of end-use residential, commercial and industrial customers in competitive markets through multiple brands and channels with a variety of retail energy products and services differentiated by innovative features, premium service, sustainability, and loyalty/affinity programs; (iii) optimal hedging of generation assets and retail load operations; (iv) repowering of power generation assets at premium sites; (v) investing in, and deploying, alternative energy technologies both in its wholesale and, particularly, in and around its Retail Business and its customers; (vi) pursuing selective acquisitions, joint ventures, divestitures and investments; and (vii) engaging in a proactive capital allocation plan focused on achieving the regular return of and on stockholder capital within the dictates of prudent balance sheet management. Underlying each aspect of the Company’s business is the Company’s commitment to safety for its employees, customers and partners.

In addition, the Company, through its subsidiary, NRG Yield, Inc., is focused on enhancing value for its stockholders through: (i) providing a more competitive source of equity capital that would accelerate NRG's long-term growth and acquisition strategy and optimize NRG's capital structure; and (ii) highlighting the reduced market exposure associated with the contracted conventional and renewable generation and thermal infrastructure assets embedded with NRG's merchant portfolio.

The Company believes that the U.S. energy industry is going to be increasingly impacted by the long-term societal trend towards sustainability, which is both generational and irreversible. Moreover, it further believes the information technology-driven revolution, which has enabled greater and easier personal choice in other sectors of the consumer economy, will do the same in the U.S. energy sector over the years to come. Finally, NRG believes that the aging transmission and distribution infrastructure of the national grid is becoming increasingly inadequate in the face of the more extreme weather demands of the 21^{st} century. As a result, energy consumers are expected to have increasing personal control over whom they buy their energy from, how that energy is generated and used (including their ability to self-generate from their own primarily sustainable energy resources) and what environmental impact individual choices will have. The Company's initiatives in this area of future growth are focused on: (i) renewables, with a concentration in solar and wind development; (ii) electric vehicle ecosystems; (iii) customer-facing energy products and services, including smart energy services that give consumers individual energy insights, choices and convenience, a variety of renewable and energy efficiency products, and numerous loyalty and affinity options and tailored product and service bundles sold through unique retail sales channels; and (iv) construction of other forms of on-site clean power generation. The Company's advances in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in Item 1, Business - New and On-going Company Initiatives and Development Projects and in Management's Discussion and Analysis of Financial Condition and Results of Operations, New and On-going Company Initiatives and Development Projects, in this Form 10-K.

In summary, NRG's business strategy is intended to maximize stockholder value through the production and sale of safe, reliable and affordable power to its customers in the markets served by the Company, while aggressively positioning the Company to meet the market's increasing demand for sustainable and low carbon energy solutions individualized for the benefit of the end use energy consumer. This strategy is designed to enhance the Company's core business of competitive power generation and mitigate the risk of declining power prices. The Company is a leading provider of sustainable energy solutions that promote both consumer welfare and national energy security.

Competition

NRG competes in wholesale power generation, deregulated retail energy services and in the development of renewable and conventional energy resources. The Retail Business competes with national and international companies that operate in multiple geographic areas, as well as numerous companies that are regional or local in nature, and other competitors, typically incumbent retail electric providers, which have the advantage of long-standing relationships with customers.

Wholesale Power Generation

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. NRG competes on the basis of the location of its plants and ownership of portfolios of plants in various regions, which increases the stability and reliability of its energy revenues. Wholesale power generation is a regional business that is currently highly fragmented and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identities of the companies NRG competes with depending on the market. Competitors include regulated utilities, other independent power producers, and power marketers or trading companies, including those owned by financial institutions, municipalities and cooperatives.

Retail

The deregulated electricity markets across the nation provide an intensely competitive landscape for energy providers to sell products and services to all customer segments (residential, small business, commercial and industrial businesses, governments and other public institutions). The retail markets in which the Company competes include but are not limited to the following states: Connecticut, Delaware, Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Ohio, Oregon and Texas, as well as the District of Columbia. The ERCOT market in Texas is NRG's biggest retail market.

Retail customers make purchase decisions based on a variety of factors, including price, customer service, brand, product choices, bundles or value-added features. Customers purchase products through a variety of sales channels including direct sales force, call centers, websites, brokers and brick-and-mortar stores.

Development

NRG continuously evaluates opportunities for development of new generation, on both a merchant and contracted basis. Merchant development opportunities, at present, are more limited due to the volatile power markets and the prevailing low price of natural gas prompted by the shale gas revolution over the past several years. As such, the majority of NRG's current developments are in response to Requests For Proposals, or RFPs, for new conventional or renewable generation and/or generating capacity backed by contracts with credit-worthy counterparties. Many RFPs are solicited by regulated utilities or electric system operators, often to comply with mandated renewable portfolio standards or to achieve an improved reserve margin, which is a measure of a market's available electric power capacity over and above the electric power capacity needed to meet normal peak demand levels. NRG competes against other power plant developers and manufacturers of solar panel assemblies. The number and type of competitors vary based on the location, generation type, project size and counterparty specified in the RFP. Bids are awarded based on many factors including price, location of existing generation, prior experience developing generation resources similar to that specified in the RFP, and creditworthiness.

Competitive Strengths

Conventional Wholesale Power Generation

NRG has one of the largest and most diversified power generation portfolios in the United States, with approximately 44,472 MW of fossil fuel and nuclear generation capacity at 87 plants as of December 31, 2013. The Company's power generation assets are diversified by fuel-type, dispatch level and region, which helps mitigate the risks associated with fuel price volatility and market demand cycles.

NRG's U.S. baseload and intermediate facilities provide the Company with a significant source of cash flow, while its peaking facilities provide NRG with opportunities to capture upside potential that can arise during periods of high demand, which typically drive higher energy prices.

Many of NRG's generation assets are located within densely populated areas that tend to have more robust wholesale pricing as a result of relatively favorable local supply-demand balance. NRG now has generation assets located in or near Houston, New York City, Washington D.C., New Jersey, southwestern Connecticut, Pittsburgh, Cleveland, and the Los Angeles, San Diego, and San Francisco metropolitan areas. These facilities are often ideally situated for repowering or the addition of new capacity because their location and existing infrastructure give them significant advantages over undeveloped sites.

Retail

Through its Retail Business, in 2013, NRG delivered approximately 60 TWhs and had approximately 2.3 million customers as of December 31, 2013, making it the largest retailer in Texas and one of the largest retail energy providers in the United States. NRG's multi-brand Retail Business offers a broad range of services and value propositions that enable it to attract, retain, and increase the value of the Company's residential, small business and commercial and industrial customer relationships. With the largest market share in ERCOT based on volume sales, Reliant Energy, an NRG Company, is recognized for its exemplary customer service as well as its innovative smart energy and technology product offerings and home energy services. Green Mountain Energy is widely recognized as a pioneer in competitive retail energy markets and provides customers an environmentally friendly alternative for their energy supply requirements. Energy Plus, which is increasingly selling under the NRG brand name, has exclusive marketing arrangements with leading loyalty program providers and affinity group associations. Finally, NRG is selling renewables, home services, portable power and customized energy solutions to customers in the Company's chosen markets. Through the multi-brand Retail Business, NRG is able to provide its customers a broad range of energy services and products, including system power, smart energy services and energy efficiency services, electric vehicle services, protection products, distributed generation, solar and wind products, carbon management and specialty services. The breadth and scope of the Retail Business also creates opportunities for delivering value enhancing energy solutions to customers on a national level. In an industry that is subject to commodity price volatility, NRG expects that an expanded core generation fleet will enable the combined company to replicate in multiple markets, principally in the East, the successful integrated wholesale-retail business model that NRG currently operates in the Texas region.

Solar and Other Alternative Energy Technologies

NRG is one of the largest solar power developers and owner-operators in the United States, having demonstrated the ability to develop, construct and finance a full range of solar energy solutions for utilities, schools, municipalities, commercial and residential market segments. The Company has 1,666 MW of renewable generation capacity, of which 1,634 MW is operational and 32 MW is under construction as of December 31, 2013, comprised of ownership interests in four wind farms, eleven Utility Scale Solar facilities, and numerous Distributed Solar facilities. Through its relationships with solar equipment providers, NRG can deploy diverse solar technologies in both the utility and distributed generating scale projects that create value for the Company while meeting the clean renewable energy requirements of its customers. In addition, NRG is responding to the growing consumer demand for cleaner transportation solutions by building the first privately funded Electric Vehicle, or EV, charging infrastructure network in select major metropolitan areas.

Sponsor of NRG Yield

The Company’s establishment of, and majority interest in, NRG Yield, Inc. provides it with a more competitive and efficient vehicle to invest in, develop and pursue the acquisition of contracted power infrastructure assets such as conventional and renewable generation assets as well as thermal infrastructure assets. Because the Company believes NRG Yield, Inc. will provide it with a lower cost of capital, NRG believes that it will directly benefit from NRG Yield, Inc.’s growth through its controlling interest in NRG Yield, Inc. and by providing NRG Yield, Inc. a platform of growth through the completion of future sales of assets pursuant to the Right of First Offer Agreement. The proceeds of such sales are expected to provide the Company with capital to expand its Capital Allocation Program. As of December 31, 2013, NRG Yield, Inc.’s stock price had increased 81.9% from its initial public offering price of $22 per share on July 17, 2013.

Reliability of future cash flows and portfolio diversification

NRG has hedged a portion of its coal and nuclear capacity with decreasing hedge levels through 2018. As a result of the GenOn acquisition, the majority of the Company's generation is in markets with forward capacity markets that extend three years into the future. These capacity revenues not only enhance the reliability of future cash flows but are not correlated to natural gas prices. NRG also has cooperative load contract obligations in the South Central region expiring over various dates through 2025, which largely hedge the Company's generation in this region. In addition, as of December 31, 2013, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 61% of its expected coal requirement from 2014 to 2018, excluding inventory. The Company intends to enter into additional hedges when market conditions are favorable. The Company also has the advantage of being able to supply its Retail Business with its own generation, which can reduce the need to sell and buy power from other institutions and intermediaries, resulting in lower transaction costs and credit exposures. This combination of generation and retail allows for a reduction in actual and contingent collateral, through offsetting transactions and by reducing the need to hedge the retail power supply through third parties.

The generation and retail combination also provides stability in cash flows, as changes in commodity prices generally have offsetting impacts between the two businesses. The offsetting nature of generation and retail, in relation to changes in market prices, is an integral part of NRG's goal of providing a reliable source of future cash flow for the Company.

When developing new renewable and conventional power generation facilities, NRG typically secures long-term PPAs, which insulate the Company from commodity market volatility and provide future cash flow stability. These PPAs are typically contracted with high credit quality local utilities and have durations up to 25 years. Such projects include all of the Company's major Utility Scale Solar projects, in operation and under construction, as well as the 720 MW Marsh Landing Generating Station and the 550 MW El Segundo Energy Center.

Commercial Operations Overview

NRG seeks to maximize profitability and manage cash flow volatility through the marketing, trading and sale of energy, capacity and ancillary services into spot, intermediate and long-term markets and through the active management and trading of emissions allowances, fuel supplies and transportation-related services. The Company's principal objectives are the realization of the full market value of its asset base, including the capture of its extrinsic value, the management and mitigation of commodity market risk and the reduction of cash flow volatility over time. NRG enters into power sales and hedging arrangements via a wide range of products and contracts, including PPAs, fuel supply contracts, capacity auctions, natural gas derivative instruments and other financial instruments. In addition, because changes in power prices in the markets where NRG operates are generally correlated to changes in natural gas prices, NRG uses hedging strategies that may include power and natural gas forward sales contracts to manage the commodity price risk primarily associated with the Company's coal and nuclear generation assets. The objective of these hedging strategies is to stabilize the cash flow generated by NRG's portfolio of assets.

Coal and Nuclear Operations

The following table summarizes NRG's U.S. Coal and Nuclear capacity and the corresponding revenues and average natural gas prices and positions resulting from Coal and Nuclear hedge agreements extending beyond December 31, 2013, and through 2018 for the Company's Texas and South Central regions:

Texas and South Central	2014	2015	2016	2017	2018	Annual Average for 2014-2018
	(Dollars in millions unless otherwise stated)					
Net Coal and Nuclear Capacity (MW) [a]	6,865	6,290	6,290	6,290	6,290	6,405
Forecasted Coal and Nuclear Capacity (MW) [b]	5,691	4,951	4,789	4,640	4,501	4,914
Total Coal and Nuclear Sales (MW) [c]	5,354	2,828	1,300	1,080	888	2,290
Percentage Coal and Nuclear Capacity Sold Forward [d]	94 %	57 %	27 %	23 %	20 %	47 %
Total Forward Hedged Revenues [e]	$1,952	$1,083	$531	$461	$411	
Weighted Average Hedged Price ($ per MWh) [e]	$41.62	$43.71	$46.68	$48.60	$52.87	
Average Equivalent Natural Gas Price ($ per MMBtu)	$4.35	$4.53	$5.02	$5.36	$5.97	
Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$16	$124	$190	$196	$198	
Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$(15)	$(110)	$(169)	$(168)	$(170)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$48	$94	$129	$160	$168	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	$(36)	$(73)	$(104)	$(132)	$(135)	

(a) Net Coal and Nuclear capacity represents nominal summer net MW capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units, see Item 2 - Properties for units scheduled to be deactivated.

(b) Forecasted generation dispatch output (MWh) based on forward price curves as of December 31, 2013, which is then divided by number of hours in a given year to arrive at MW capacity. The dispatch takes into account planned and unplanned outage assumptions.

(c) Includes amounts under power sales contracts and natural gas hedges. The forward natural gas quantities are reflected in equivalent MWh based on forward market implied heat rate as of December 31, 2013, and then combined with power sales to arrive at equivalent MWh hedged which is then divided by number of hours in given year to arrive at MW hedged. The Coal and Nuclear Sales include swaps and delta of options sold which is subject to change. For detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements. Includes inter-segment sales from the Company's wholesale power generation business to the Retail Business.

(d) Percentage hedged is based on total Coal and Nuclear sales as described in (c) above divided by the forecasted Coal and Nuclear capacity.

(e) Represents U.S. Coal and Nuclear sales, including energy revenue and demand charges. For purpose of consistency, rail rates for South Central were held constant.

The following table summarizes NRG's U.S. Coal capacity and the corresponding revenues and average natural gas prices and positions resulting from Coal hedge agreements extending beyond December 31, 2013, and through 2018 for the East region:

East	2014	2015	2016	2017	2018	Annual Average for 2014-2018
	(Dollars in millions unless otherwise stated)					
Net Coal Capacity (MW) [(a)]	6,787	6,255	5,433	4,992	4,992	5,692
Forecasted Coal Capacity (MW) [(b)]	3,215	2,276	1,766	1,682	1,718	2,132
Total Coal Sales (MW) [(c)]	2,607	948	482	371	—	881
Percentage Coal Capacity Sold Forward [(d)]	81 %	42 %	27 %	22 %	— %	41 %
Total Forward Hedged Revenues [(e)]	$1,339	$478	$258	$167	$—	
Weighted Average Hedged Price ($ per MWh) [(e)]	$58.65	$57.60	$61.08	$51.21	$—	
Average Equivalent Natural Gas Price ($ per MMBtu)	$5.58	$5.22	$5.36	$4.53	$—	
Gas Price Sensitivity Up $0.50/MMBtu on Coal Units	$97	$112	$94	$101	$117	
Gas Price Sensitivity Down $0.50/MMBtu on Coal Units	$(47)	$(66)	$(56)	$(58)	$(75)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal Units	$84	$122	$96	$99	$102	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal Units	$(40)	$(83)	$(68)	$(67)	$(68)	

(a) Net Coal capacity represents nominal summer net MW capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units, see Item 2 - Properties for units scheduled to be deactivated.

(b) Forecasted generation dispatch output (MWh) based on forward price curves as of December 31, 2013, which is then divided by number of hours in a given year to arrive at MW capacity. The dispatch takes into account planned and unplanned outage assumptions.

(c) Includes amounts under power sales contracts and natural gas hedges. The forward natural gas quantities are reflected in equivalent MWh based on forward market implied heat rate as of December 31, 2013, and then combined with power sales to arrive at equivalent MWh hedged which is then divided by number of hours in given year to arrive at MW hedged. The Coal Sales include swaps and delta of options sold which is subject to change. For detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements. Includes inter-segment sales from the Company's wholesale power generation business to the Retail Business.

(d) Percentage hedged is based on total Coal sales as described in (c) above divided by the forecasted Coal capacity.

(e) Represents U.S. Coal sales, including energy revenue and demand charges, excluding revenues derived from capacity auctions.

Retail Operations

In 2013, the Company's Retail Business sold electricity to residential, commercial and industrial consumers at either fixed, indexed or variable prices. Residential and smaller commercial consumers typically contract for terms ranging from one month to two years while industrial contracts are often between one year and five years in length. In 2013, the Company's Retail Business sold approximately 60 TWhs of electricity. In any given year, the quantity of TWh sold can be affected by weather, economic conditions and competition. The wholesale supply is typically purchased as the load is contracted in order to secure profit margin. The wholesale supply is purchased from a combination of NRG's wholesale portfolio and other third parties, depending on the existing hedge position for the NRG wholesale portfolio at the time. The ability to choose supply from the market or the Company's portfolio allows for an optimal combination to support and stabilize retail margins.

Capacity and Other Contracted Revenue Sources

NRG revenues and cash flows benefit from capacity/demand payments and other contracted revenue sources, originating from market clearing capacity prices, Resource Adequacy contracts, tolling arrangements, PPAs and other long-term contractual arrangements:

- East — The Company's largest sources of capacity revenues are capacity auctions in PJM, ISO-NE, and NYISO. These revenues increased greatly with the addition of the GenOn fleet.
- South Central — NRG earns demand payments from its long-term full-requirements load contracts with ten Louisiana distribution cooperatives. Of the ten contracts, nine expire in 2025 and account for 75% of the cooperative customer contract load, with the remaining contract currently set to expire in 2014. This remaining counterparty, with a 550 MW load service contract, accounting for 25% of the cooperative total, has elected not to extend its contract when it expires in 2014. Demand payments from the current long term contracts are tied to summer peak demand and provide a mechanism for recovering a portion of the costs associated with new or changed environmental laws or regulations. MISO has a Resource Adequacy Construct and an annual auction, known as the Planning Resource Auction, or PRA. In April, MISO will conduct the PRA for Planning Year 2014-2015 that will begin on June 1, 2014. The South Central assets situated in the MISO market may participate in this auction. In certain circumstances, capacity from this region may be sold into the PJM market.
- West — The region's newer generation is contracted under long-term tolling agreements. Certain other sites have short-term tolling agreements or Resource Adequacy contracts.
- Texas — The region's sources of capacity and contracted revenues are through bilateral contracts with load serving entities.
- Other Conventional — Generation output from the Company's share of the Gladstone facility in Australia is sold under long-term contracts, which include capacity payments as well as the reimbursement of certain fixed and variable costs.
- Alternative Energy — Output from solar energy assets is generally sold through long-term PPAs.
- NRG Yield — NRG Yield's share of renewable and conventional energy plants is generally sold through long-term PPAs and tolling agreements. Its share of the GenConn plants in Connecticut also earns fixed payments under long-term financial contracts with a utility counterparty and output from NRG Yield's share of thermal assets is generally sold under long-term contracts or through regulated public utility tariffs. The contracts or tariffs contain capacity or demand elements, mechanisms for fuel recovery and/or the recovery of operating expenses. Two of the PJM generation assets participate in the PJM capacity markets.

Fuel Supply and Transportation

NRG's fuel requirements consist of nuclear fuel and various forms of fossil fuel including coal, natural gas and oil. The prices of fossil fuels are highly volatile. The Company obtains its fossil fuels from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages, transportation availability, delays arising from extreme weather conditions and supplier financial stability issues can and do occur. The preceding factors related to the sources and availability of raw materials are fairly uniform across the Company's business segments and fuel products used.

Coal — The Company believes it is adequately hedged, using forward coal supply agreements for its domestic coal consumption for 2014. NRG actively manages its coal requirements based on forecasted generation, market volatility and its inventory on site. As of December 31, 2013, NRG had purchased forward contracts to provide fuel for approximately 61% of the Company's expected requirements from 2014 through 2018, excluding inventory. NRG purchased approximately 32 million tons of coal in 2013, of which 74% was Powder River Basin coal and lignite, and 26% was Waste and Appalachian coal. For fuel transport, NRG has entered into various rail, barge, truck transportation and rail car lease agreements with varying tenures that provide for substantially all of the Company's transportation requirement of Powder River Basin coal for the next two years and for most of the Company's transportation requirements of Appalachian coal for the next year.

The following table shows the percentage of the Company's coal requirements from 2014 through 2018 that have been purchased forward as of December 31, 2013:

	Percentage of Company's Requirement [(a)(b)]	
2014	97	%
2015	68	%
2016	48	%
2017	47	%
2018	27	%

(a) The hedge percentages reflect the current plan for the Jewett mine, which supplies lignite for NRG's Limestone facility. NRG has the contractual ability to change volumes and may do so in the future.

(b) Does not include coal inventory.

Natural Gas — NRG operates a fleet of mid-merit and peaking natural gas plants across all its U.S. wholesale regions. Fuel needs are managed on a spot basis, especially for peaking assets, as the Company does not believe it is prudent to forward purchase natural gas for units, the dispatch of which is highly unpredictable. The Company contracts for natural gas storage services as well as natural gas transportation services to deliver natural gas when needed.

Nuclear Fuel — STP's owners satisfy their fuel supply requirements by: (i) acquiring uranium concentrates and contracting for conversion of the uranium concentrates into uranium hexafluoride; (ii) contracting for enrichment of uranium hexafluoride; and (iii) contracting for fabrication of nuclear fuel assemblies. Through its proportionate participation in STPNOC, which is the NRC-licensed operator of STP and responsible for all aspects of fuel procurement, NRG is party to a number of long-term forward purchase contracts with many of the world's largest suppliers covering STP's requirements for uranium and conversion services for the next five years, and with substantial portions of STP's requirements procured thereafter. Similarly, NRG is party to long-term contracts to procure STP's requirements for enrichment services and fuel fabrication for the life of the operating license.

Seasonality and Price Volatility

Annual and quarterly operating results of the Company's wholesale power generation segments can be significantly affected by weather and energy commodity price volatility. Significant other events, such as the demand for natural gas, interruptions in fuel supply infrastructure and relative levels of hydroelectric capacity can increase seasonal fuel and power price volatility. NRG derives a majority of its annual revenues in the months of May through October, when demand for electricity is generally at its highest in the Company's core domestic markets. Further, power price volatility is generally higher in the summer months, traditionally NRG's most important season. The Company's second most important season is the winter months of December through March when volatility and price spikes in underlying delivered fuel prices have tended to drive seasonal electricity prices. The preceding factors related to seasonality and price volatility are fairly uniform across the Company's wholesale generation business segments.

The sale of electric power to retail customers is also a seasonal business with the demand for power generally peaking during the summer months. As a result, net working capital requirements for the Company's retail operations generally increase during summer months along with the higher revenues, and then decline during off-peak months. Weather may impact operating results and extreme weather conditions could materially affect results of operations. The rates charged to retail customers may be impacted by fluctuations in total power prices and market dynamics like the price of natural gas, transmission constraints, competitor actions, and changes in market heat rates.

Regional Segment Review

Revenues

The following table contains a summary of NRG's operating revenues by segment for the years ended December 31, 2013, 2012, and 2011, as discussed in Item 15 — Note 18, Segment Reporting, to the Consolidated Financial Statements. Refer to that footnote for additional financial information about NRG's business segments and geographic areas, including a profit measure and total assets. In addition, refer to Item 2 — Properties, for information about facilities in each of NRG's business segments.

	Year Ended December 31, 2013						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[a]	Total Operating Revenues
	(In millions)						
Retail	$—	$—	$6,297	$(5)	$ (51)	$ —	$6,241
Texas	2,190	103	—	(217)	2	28	2,106
East	2,400	1,099	—	(366)	—	76	3,209
South Central	566	245	—	45	19	(1)	874
West	155	314	—	2	—	4	475
Other Conventional Generation	—	5	—	—	—	148	153
Alternative Energy	209	3	—	(1)	—	22	233
NRG Yield	86	91	—	—	(1)	137	313
Corporate and Eliminations [b]	(2,076)	(60)	(5)	(36)	—	(132)	(2,309)
Total	$3,530	$1,800	$6,292	$(578)	$ (31)	$ 282	$11,295

(a) Primarily consists of revenues generated by the Thermal business, operation and maintenance revenues and unrealized trading activities.

(b) Energy revenues include inter-segment sales primarily between Texas and East, and the Retail Business.

	Year Ended December 31, 2012						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[c]	Total Operating Revenues[d]
	(In millions)						
Retail	$—	$—	$5,893	$(5)	$ (116)	$ —	$ 5,772
Texas	2,406	81	—	(441)	—	28	2,074
East	533	314	—	(12)	—	19	854
South Central	527	240	—	30	20	(10)	807
West	121	124	—	10	—	4	259
Other Conventional Generation	39	41	—	—	—	93	173
Alternative Energy	117	—	—	—	—	8	125
NRG Yield	33	—	—	—	(1)	143	175
Corporate and Eliminations [e]	(1,662)	(38)	(5)	(32)	—	(80)	(1,817)
Total	$2,114	$762	$5,888	$(450)	$ (97)	$ 205	$ 8,422

(c) Primarily consists of revenues generated by the Thermal business, operation and maintenance revenues and unrealized trading activities.

(d) Total operating revenues includes GenOn revenues of $73 million for the period from December 15, 2012 to December 31, 2012.

(e) Energy revenues include inter-segment sales primarily between Texas and East, and the Retail Business.

	Year Ended December 31, 2011						
	Energy Revenues	Capacity Revenues	Retail Revenues[f]	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[g]	Total Operating Revenues

(In millions)							
Retail	$—	$—	$ 5,812	$ 8	$ (178)	$ —	$ 5,642
Texas	2,545	28	—	173	—	86	2,832
East	579	291	—	28	—	26	924
South Central	548	243	—	(12)	20	18	817
West	31	118	—	(4)	—	4	149
Other Conventional Generation	58	70	—	—	(1)	58	185
Alternative Energy	18	—	—	—	—	1	19
NRG Yield	25	—	—	—	—	138	163
Corporate and Eliminations[h]	(1,735)	(14)	(5)	132	—	(30)	(1,652)
Total	$ 2,069	$ 736	$ 5,807	$ 325	$ (159)	$ 301	$ 9,079

(f) Retail revenues include Energy Plus revenues of $63 million for the period from October 1, 2011, to December 31, 2011.

(g) Primarily consists of revenues generated by the Thermal business, operation and maintenance revenues and unrealized trading activities.

(h) Energy revenues include inter-segment sales primarily between Texas and East, and the Retail Business.

Operational Statistics

The following are industry statistics for the Company's fossil and nuclear plants, as defined by the NERC and are more fully described below:

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

Net Heat Rate — The net heat rate represents the total amount of fuel in BTU required to generate one net kWh provided.

Net Capacity Factor — The net amount of electricity that a generating unit produces over a period of time divided by the net amount of electricity it could have produced if it had run at full power over that time period. The net amount of electricity produced is the total amount of electricity generated minus the amount of electricity used during generation.

The tables below present these performance metrics for the Company's U.S. power generation portfolio, including leased facilities and those accounted for through equity method investments, for the years ended December 31, 2013, and 2012:

	Year Ended December 31, 2013						
			Fossil and Nuclear Plants				
	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor		Average Net Heat Rate BTU/kWh	Net Capacity Factor	
	(In thousands of MWh)						
Texas	11,286	40,734	84.5	%	10,200	43.5	%
East	20,061	34,211	80.8		10,100	17.6	
South Central	5,313	16,329	79.6		9,300	36.6	
West	6,779	3,528	90.0		11,200	5.3	
Alternative Energy	1,220	2,159					
NRG Yield [(a)]	1,447	1,109					

	Year Ended December 31, 2012						
			Fossil and Nuclear Plants				
	Net Owned Capacity (MW)[(b)]	Net Generation (MWh)[(c)]	Annual Equivalent Availability Factor		Average Net Heat Rate BTU/kWh	Net Capacity Factor	
	(In thousands of MWh)						
Texas	10,880	37,695	83.2	%	10,200	40.7	%
East	21,080	6,469	84.0		11,200	9.8	
South Central	5,315	15,927	80.5		9,400	42.6	
West	7,520	2,146	88.8		12,000	11.9	
Alternative Energy	674	1,367					
NRG Yield [(a)]	351	782					

(a) NRG Yield excludes thermal generation.

(b) Net Capacity Owned includes GenOn assets, which were acquired on December 14, 2012. These include 14,850 MW in East, 1,200 MW in South Central, and 5,390 MW in West.

(c) Net Generation includes GenOn generation for the period from December 15, 2012 through December 31, 2012.

The generation performance by region for the three years ended December 31, 2013, 2012, and 2011, is shown below:

	Net Generation		
	2013	2012 [(a)]	2011
	(In thousands of MWh)		
Texas			
Coal	28,215	24,825	30,256
Gas	4,636	4,709	5,949
Nuclear [(b)]	7,883	8,161	8,960
Total Texas	40,734	37,695	45,165
East			
Coal	25,136	4,514	5,551
Oil	1,073	228	83
Gas	8,002	1,727	1,656
Total East	34,211	6,469	7,290
South Central			
Coal	9,420	8,923	10,865
Gas	6,909	7,004	5,135
Total South Central	16,329	15,927	16,000
West			
Gas	3,528	2,146	1,052
Total West	3,528	2,146	1,052
Alternative Energy			
Solar	1,031	470	—
Wind	1,128	897	838
Total Alternative Energy	2,159	1,367	838
NRG Yield			
Solar	688	270	79
Wind	334	351	345
Gas and Dual-Fuel	87	161	86
Total NRG Yield [(c)]	1,109	782	510

(a) Includes GenOn generation for the period from December 15, 2012 through December 31, 2012.
(b) MWh information reflects the Company's undivided interest in total MWh generated by STP.
(c) Total NRG Yield excludes thermal generation.

Market Framework

Organized Energy Markets in CAISO, ERCOT, ISO-NE, MISO, NYISO and PJM

The majority of NRG's fleet operates in one of the organized energy markets, known as RTOs or ISOs. Each organized market administers day-ahead and real-time centralized bid-based energy and ancillary services markets pursuant to tariffs approved by the FERC, or in the case of ERCOT, market rules approved by the PUCT. These tariffs and rules dictate how the energy markets operate, how market participants make bilateral sales with one another, and how entities with market-based rates are compensated. Established prices reflect the value of energy at the specific location and time it is delivered, which is known as the Locational Marginal Price or LMP. Each market is subject to market mitigation measures designed to limit the exercise of locational market power. These market structures facilitate NRG's sale of power and capacity products at market-based rates.

Other than ERCOT, each of the ISOs also operates a capacity or resource adequacy market that provides an opportunity for generating and demand response resources to earn revenues to offset their fixed costs that are not recovered in the energy and ancillary services markets. The ISOs are also responsible for transmission planning and operations.

Texas

NRG's Texas wholesale power generation business is in the physical control area of the ERCOT market. The ERCOT market is one of the nation's largest and historically fastest growing power markets. For 2013, hourly demand ranged from a low of approximately 23,400 MW to a high of approximately 67,200 MW. The all-time peak demand in ERCOT remains 68,305 MW, set on August 3, 2011 during the hottest summer on record. The ERCOT region contains installed generation capacity of approximately 89,200 MW (approximately 23,300 MW from coal, lignite and nuclear plants, 48,600 MW from gas, and 17,300 MW from wind, hydro, solar, biomass and behind-the-meter generation). The ERCOT market has limited interconnections to other markets in the United States. In addition, NRG's Retail Business activities in Texas are subject to standards and regulations adopted by the PUCT and ERCOT, including the requirement for retailers to be certified by the PUCT in order to contract with end-users to sell electricity. In Texas, a majority of the load is in the ERCOT market and is served by competitive retail suppliers. Certain areas of the state are served by municipal utilities and electric cooperatives.

Regulators, legislators, and stakeholders in ERCOT have been conducting a lengthy debate on how to address projected shortfalls in planning reserve margins that may occur in 2015 and beyond. A number of market rule changes have been implemented to provide pricing more reflective of higher energy value when operating reserves are scarce or constrained. The primary stated goal of these market rule changes is to improve forward market pricing signals and provide incentives for resource investment. Among the changes already implemented are: energy offer floors for certain ancillary service deployments, an increase to the system-wide energy and ancillary service offer caps (currently at $5,000 per MWh but increasing to $7,000 in June 2014 and to $9,000 in June 2015), an increase to the annual peaker net margin threshold to $262,500 from $175,000, an increase to the low system-wide energy offer cap to $2,000 (up from $500), and higher energy pricing for ISO unit commitments for capacity.

On or about June 1, 2014, ERCOT will implement an operating reserve demand curve, or ORDC, which is being designed to provide additional administrative pricing adjustments during operational shortages, and ERCOT is working on other proposals to address price dampening from minimum energy from online resources, and emergency supply procurement in a manner that does not suppress competitive pricing. Longer term proposals are also under high level review, including a potential forward capacity market model related to supporting reserve requirements.

East

NRG's generation assets located in the East region of the United States are within the control areas of the NYISO, ISO-NE, and PJM. Each of the market regions in the East region provides for robust competition in the day-ahead and real-time energy and ancillary services markets. Additionally, each allows capacity resources to compete for fixed cost recovery in a capacity auction.

The East region achieves a significant portion of its revenues from capacity markets in ISO-NE, NYISO and PJM. PJM and ISO-NE employ a three-year forward capacity auction construct, while NYISO employs a month-ahead capacity auction construct. Capacity market prices are sensitive to design parameters, as well as additions of new capacity.

NRG's Retail Business is active in a number of areas in the East region that have introduced retail competition, which allows NRG to competitively provide retail power, natural gas and other value-enhancing services to end use customers. Each retail choice state establishes its own retail competition laws and regulations, and the specific operational, licensing, and compliance requirements vary on a state-by-state basis. The Company's Retail Business holds licenses in many of the states that allow for retail choice in C&I and/or Mass markets. In the East markets, incumbent utilities currently provide default service and as a result typically serve a majority of residential customers. Primary factors in the success of retail competition include how the state provides and prices default service. However, as customers become more informed about the many benefits of retail choice and states continue to implement retail policies to further improve market dynamics, retail choice is expected to grow. The Retail Business continues to expand in the competitive choice states and offers a range of value propositions to consumers to meet individual and business preferences.

The East Region also includes the Osceola plant that is outside the organized eastern markets. It is located in FRCC and is currently under a tolling arrangement that expires in 2014.

South Central

On December 19, 2013, Entergy joined MISO and, as a result, the generation assets located in NRG's South Central region which operated primarily in the SERC-Entergy region, now are within the MISO control area. NRG's South Central assets compete in the MISO day-ahead and real-time energy and ancillary services markets. Additionally, MISO employs a one-year forward capacity auction construct, in which capacity resources can compete for fixed cost recovery in the capacity auction. NRG continues to provide full requirement services to load-serving entities, including cooperatives and municipalities.

West

The Company operates a fleet of natural gas fired facilities located entirely within the CAISO footprint. The CAISO operates day-ahead and real-time locational markets for energy and ancillary services, while managing congestion primarily through nodal prices. The CAISO system facilitates NRG's sale of power and capacity products at market-based rates, or bilaterally pursuant to tolling arrangements with California's load serving entities, or LSEs. The CPUC also determines specific capacity requirements for specified local areas utilizing inputs from the CAISO. Both CAISO and CPUC rules require LSEs to contract with sufficient generation resources in order to maintain minimum levels of generation within defined local delivery areas. Additionally, the CAISO has independent authority to contract with needed resources under certain circumstances.

The increase in renewable resources in California is expected to drive a growing need for generation resources with increased operating flexibility, in addition to the established need for dispatchable generation within transmission-constrained areas of the transmission system, such as the San Diego, Greater San Francisco Bay Area, Big Creek/Ventura, and Los Angeles local reliability areas in which the Company currently operates natural gas-fired generation. The projected retirement of older flexible gas-fired coastal generating units that utilize once-through cooling is also a significant driver of long-term prices in California. Implementing market mechanisms to procure the needed flexibility, and allocating the costs associated with this flexibility, are key CAISO initiatives. The Company's Marsh Landing and El Segundo Energy Center projects, which both reached commercial operation in 2013 and are the subject of long-term tolling agreements, are examples of the type of flexible natural gas-fired generation resources that the CAISO has identified as necessary to maintain system reliability. The Company is also pursuing repowering projects at several of its Southern California sites to help meet local generation needs already established by, as well as additional needs currently under consideration by, the CPUC. Specifically, through a subsidiary, the Company has executed an agreement with the City of Carlsbad dated January 14, 2014, that secures the support of the City of Carlsbad for a license amendment for the Carlsbad Energy Center. Another Company subsidiary has filed a petition to amend the license for the El Segundo Energy Center to add additional new generating units at that site, completing its modernization. Longer term, NRG's California portfolio's locational advantage may be impacted by new transmission, which may affect load pocket procurement requirements, and by the state's goal for additional distributed generation, which may also be located within these constrained local areas.

Solar

The Company also operates a fast-growing fleet of Utility Scale Solar and Distributed Solar generating assets within the CAISO system, as well as within balancing authorities in Arizona and New Mexico. Each of these states has implemented their own renewable portfolio standard requiring LSEs to provide a given percentage of their production from renewable resources, such as 33% of generation by 2020 in California. As a result, a number of LSEs have entered into long-term PPAs with the Company's Utility Scale Solar generating facilities. The Company currently has PPAs for over 1,100 MW of solar generation assets, over 750 MWs of which are located in California. In California and Arizona, investor-owned utilities are nearing their procurement requirement, resulting in a trend towards smaller sized Utility Scale projects and a shift of contracting to municipalities and other public power entities. Distributed Solar opportunities remain strong as declining project costs allow pricing, without subsidies, to continue to approach parity with utility rates. As success in the Distributed Solar segment of the market builds, the states' public utility commissions are expected to reevaluate policies created to encourage the growth of this market segment, including the role of net energy metering (in California) and tariff subsidies (as evidenced by the end of commercial and industrial customer incentives in Arizona).

New and On-going Company Initiatives and Development Projects

Proposed EME Acquisition

On October 18, 2013, the Company entered into an agreement to acquire substantially all of the assets of Edison Mission Energy, or EME. EME, through its subsidiaries and affiliates, owns, operates, and leases a portfolio of 8,000 MW consisting of wind energy facilities and coal- and gas-fired generating facilities. On December 17, 2012, EME and certain of its direct and indirect subsidiaries filed voluntary petitions for relief under chapter 11 of title 11 of the United States Code, or the Bankruptcy Code. EME was deconsolidated from its parent company, Edison International, for financial statement purposes but not for tax purposes on December 17, 2012. On May 2, 2013, certain other subsidiaries of EME filed voluntary petitions for relief under the Bankruptcy Code.

The Company will pay an aggregate purchase price of $2.6 billion (subject to adjustment), which will consist of 12,671,977 shares of NRG common stock (valued at $350 million based upon the volume-weighted average trading price over the 20 trading days prior to October 18, 2013) with the balance to be paid in cash. The Company expects to fund the cash portion of the purchase price using a combination of cash on hand, including acquired cash on hand of $1.1 billion, and approximately $700 million of the proceeds received from the issuance of the 2022 Senior Notes, as discussed in Item 15 — Note 12, Debt and Capital Leases. The Company also expects to assume debt related to acquired project assets of approximately $1.5 billion, which will be non-recourse to NRG.

In connection with the transaction, NRG has agreed to certain conditions with the parties to the Powerton and Joliet, or POJO, sale-leaseback transaction subject to which an NRG subsidiary will assume the POJO leveraged leases and NRG will guarantee the remaining payments under each lease. In connection with this agreement, NRG has committed to fund up to $350 million in capital expenditures for plant modifications at Powerton and Joliet to install controls to comply with MATS.

The acquisition is subject to customary conditions, including approval of the U.S. Bankruptcy Court for the Northern District of Illinois and required regulatory approvals, and is expected to close by the end of the first quarter of 2014. There are no assurances that the conditions to the acquisition of EME will be satisfied, that EME will not enter into an alternative transaction, or that the acquisition of EME will be consummated on the terms agreed to, if at all.

Public Offering of NRG Yield, Inc.

The Company created NRG Yield, Inc. to enhance value for its stockholders by seeking to gain access to an alternative investor base with a more competitive source of equity capital that would accelerate NRG Yield, Inc.'s long-term growth and acquisition strategy and optimize the NRG Yield, Inc. capital structure. In addition, the creation of NRG Yield, Inc. highlights the value inherent in NRG's contracted conventional and renewable generation and thermal infrastructure assets by separating them from other NRG non-contracted assets. Because the Company believes NRG Yield, Inc. will provide it with a lower cost of capital, NRG believes that it will directly benefit from NRG Yield, Inc.’s growth through its controlling interest in NRG Yield, Inc. and by providing NRG Yield, Inc. a platform of growth through the completion of future sales of assets. NRG Yield, Inc. completed its initial public offering in July 2013, as described in Item 15 — Note 1, Basis of Presentation, and received net proceeds after underwriting discounts of $468 million, of which $395 million was utilized to acquire the contracted assets from NRG and $73 million was retained for NRG Yield, Inc.'s general corporate purposes.

NRG has given NRG Yield, Inc. the right of first offer for certain of its assets if it should seek to sell the assets. These assets include the following: El Segundo Energy Center, High Desert, Kansas South, NRG's interest in Agua Caliente (51%), a portion of NRG's interest in Ivanpah (49.95%) and NRG's remaining interest in CVSR.

Certain of the contracted assets acquired by NRG Yield, Inc. in July 2013 were in development in 2013 and are further described below, including Alpine, Borrego and CVSR. On December 31, 2013, a subsidiary of NRG Yield, Inc. acquired a 100% interest in Energy Systems Company, or Energy Systems. Energy Systems is an operator of steam and chilled thermal facilities that provides heating and cooling services to nonresidential customers in Omaha, Nebraska.

Renewable Development and Acquisitions

As part of its core strategy, NRG intends to continue to own, operate and invest in the development and acquisition of renewable energy projects. NRG's renewable strategy is intended to capitalize on scale and first mover advantage in a high growth segment of the energy sector and the Company's existing wholesale and retail businesses in states with policies and market opportunities conducive to the development of a growing utility scale and distributed solar business. In particular, as the installed cost of new renewable resources continues to decline, the Company intends to target opportunities in markets where alternative energy solutions have, or are becoming, increasingly price competitive to system power and the electricity distribution systems have become increasingly susceptible to service disruption as a result of, among other factors, extreme weather. This section briefly describes the Company's most notable current activities in renewable development.

Solar

NRG has acquired and is developing a number of solar projects utilizing photovoltaic, or PV, as well as solar thermal technologies. As of December 31, 2013, NRG had 1,186 MW of capacity at its commercially operating solar facilities, which includes the assets in service at Ivanpah, Agua Caliente, CVSR, Alpine, Borrego, High Desert, Kansas South, Distributed Solar, among others. The following table is a brief summary of the Company's major Utility Scale Solar projects, as of December 31, 2013, that are or were under construction during the fourth quarter.

NRG Owned Projects	Location	PPA	MW (a)	COD or Expected COD	Status
Guam	Guam, U.S. territory	25 year	26	2014	Under Construction
Ivanpah (b)	Ivanpah, CA	20 - 25 year	378	2013	In-Service
CVSR (c)	San Luis Obispo, CA	25 year	250	2012 - 2013	In-Service

(a) Represents total project size.

(b) NRG owns a 50.1% stake in the Ivanpah solar project.

(c) NRG owns a 51.05% stake of CVSR and owns a 65.5% stake of NRG Yield Inc.'s 48.95% stake of CVSR, for a total 83% stake in the 250 MW CVSR project, of which NRG consolidates its interest.

Below is a summary of recent developments related to solar projects:

Ivanpah — Ivanpah achieved operations as of December 31, 2013. Power generated from Ivanpah is being sold to Southern California Edison and PG&E under multiple 20 to 25 year PPAs.

Agua Caliente — On January 18, 2012, the Company completed the sale of a 49% interest in NRG Solar AC Holdings LLC, the indirect owner of Agua Caliente, to MidAmerican Energy Holdings Company. Operations commenced in phases through the third quarter of 2013, with 253 MW having achieved commercial operations from January through December of 2012. Full commercial operations of the entire 290 MW project was achieved as of September 30, 2013. Power generated from Agua Caliente is being sold to PG&E under a 25 year PPA.

CVSR — Operations commenced on the first 22 MW phase in September 2012 and 105 MWs for phases 2 and 4 in December 2012. For the completion of the final phase, 21 MWs commenced operation in the third quarter of 2013 and 102 MWs commenced operation in October 2013. Power generated from CVSR is sold to PG&E under 25 year PPAs.

High Desert — In the first quarter of 2013, the Company, through its wholly-owned subsidiary, NRG Solar PV LLC, acquired High Desert, a 20 MW utility-scale photovoltaic solar facility located in Lancaster, California. The project was financed with $24 million in equity and $82 million of nonrecourse project level debt as discussed in Note 12, Debt and Capital Leases. The solar facility provides electricity to Southern California Edison under a 20-year PPA.

Kansas South — In the second quarter of 2013, the Company, through its wholly-owned subsidiary, NRG Solar PV LLC, acquired Kansas South, a 20 MW utility-scale photovoltaic solar facility located in Kings County, California. The project was financed with $21 million in equity and $59 million of nonrecourse project level debt as discussed in Note 12, Debt and Capital Leases. The solar facility provides electricity to PG&E under a 20-year PPA.

Guam Solar Project — In 2013, the Company, through its wholly-owned subsidiary, NRG Solar Guam LLC, acquired a 26 MW solar project in the development phase on the island of Guam, a U.S. territory. NRG, through its subsidiaries, will construct, own and operate the solar project which will sell all of its power output to the Guam Power Authority under a 25-year PPA. Construction commenced in the fourth quarter of 2013 and the project is expected to attain full commercial operation by the fourth quarter of 2014. The project will be financed with nonrecourse project level debt as discussed in Note 12, Debt and Capital Leases.

Distributed Solar — Approximately 53 MWs of distributed solar projects are in operation or construction at five National Football League venues as well as other commercial or institutional sites. A critical initiative of the Company's Distributed Solar growth effort aims to establish alliances with large customers seeking renewable energy at multiple locations. This effort resulted in the May 2013 announcement of a global alliance with Starwood Hotels & Resorts Worldwide and the July 2013 announcement of a planned installation at one of the largest contiguous rooftop solar photovoltaic arrays in the world at the Mandalay Bay Resort Convention Center in Las Vegas. All of the Company's Distributed Solar projects in operation or under construction are supported by long-term PPAs.

Conventional Power Development

Operational Improvement Activities

NRG has announced its intention to continue operations at the Avon Lake and New Castle facilities, which are currently in operation and had been scheduled for deactivation in April 2015. NRG intends to add natural gas capabilities at these facilities, which is expected to be completed by the summer of 2016. The Company also expects to add natural gas capabilities at the Big Cajun II facility by spring of 2015.

In December 2013, the New York Governor announced a deal under which the Company and National Grid will negotiate a contract to add gas to the Dunkirk facility to enable Units 2, 3 and 4 to operate on natural gas. Unit 1 will remain mothballed. The Company and National Grid agreed to the material terms of a ten-year contract, and those terms were filed with the NYPSC on February 13. The agreement will commence when the three Dunkirk Units are capable of operating on natural gas, expected in the fall of 2015.

Projects Under Construction

The Company's ESEC completed construction at its El Segundo Power Generating Station, a 550 MW fast start, gas turbine combined cycle generating facility in El Segundo, California. The facility was constructed pursuant to a 10 year, 550 MW PPA with Southern California Edison. The first and second units reached commercial operation on June 28 and July 10, 2013, respectively.

The Company completed construction of the Marsh Landing project, a 720 MW natural gas-fired peaking facility adjacent to the Company's Contra Costa generating facility near Antioch, California, in 2013. The output of the facility is contracted to PG&E pursuant to a 10 year PPA. The project achieved commercial operations on May 1, 2013. In July 2013, NRG transferred ownership of the Marsh Landing project to NRG Yield LLC.

Gregory Acquisition

On August 7, 2013, NRG Texas Gregory LLC, a wholly-owned subsidiary of NRG, acquired the Gregory cogeneration plant in Corpus Christi, Texas from a consortium of affiliates of Atlantic Power Corporation, John Hancock Life Insurance Company (U.S.A.), and Rockland Capital, LLC. NRG paid approximately $245 million, net of $32 million cash acquired, for the plant, which has generation capacity of 388 MW and steam capacity of 160 MWt. The Gregory cogeneration plant provides steam, processed water and a small percentage of its electrical generation to the Corpus Christi Sherwin Alumina plant. The majority of the plant's generation is available for sale in the ERCOT market.

W.A. Parish Peaking Unit and Commercial Scale Carbon Capture and Sequestration with Enhanced Oil Recovery

The 75 MW peaking unit at W.A. Parish achieved commercial operations on June 26, 2013. The unit is expected to be retrofitted for use as a cogeneration facility to provide steam and power to operate the CCS-EOR, which is being partially funded by a grant from the U.S. DOE.

Construction of the CCS-EOR is intended to allow NRG, through its wholly owned subsidiary Petra Nova LLC, to utilize the captured CO_2 in enhanced oil recovery operations in oil fields on the Texas Gulf Coast. On May 23, 2013, the U.S. DOE published the Record of Decision in the Federal Register, announcing its decision to provide cost-shared funding for the project in the amount of $167 million, $7 million of which has already been received by

NRG as of December 31, 2013. Construction of the CCS-EOR is subject to receipt of appropriate financing and negotiation of material contracts.

Retail Growth Initiatives

NRG's Retail Business continues to develop innovative products and services that help change the way consumers and businesses think about and use energy. In the Texas residential segments, the Company continued to expand its solar offering. In addition to introducing the first 100% solar product in Texas that also helps fund the development of new solar in the state, solar lease offers were introduced to customers. NRG has also expanded its home energy services to include home energy reviews and peer comparison, personal recommendations and a state-of-the-art mobile experience that gives customers insights to make energy choices that fit their personal preferences. New sales partnerships have also been created with plans to offer a variety of products and services to customers shopping at national retail stores consistent with the strategy to meet customers where they are with products and services that power their homes and their lives. In the Texas business segment, the Company continued offering energy solutions including the weekly summary email, usage alerts, Nest Thermostat, Entouch Controls, and Smart Outlets, giving customers insights, choices and convenient ways to manage energy use.

In the Northeast, NRG has expanded its offerings for businesses and households. In the business segment, in 2013, NRG completed the acquisition of and continued integrating Energy Curtailment Specialists, or ECS. This is a critical portion of the Company's strategy of engaging differently with business customers. The Company's ECS acquisition allows NRG to offer demand response to current commodity customers. In addition, NRG is seeking to deepen its overall relationship by selling energy efficiency and energy supply consulting services to a range of business customers. In the residential segment, customer count growth was primarily achieved by focusing on the Green Mountain Energy and NRG Residential Solutions brands. Green Mountain’s growth was enabled by the sales force penetration in the new distribution utility service territories we entered earlier during 2013. The Company's launch of the NRG Residential Solutions brand now provides NRG access into 22 utility territories in 10 states and Washington, DC and the Company's brand is gaining awareness in its key markets. Through NRG Residential Solutions NRG launched a unique bundled offer providing fixed price electricity with a residential rooftop solar panel offer for households that are interested in distributed generation and price control. Finally, to support sales for all retail brands in the Northeast, the Company continues to expand its retail storefront sales partnerships to find new locations to engage consumers.

Electric Vehicle Infrastructure Development

NRG, through its subsidiary NRG eVgo, continues to build out and operate EV ecosystems in the San Francisco Bay Area, Los Angeles, San Diego, Washington, DC/Baltimore, Houston and the Dallas/Fort Worth Metroplex. NRG eVgo is the first company to equip major markets with privately funded infrastructure needed for successful EV adoption and integration. As of December 31, 2013, NRG eVgo had 57 public fast charging Freedom Station sites operational in its metro areas. NRG eVgo has an additional 33 sites in its metro areas under construction or in permitting. NRG eVgo offers consumers a subscription-based plan that provides for all charging requirements for EVs at a competitive monthly fee. NRG eVgo achieved billable network status in Texas in 2012, and is on track to achieve billable network status in San Francisco, San Diego, and Washington by the first quarter of 2014 and in Los Angeles by the second quarter of 2014.

NRG eVgo has an agreement with the California Public Utilities Commission to build at least 200 public fast charging Freedom Station sites and wiring and associated work to prepare 10,000 commercial and multi-family parking spaces for electric vehicle charging in California by the end of 2016. The agreement is part of a legal settlement, as discussed in detail in Item 15 — Note 22, Commitments and Contingencies, to the Consolidated Financial Statements, and was approved by the FERC on November 2, 2012.

Regulatory Matters

As operators of power plants and participants in wholesale and retail energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include the U.S. Commodity Futures Trading Commission, FERC, NRC, and the PUCT, as well as other public utility commissions in certain states where NRG's generating, thermal, or distributed generation assets are located. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO and RTO markets in which it participates. Likewise, certain NRG entities participating in the retail markets are subject to rules and regulations established by the states in which NRG entities are licensed to sell at retail. NRG must also comply with the mandatory reliability requirements imposed by the North American Electric Reliability Corporation and the regional reliability entities in the regions where the Company operates.

NRG's operations within the ERCOT footprint are not subject to rate regulation by FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. These operations are subject to regulation by the PUCT, as well as to regulation by the NRC with respect to the Company's ownership interest in STP.

Federal Regulation

CFTC

The CFTC has regulatory authority over the trading of physical commodities, futures and other derivatives under the Commodity Exchange Act, or CEA. The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, increased the CFTC's regulatory authority on matters related to futures and over-the-counter derivatives trading, including, but not limited to: trading practices, trade clearance, transaction reporting and record keeping, position limits, and market participant capital and margin requirements. The Company has reached the conclusion that it is neither a swap dealer nor a major swap participant and has taken and will continue to take measures to otherwise comply with the Dodd-Frank Act.

The Company expects that, in 2014 and thereafter, the CFTC will further clarify the scope of the Dodd-Frank Act and publish additional rules concerning position limits, margin requirements and other issues that will affect the Company's futures and over-the-counter derivatives trading. Because there are many details that remain to be addressed through CFTC rulemaking proceedings, at this time NRG cannot fully measure the impact of the Dodd-Frank Act on the Company, its operations or collateral requirements.

FERC

FERC regulates, among other things, the transmission and the wholesale sale by public utilities of electricity in interstate commerce under the authority of the FPA. Under existing regulations, FERC determines whether an entity owning a generation facility is an EWG as defined in the PUHCA of 2005. FERC also determines whether a generation facility meets the ownership and technical criteria of a QF under PURPA. The transmission of electric energy occurring wholly within ERCOT is not subject to the FERC's rate jurisdiction under Sections 203 or 205 of the FPA. Each of NRG's non-ERCOT U.S. generating facilities either qualifies as a QF, or the subsidiary owning the facility qualifies as an EWG.

Public utilities are required to obtain FERC's acceptance, pursuant to Section 205 of the FPA, of their rate schedules for the wholesale sale of electricity. All of NRG's non-QF generating and power marketing entities located outside of ERCOT make sales of electricity pursuant to market-based rates, as opposed to traditional cost-of-service regulated rates.

State Regulation

In Texas, NRG's operations within the ERCOT footprint are not subject to rate regulation by the FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. These operations are subject to regulation by the PUCT, as well as to regulation by the NRC with respect to the Company's ownership interest in STP.

In New York, the Company's generation subsidiaries are electric corporations subject to "lightened" regulation by the NYSPSC. As such, the NYSPSC exercises its jurisdictional authority over certain non-rate aspects of the facilities, including safety, retirements, and the issuance of debt secured by recourse to the Company's generation assets located in New York. The Company currently has blanket authorization from the NYSPSC for the issuance of $15 billion of debt. Additionally, the NYSPSC has provided GenOn Bowline with a separate debt authorization of $1.488 billion.

In California, the Company's generation subsidiaries are subject to regulation by the CPUC with regard to certain non-rate aspects of the facilities, including health and safety, outage reporting and other aspects of the facilities' operations.

Nuclear Operations

NRG South Texas LP is a 44% owner of a joint undivided interest in STP, the other owners of STP being the City of Austin, Texas (16%) and the City Public Service Board of San Antonio (40%). STP Nuclear Operating Company, or STPNOC, was founded by the then-owners in 1973 to operate the plant and it is the operator licensee and holder of the Facility Operating Licenses NPF-76 and NPF-80. STPNOC is a nonstock, nonprofit, nonmember corporation. Each owner of STP appoints a board member (and the three directors then choose a fourth director who also serves as the chief executive officer of STPNOC). A participation agreement establishes an owners committee with voting interests consistent with ownership interests.

As a holder of an ownership interest in STP, NRG South Texas LP is an NRC licensee and is subject to NRC regulation. The NRC license gives the Company the right to only possess an interest in STP but not to operate it. As a possession-only licensee, i.e., non-operating co-owner, the NRC's regulation of NRG South Texas LP is primarily focused on the Company's ability to meet its financial and decommissioning funding assurance obligations. In connection with the NRC license, the Company and its subsidiaries have a support agreement to provide up to $120 million to support operations at STP.

Decommissioning Trusts — Upon expiration of the operating licenses for the two generating units at STP, currently scheduled for 2027 and 2028, the co-owners of STP are required under federal law to decontaminate and decommission the STP facility. Under NRC regulations, a power reactor licensee generally must pre-fund the full amount of its estimated NRC decommissioning obligations unless it is a rate-regulated utility, or a state or municipal entity that sets its own rates, or has the benefit of a state-mandated non-bypassable charge available to periodically fund the decommissioning trust such that the trust, plus allowable earnings, will equal the estimated decommissioning obligations by the time the decommissioning is expected to begin.

NRG South Texas LP, through its 44% ownership interest, is the beneficiary of decommissioning trusts that have been established to provide funding for decontamination and decommissioning of STP. CenterPoint Energy Houston Electric, LLC, or CenterPoint, and American Electric Power, or AEP, collect, through rates or other authorized charges to their electric utility customers, amounts designated for funding NRG South Texas LP's portion of the decommissioning of the facility. NRG South Texas LP filed a decommissioning cost rate case with the PUCT in 2013 based upon a third party cost study and assuming a twenty year license extension, which resulted in a decrease in the rate of collections. The PUCT approved the rate changes. See also Item 15 — Note 6, Nuclear Decommissioning Trust Fund, to the Consolidated Financial Statements for additional discussion.

In the event that the funds from the trusts are ultimately determined to be inadequate to decommission the STP facilities, the original owners of the Company's STP interests, CenterPoint and AEP, each will be required to collect, through their PUCT-authorized non-bypassable rates or other charges to customers, additional amounts required to fund NRG South Texas LP's obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, those excesses will be refunded to the respective rate payers of CenterPoint or AEP, or their successors.

Nuclear Regulatory Commission Task Force Report — On July 12, 2011, the NRC Near-Term Task Force, or the Task Force, issued its report, which reviewed nuclear processes and regulations in light of the accident at the Fukushima Daiichi Nuclear Power Station in Japan. The Task Force concluded that U.S. nuclear plants are operating safely and did not identify changes to the existing nuclear licensing process nor recommend fundamental changes to spent nuclear fuel storage. The Task Force report made recommendations in three key areas: the NRC's regulatory framework, specific plant design requirements, and emergency preparedness and actions. STPNOC expects the report to be the first step in a longer-term review that the NRC will conduct, along with seeking broad stakeholder input. STPNOC continues to apply lessons learned and work with regulators and industry organizations on appropriate assessments and actions.

In March 2012, the NRC ordered each licensee to conduct a review of seismic and flooding risks (beyond the design license basis), along with an evaluation of emergency preparedness, and an evaluation of the adequacy of spent fuel pool integrity. STPNOC completed these evaluations for STP and is participating in an industry-wide effort to establish remote and reliable storage facilities to house and maintain the necessary equipment to sustain safe operation in the event of long-term absence of existing electric grid infrastructure and on-site generating equipment.

Upon review of industry-wide data, the NRC compared the seismic and flooding analyses against lessons learned at the two new construction sites in the United States and required all stations to re-perform the work, using more conservative assumptions. These subsequent reviews did not reveal additional flooding vulnerabilities at STP as reported to the NRC on March 11, 2013. The seismic re-analysis of Unit 1 has been completed satisfactorily and reported to the NRC on April 25, 2013; Unit 2 re-analysis will not be completed until February 2014 since inaccessible areas could only be examined during a refueling shutdown, recently completed in December 2013. Due to the recent analysis conducted in pursuit of a new construction/operating license for Units 3 and 4, significant issues in this regard are not anticipated.

Hardened instrumentation of spent fuel pool instrumentation, improved emergency communications and increased responsive staffing, and the establishment of two FLEX (Flexible Emergency Response Equipment) sites serving the entire industry are on track to meet the NRC's timetable for completion in 2016. With respect to STP, the estimated cost for the currently identified required tasks is projected to be less than $50 million, allocated among the three owners. Until further action is taken by the NRC (including issuance of actions required in response to Tier 2 and 3 recommendations), the Company cannot positively predict the impact of the recommendation in the Task Force report and could be required to make additional investments at STP Units 1 and 2.

Regional Regulatory Developments

NRG is affected by rule/tariff changes that occur in the ISO regions. For further discussion on regulatory developments see Item 15 — Note 23, Regulatory Matters, to the Consolidated Financial Statements.

East Region

PJM

Maryland Environmental Regulations — MDE has announced that it intends to promulgate more stringent regulations regarding NO_x emissions, which could negatively affect some of the Company's coal units in Maryland. Accordingly, on November 29, 2013, NRG submitted a notice of deactivation to retire Chalk Point Units 1 and 2, and Dickerson Units 1, 2, and 3 on May 31, 2017. The deactivation is based on draft environmental regulations that, if adopted, could require uneconomic capital investment and render the units uneconomic to operate going forward.

Import Limits — On November 29, 2013, PJM filed at FERC to add a limit on the amount of capacity from external resources that PJM can reliably import into the PJM Region. If approved by FERC, the capacity import limit may decrease the amount of capacity imports allowed into PJM, as compared to recent auctions. On January 28, 2014, FERC issued a deficiency notice to PJM. On February 20, 2014, PJM filed its response to the deficiency letter, and the matter is still pending at FERC. The outcome of this proceeding could have a material impact on future PJM capacity prices.

Limited Demand Response Caps & Demand Response Operability Filings — On January 30, 2014, FERC approved a PJM proposal to place a ceiling, or hard cap, on the amount of limited and extended summer demand response resources that can clear the auction. The intent of these changes is to drive price separation between the Annual, Extended Summer, and Limited demand response products in PJM and to ensure that the annual product receives the highest payment from the market. The Company supported the filing at FERC and the matter is still pending rehearing. The eventual outcome of this proceeding could have a material impact on future PJM capacity prices.

Additionally, on December 24, 2013, PJM filed at FERC to implement changes governing demand response resources' participation in the PJM capacity market in an attempt to enhance the operational flexibility of demand response resources during the operating day. The host of changes proposed by PJM included proposals to require most demand response resources to respond in 30 minutes and reduce the minimum call time from two hours to one hour. Approval of these changes would likely limit the amount of demand response resources eligible to participate in the PJM capacity market. The Company filed a limited protest that, among other things, sought clarification on the exemptions offered to the 30 minute notification time and challenging the exemption offered to behind the meter generation. The matter is pending at FERC and the outcome of this proceeding could have a material impact on future PJM capacity prices.

MOPR Litigation — On April 12, 2011, FERC issued an order addressing a complaint filed by PJM Power Providers Group seeking to require PJM to address the potential adverse impacts of out-of-market generation on the PJM Reliability Pricing Model capacity market, as well as PJM's subsequent submission seeking revisions to the capacity market design, in particular the MOPR. In its order, FERC generally strengthened the MOPR and the protections against market price distortion from out-of-market generation. On February 18, 2014, the Third Circuit Court of Appeals affirmed FERC's order.

MOPR Revisions — On December 7, 2012, PJM filed comprehensive revisions to its MOPR rules at FERC. On May 2, 2013, FERC accepted PJM's proposal in part, and rejected it in part. Among other things, FERC approved the portions of the PJM proposal that exempt many new entrants from MOPR rules, including projects proposed by merchant generators, public power entities and certain self-supply entities. This exemption is subject to certain conditions designed to limit the financial incentive of such entities to suppress market prices. However, FERC rejected PJM's proposal to eliminate the unit specific review process, and instead directed PJM to continue allowing units to demonstrate their actual costs and revenues, and bid into the auction at that price. On June 3, 2013, the Company filed a request for rehearing of the FERC order and subsequently protested the manner in which PJM proposed to implement the FERC order. These challenges are both pending.

New Jersey and Maryland's Generator Contracting Programs — In 2011, the New Jersey Board of Public Utilities, or NJBPU, awarded three Standard Offer Capacity Agreements, or SOCAs as part of New Jersey's Long-Term Capacity Agreement Pilot Program. The stated goal of the program was to encourage the construction of new generation capacity in New Jersey. One of the SOCAs was awarded to a Company affiliate, which has since been terminated. In late 2011, the MD PSC awarded a similar contract to another generation developer.

The constitutionality of the SOCAs awarded by the NJBPU to the Company and other entities were challenged in the U.S. District Court for the District of New Jersey. On October 11, 2013, the federal district court held that the SOCAs violated the Supremacy Clause of the U.S. Constitution because they intruded on the authority Congress had granted to FERC under the FPA to set wholesale energy prices, which authority FERC had expressed through the PJM capacity auction. Additionally, the Court found that the SOCA poses an obstacle to FERC's implementation of the PJM capacity auction. Based on these findings, the federal district found the SOCAs to be null and void.

In a similar challenge lodged in the U.S. District Court for the District of Maryland against the Maryland contract, the Maryland federal district court ruled on September 30, 2013 that the Maryland contract violated the Supremacy Clause of the U.S. Constitution and was preempted. The Court decided that the compensation under the Maryland contract amounted to the MD PSC effectively setting the wholesale price when Congress had vested that authority in FERC, thus preempting state regulatory action to establish the wholesale price.

The New Jersey and Maryland decisions have been appealed to the United States Court of Appeals for the Third Circuit and the United States Court of Appeals for the Fourth Circuit, respectively. On January 24, 2014, the Company filed an amicus brief in the Third Circuit case in support of the petitioners and challenging the District Court ruling that the contracts violated the U.S. Constitution. On February 11, 2014, NRG filed a similar amicus brief in the Fourth Circuit. Briefing in both cases is ongoing.

New England

Performance Incentive Proposal — On January 17, 2014, ISO-NE filed at FERC to fundamentally revise its forward capacity market, or FCM, by making a resource's forward capacity market compensation dependent on resource output during short intervals of operating reserve scarcity. The ISO-NE proposal would replace the existing shortage event penalty structure with a new performance incentive, or PI, mechanism, resulting in capacity payments to resources that would be the combination of two components: (1) a base capacity payment and (2) a performance payment or charge. The performance payment or charge would be entirely dependent upon the resource's delivery of energy or operating reserves during scarcity conditions, and could be larger than the base payment.

NEPOOL, the ISO-NE stakeholder group, filed an alternative proposal to ISO-NE's PI proposal at FERC, under which the market rules would be revised to maintain the FCM capacity product as a tool to ensure resource adequacy, and would place real-time performance incentive-related improvements directly into the energy and reserve markets. The Company supports the NEPOOL alternative. The matter is pending at FERC.

FCM Rules for 2014 Forward Capacity Auction — On January 24, 2014, FERC accepted ISO-NE's proposal to revamp its Insufficient Supply and Insufficient Competition rules, which resulted in a declaration of the Insufficient Competition condition and a $7.025/kW-month price to all existing resources. Rehearing of the order remains pending.

New York

Demand Curve Reset — On November 29, 2013, the NYISO filed at FERC its triennial adjustment of its capacity market parameters for the 2014-2017 periods. The NYISO installed capacity requirement is determined by an administratively-set demand curve reflecting, among other things, the estimated net cost of new entry, or CONE, of a proxy generating unit. In its filing, the NYISO proposes to utilize a frame unit, without selective catalytic reduction, or SCR, for the Rest of State region, and a Frame unit with a SCR for Lower Hudson Valley, New York City and Long Island zones as its proxy generating unit. The use of this proxy unit is expected to decrease capacity prices in the New York City and Lower Hudson Valley zones. FERC accepted the filing on January 28, 2014, with a May 1, 2014 effective date for the new demand curves. The Company has filed for rehearing on certain aspects of FERC's rules.

NYSPSC Order Rescinding Danskammer Retirement — On October 29, 2013, the NYSPSC took emergency action to rescind its approval for the 530 MW Danskammer facility to retire on October 30, 2013. The NYSPSC's stated goal was to allow the facility to return to service in order to constrain rate increases in New York. The NYPSC approved the emergency Order and granted an extension until March 17, 2014 for Helios Capital LLC to file its plan to operate or retire the unit. The return to service of this facility may affect capacity prices received by NRG for its resources in the Rest-of-State capacity zone and the Lower Hudson Valley capacity zone.

Dunkirk Power LLC Reliability Service — On March 14, 2012, Dunkirk Power LLC, or Dunkirk Power, filed a notice with the NYSPSC of its intent to mothball the Dunkirk Station no later than September 10, 2012. The effects of the mothball on electric system reliability were reviewed by Niagara Mohawk Power Corporation, d/b/a National Grid, or NG. As a result of those studies, NG determined that the mothball of the Dunkirk Station would have a negative impact on the reliability of the New York transmission system and that portions of the Dunkirk Station may be retained for reliability purposes via a non-market compensation arrangement. On July 12, 2012, Dunkirk Power filed a RMR agreement with FERC. On July 20, 2012, NG and Dunkirk Power agreed on the material terms for a bilateral reliability support services, or RSS, agreement and submitted those terms to the NYSPSC for rate recovery in NG's rates. On August 16, 2012, the NYSPSC approved terms and on August 27, 2012, Dunkirk Power and NG entered into the RSS agreement that began on September 1, 2012 and expired on May 31, 2013. In late 2012, NG issued a request for proposals with respect to its reliability need in the Dunkirk area for the two years beginning June 1, 2014. Dunkirk Power submitted a proposal and signed a second, two-year, contract on March 4, 2013 pursuant to which one unit (Unit 2) at Dunkirk will continue operating through May 31, 2015. The contract was submitted to the NYSPSC in March 2013 and approved in May 2013.

Independent Power Producers of New York Complaint — On May 10, 2013, generators in New York filed a complaint at FERC against the NYISO. The generators asked FERC to direct the NYISO to require that capacity from existing generation resources that would have exited the market but for out-of-market payments under RMR type agreements be excluded from the capacity market altogether or be offered at levels no lower than the resources' going-forward costs. The generators point to the recent reliability services agreements entered into between the NYSPSC and generators, including Dunkirk Power, and seek to prevent below-cost offers from artificially suppressing prices in the New York Control Area Installed Capacity Spot Market Auction. A number of New York Transmission Owners protested the filing and the case is pending.

South Central Region

On July 5, 2013, AmerenEnergy Resources Generating Company, or Ameren, filed a complaint against MISO pertaining to the compensation for generators asked by MISO to provide service past their retirement date due to reliability concerns. Ameren asked FERC to require MISO to provide such generators their full cost of service as compensation and not merely cover the generator's incremental costs of operation going-forward costs. The Company supports the Ameren complaint. The matter remains pending.

ERCOT

At its September 12, 2013 open meeting, the PUCT directed ERCOT to implement an operating reserve demand curve by the summer of 2014, known as ORDC B+. ORDC B+ simulates real-time co-optimization and adjusts prices to reflect outcomes expected under real-time co-optimization. ERCOT continues to work on the system changes required to implement the ORDC B+ and it is expected to be in service on or near June 1, 2014. The demand curve will be set to achieve an imputed value of lost load of $9,000 per MWh when ERCOT operating reserves decrease to 2,000 MWs. As part of prior market reforms, system wide offer caps (currently $5,000) will increase to $7,000 per MWh in June 2014 and $9,000 per MWh in June 2015.

The PUCT is currently considering adoption of a mandatory reserve margin in order to remedy forecasted resource shortfalls and assure system reliability. On October 25, 2013, at the regular PUCT open meeting, two of the three commissioners expressed support for mandatory reserve margins although no formal vote was taken. In response to a PUCT posting of a number of policy questions, stakeholder comments were filed in late December 2013 regarding potential longer term market design changes, including forward capacity market elements. However, two recent developments have slowed the pace of the market design change discussion.

In January 2014, ERCOT disclosed its proposed revised load forecasting methodology, which projected lower peak demand growth in ERCOT. Also in January 2014, the Brattle Group released a report analyzing the economically optimal reserve margin, which identified the risk-neutral reserve margin as being 10.2%, and that the current market would support an 11.4% reserve margin. However Brattle's analysis also demonstrated that the ultimate customer cost of a capacity market, which would support the current ERCOT reliability standard (Brattle found would require a 14.1% reserve) is modest (approximately 1% impact to the customer cost) and that a capacity market is the most cost effective way to address the risk of blackouts due to substandard planning reserves.

Environmental Matters
NRG is subject to a wide range of environmental laws in the development, ownership, construction and operation of projects in the United States and Australia. These laws generally require governmental authorizations to build and operate power plants. Environmental laws have become increasingly stringent and NRG expects this trend to continue. The electric generation industry is likely to face new and more stringent requirements to address various emissions, including greenhouse gases, as well as combustion byproducts, water discharge and use, and threatened and endangered species. In general, the Company expects future laws to require adding emissions controls or other environmental controls or to impose more restrictions on the operations of the Company's facilities, which could have a material effect on operations.
Federal Environmental Initiatives
Environmental Regulatory Landscape — A number of regulations with the potential to affect the Company and its facilities are in development or under review by the EPA: NSPS for GHGs, NAAQS revisions and implementation, coal combustion byproducts regulation, effluent guidelines and once-through cooling regulations. While most of these regulations have been considered for some time, the outcomes and any resulting impact on NRG cannot be fully predicted until the rules are finalized (and any resulting legal challenges resolved).
Air
The CAA and the resulting regulations (as well as similar state and local requirements) have the potential to affect air emissions, operating practices and pollution control equipment required at power plants. Under the CAA, the EPA sets NAAQS for certain pollutants including SO_2, ozone, and $PM_{2.5}$. Many of the Company's facilities are located in or near areas that are classified by the EPA as not achieving certain NAAQS (non-attainment areas). The relevant NAAQS have become more stringent and NRG expects that trend to continue. The Company expects increased regulation at both the federal and state levels of its air emissions and maintains a comprehensive compliance strategy to address these continuing and new requirements. Complying with increasingly stringent NAAQS may require the installation of additional emissions control equipment at some NRG facilities or retiring of units if installing such controls is not economical. Significant changes to air regulatory programs affecting the Company are described below.
In January 2014, EPA re-proposed the NSPS for CO_2 emissions from new fossil-fuel-fired electric generating units that had been previously proposed in April 2012. The re-proposed standards are 1,000 pounds of CO_2 per MWh for large gas units and 1,100 pounds of CO_2 per MWh for coal units and small gas units. Proposed standards are in effect until a final rule is published or another rule is re-proposed. In 2014, EPA intends to propose another rule that would require states to develop CO_2 standards that would apply to existing fossil-fueled generating facilities.
The effects from federal, regional or state regulation of GHGs on the Company's financial performance will depend on a number of factors, including the regulatory design, level of GHG reductions, the availability of offsets, and the extent to which NRG would be entitled to receive CO_2 emissions credits without having to purchase them in an auction or on the open market. Thereafter, under any such legislation or regulation, the impact on NRG would depend on the Company's level of success in developing and deploying low and no carbon technologies.

CO2 Emissions

NRG emits CO_2 when generating electricity at most of its facilities. The graph presented below illustrates NRG's emissions of CO_2 for 2011, 2012, and 2013. NRG anticipates reductions in its future emissions profile as the Company adds more renewable sources such as wind and solar, modernizes the fleet through repowering, improves generation efficiencies, and explores methods to capture CO_2.

Cross-State Air Pollution Rule — In 2005, the EPA promulgated CAIR which established SO_2 and NO_x cap-and-trade programs applicable directly to states and indirectly to generating facilities in the eastern United States. In July 2008, the U.S. Court of Appeals for the D.C. Circuit in State of North Carolina v. Environmental Protection Agency issued an opinion that would have vacated CAIR. In December 2008, the U.S. Court of Appeals for the D.C. Circuit issued a second opinion that simply remanded the case to the EPA without vacating CAIR.

In August 2011, the EPA finalized CSAPR, which was intended to replace CAIR starting in 2012. It was designed to address interstate SO_2 and NO_X emissions from certain power plants in the eastern half of the United States. In September 2011, GenOn and others asked the U.S. Court of Appeals for the D.C. Circuit to stay and vacate CSAPR because, among other reasons, the rule circumvented the state implementation plan process expressly provided for in the CAA, afforded affected parties no time to install compliance equipment before the compliance period started and included numerous material changes from the proposed rule, which deprived parties of an opportunity to provide comments. In December 2011, the court issued an order that stayed implementation of CSAPR and ordered EPA to keep CAIR in place until the court could rule on the legal deficiencies alleged with respect to CSAPR. In August 2012, the D.C. Circuit Court issued an order vacating CSAPR and keeping CAIR in place. The EPA petitioned the U.S. Supreme Court seeking review of the D.C. Circuit's decision, which petition was granted. The Supreme Court held oral argument on this case on December 10, 2013.

Byproducts, Wastes, Hazardous Materials and Contamination

In June 2010, the EPA proposed two alternatives for regulating byproducts of coal combustion (e.g., ash and gypsum) under the RCRA. Under the first proposal, these byproducts would be regulated as solid wastes. Under the second proposal, these byproducts would be regulated as “special wastes” in a manner similar to the regulation of hazardous waste with an exception for certain types of beneficial use of these byproducts. The second alternative would impose significantly more stringent requirements on and increase materially the cost of disposal of coal combustion byproducts. In January 2014, the EPA signed a consent decree that, if entered by the court, would obligate the EPA to decide the manner in which these coal combustion byproducts will be regulated by December 2014.

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products at the facility. NRG may also be responsible for property damage, personal injury and investigation and remediation costs incurred by a party in connection with hazardous material releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended by the Superfund Amendments and Reauthorization Act of 1986, or SARA, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and the courts have interpreted liability under such laws to be strict (without fault) and joint and several. Cleanup obligations can often be triggered during the closure or decommissioning of a facility, in addition to spills during its operations. Further discussions of affected NRG sites can be found in Item 15 — Note 24, Environmental Matters, to the Consolidated Financial Statements.

Nuclear Waste — The federal government's program to construct a nuclear waste repository at Yucca Mountain, Nevada was discontinued in 2010. In order to meet the federal government's obligations to safely manage spent nuclear fuel, or SNF, and high-level radioactive waste, or HLW, under the U.S. Nuclear Waste Policy Act of 1982, or the Act, the U.S. DOE established a blue ribbon commission to explore alternatives. Also consistent with the Act, owners of nuclear plants, including the owners of STP, entered into contracts setting out the obligations of the owners and the U.S. DOE, including the fees to be paid by the owners for the U.S. DOE's services. Since 1998, the U.S. DOE has been in default on its obligations to begin removing SNF and HLW from reactors, necessitating each site to take steps to construct interim spent fuel storage installations.

On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing. On the same date, as ordered by the court, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero, subject to any further judicial decision. The DOE’s submitted proposal becomes effective after the 90-days of continuous session of the Congress unless there is Congressional action contrary to the DOE proposal. However, if the court grants the petition for rehearing, the proposal to eliminate the fee (and the review period) will be held in suspense until after the court rules. Until such time as a new fee structure is in effect, STPNOC must continue to pay the current SNF disposal fees.

On February 5, 2013, STPNOC entered into a settlement agreement with the U.S. DOE for payment of damages relating to the U.S. DOE's failure to accept SNF and HLW under the Act through December 31, 2013, which was extended through an addendum dated January 24, 2014 to December 31, 2016. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. STPNOC currently stores all SNF generated by its nuclear generating facilities in on-site storage pools. Since STPNOC's SNF storage pools do not have sufficient storage capacity for the life of the units, STPNOC plans to construct dry cask storage capability on-site. STPNOC plans to continue to assert claims against the U.S. DOE for damages relating to the U.S. DOE's failure to accept SNF and HLW.

The NRC’s temporary storage rule, known as the “waste confidence decision,” recognizes that licensees can safely store SNF at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. However, in June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC’s temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. In September 2012, the NRC directed NRC Staff to complete a generic environmental impact statement and to revise the temporary storage rule which is now not expected until October 2014.

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. STP's warehouse capacity is adequate for on-site storage until a site in Andrews County, Texas becomes fully operational.

Water

Clean Water Act — The Company is required under the CWA to comply with intake and discharge requirements, requirements for technological controls and operating practices. As with air quality regulations, federal and state water regulations are expected to impose additional and more stringent requirements or limitations in the future. This includes requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the CWA (the 316(b) regulations). In April 2011, the EPA proposed a 316(b) rule that would apply to the Company's existing facilities that use cooling water intake structures to withdraw water from waters of the United States. That proposal would impose national standards for reducing mortality from impingement and entrainment of organisms. The final rule may differ from the proposal as a result of the public comment process. California and New York already have promulgated their own more stringent requirements for once-through cooled units, which may satisfy the requirements of the expected revised 316(b) Rule. NRG expects to comply with the anticipated requirements with a mix of intake and operational modifications.

Regional Environmental Issues

East Region

The EPA and various states have been investigating compliance of electric generating facilities with the pre-construction permitting requirements of the CAA known as "new source review," or NSR. In January 2009, GenOn received an NOV from the EPA alleging that past work at Keystone, Portland and Shawville generating facilities violated regulations regarding NSR. In June 2011, GenOn received an NOV from the EPA alleging that past work at Avon Lake and Niles generating stations violated NSR. In December 2007, the NJDEP filed suit alleging that NSR violations occurred at the Portland generating station, which suit was resolved pursuant to a July 2013 Consent Decree. Additionally, in April 2013, the Connecticut Department of Energy and Environmental Protection issued four NOVs alleging that past work at oil-fired combustion turbines at the Torrington Terminal, Franklin, Branford and Middletown violated regulations regarding NSR.

In 2008, the PADEP issued an NOV related to the inactive Monarch mine where low-volume wastewater from the Cheswick Generating Station and ash leachate were historically disposed. Resolution of the NOV could result in operational requirements such as pumping a minimum volume of water from the mine and a penalty of approximately $200,000.

In January 2006, NRG's Indian River Operations, Inc. was notified that it may be a potentially responsible party with respect to Burton Island Old Ash Landfill, a historic captive landfill located at the Indian River facility. On October 1, 2007, NRG signed an agreement with DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, DNREC issued findings that no further action is required in relation to surface water and that a previously planned shoreline stabilization project would satisfactorily address shoreline erosion. The landfill itself required a Remedial Investigation and Feasibility Study to determine the type and scope of any additional required work. The DNREC approved the Feasibility Study in December 2012. In January 2013, DNREC proposed a remediation plan based on the Feasibility Study. The remediation plan was approved in October 2013. The cost of completing the work required by the approved remediation plan is consistent with amounts previously budgeted. On May 29, 2008, DNREC requested that NRG's Indian River Operations, Inc. participate in the development and performance of a Natural Resource Damage Assessment at the Burton Island Old Ash Landfill. NRG is currently working with DNREC and other trustees to close out the assessment process.

The MDE sued two of the GenOn's subsidiaries, NRG MD Ash and GenOn Mid-Atlantic, for alleged violations of water pollution laws at three fly ash disposal sites in Maryland: Faulkner (2008/2011), Brandywine (2010) and Westland (2012). On April 30, 2013, the court approved the consent decree resolving these issues.

MDE has announced that it intends to promulgate more stringent regulations regarding NO_x emissions, which could negatively affect some of the Company's coal units in Maryland.

The Company operates generating units in Connecticut, Delaware, Maryland, Massachusetts, and New York that are subject to RGGI, which is a regional cap and trade system. In 2013, each of these states finalized a rule that reduced and will continue to reduce the number of allowances, which the Company believes will increase the price of each allowance. These new rules could adversely impact NRG's results of operations, financial condition and cash flows.

South Central Region

In 2009, the U.S. DOJ, on behalf of the EPA, and later the Louisiana Department of Environmental Quality on behalf of the state of Louisiana, sued LaGen in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. On March 6, 2013, the court entered a Consent Decree resolving the matter. In addition to a fine of $3.5 million and mitigation projects totaling $10.5 million, the Consent Decree includes: (i) annual emission caps for NO_x and SO_2; (ii) installation of selective non-catalytic reduction on Units 1, 2 and 3 by May 1, 2014; (iii) installation of dry sorbent injection on Unit 1 by April 15, 2015 followed by a further reduction in SO_2 in March 2025; (iv) conversion of Unit 2 to natural gas; and (v) surrender of any excess allowances associated with the NRG owned portion of the plant. For further discussion of this matter, refer to Note 22, Commitments and Contingencies.

Environmental Capital Expenditures

Based on current (and in some cases proposed) rules, technology and preliminary plans based on some proposed rules, NRG estimates that environmental capital expenditures from 2014 through 2018 required to comply with environmental laws will be approximately $332 million which includes $120 million for GenOn. These costs are primarily associated with (i) controls to satisfy MATS and recent NSR settlement at Big Cajun II; (ii) controls to satisfy MATS at W.A. Parish, Limestone and Conemaugh; and (iii) NO_x controls for Sayreville and Gilbert. In addition, in connection with the proposed acquisition of EME, the Company expects to incur additional environmental capital expenditures. NRG continues to explore cost-effective compliance alternatives to further reduce costs.

NRG's current contracts with the Company's rural electrical customers in the South Central region allow for recovery of a portion of the region's capital costs once in operation, along with a capital return incurred by complying with any change in law, including interest over the asset life of the required expenditures. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

Employees

As of December 31, 2013, NRG had 7,786 employees, approximately 35.9% of whom were covered by U.S. bargaining agreements. During 2013, the Company did not experience any labor stoppages or labor disputes at any of its facilities.

Available Information

NRG's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's website, www.nrgenergy.com, as soon as reasonably practicable after they are electronically filed with, or furnished to, the SEC. The Company also routinely posts press releases, presentations, webcasts, and other information regarding the Company on the Company's website.

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

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

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

NRG's financial performance may be impacted by changing natural gas prices, significant and unpredictable price fluctuations in the wholesale power markets and other market factors that are beyond the Company's control.

A significant percentage of the Company's domestic revenues are derived from baseload power plants that are fueled by coal. In many of the competitive markets where NRG operates, the price of power typically is set by natural gas-fired power plants that have traditionally had higher variable costs than NRG's coal-fired power plants. Historically, this has allowed the Company's coal generation assets to earn attractive operating margins compared to plants fueled by natural gas. Decreases in natural gas prices have resulted in a corresponding decrease in the market price of power that has significantly reduced the operating margins of the Company's baseload generation assets and may materially and adversely impact its financial performance. At low enough natural gas prices, gas plants become more economical than coal generation. In such a price environment, the Company's coal units cycle more often or even shut down until prices or load increases enough to justify running them again.

In addition, because changes in power prices in the markets where NRG operates are generally correlated with changes in natural gas prices, NRG's hedging portfolio includes natural gas derivative instruments to hedge power prices for its coal and nuclear generation. If this correlation between power prices and natural gas prices is not maintained and a change in gas prices is not proportionately offset by a change in power prices, the Company's natural gas hedges may not fully cover this differential. This could have a material adverse impact on the Company's cash flow and financial position.

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

- changes in generation capacity in the Company's markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation plants, expansion of existing plants or additional transmission capacity;
- electric supply disruptions, including plant outages and transmission disruptions;
- changes in power transmission infrastructure;
- fuel transportation capacity constraints;
- weather conditions;
- changes in the demand for power or in patterns of power usage, including the potential development of demand-side management tools and practices, distributed generation, and more efficient end-use technologies;
- development of new fuels and new technologies for the production of power;
- development of new technologies for the production of natural gas;
- regulations and actions of the ISOs; and
- federal and state power market and environmental regulation and legislation.

Such factors have affected the Company's wholesale power operating results in the past and will continue to do so in the future.

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

NRG relies on coal, oil and natural gas to fuel a majority of its power generation facilities. Delivery of these fuels to the facilities is dependent upon the continuing financial viability of contractual counterparties as well as upon the infrastructure (including rail lines, rail cars, barge facilities, roadways, riverways and natural gas pipelines) available to serve each generation facility. As a result, the Company is subject to the risks of disruptions or curtailments in the production of power at its generation facilities if no fuel is available at any price or if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure.

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

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

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

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

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

A substantial portion of the output from NRG's coal and nuclear facilities has been sold forward under fixed price power sales contracts through 2014 and the Company also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so. Because the obligations under most of these agreements are not contingent on a unit being available to generate power, NRG is generally required to deliver power to the buyer, even in the event of a plant outage, fuel supply disruption or a reduction in the available capacity of the unit. To the extent that the Company does not have sufficient lower cost capacity to meet its commitments under its forward sale obligations, the Company would be required to supply replacement power either by running its other, higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. If NRG fails to deliver the contracted power, it would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

In the South Central region, NRG has long-term contracts with rural cooperatives that require it to serve all of the cooperatives' requirements at prices that generally reflect the costs of coal-fired generation. On December 19, 2013, the Entergy region joined the MISO. The MISO employs a two settlement market. It is impossible to predict how the price NRG is required to pay to serve its cooperative customers may change as a result of the MISO integration. During limited peak demand periods, the load requirements of these contract customers exceed the capacity of NRG's coal-fired Big Cajun II plant. During such peak demand periods, NRG may not have sufficient generation to self-supply its cooperative customers' needs and may be exposed to locational market pricings. NRG's financial returns from its South Central region could be negatively impacted for a limited period if the cost of power is at higher prices than can be recovered under the Company's contracts.

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

The Company typically enters into hedging agreements, including contracts to purchase or sell commodities at future dates and at fixed prices, in order to manage the commodity price risks inherent in its power generation operations. These activities, although intended to mitigate price volatility, expose the Company to other risks. When the Company sells power forward, it gives up the opportunity to sell power at higher prices in the future, which not only may result in lost opportunity costs but also may require the Company to post significant amounts of cash collateral or other credit support to its counterparties. The Company also relies on counterparty performance under its hedging agreements and is exposed to the credit quality of its counterparties under those agreements. Further, if the values of the financial contracts change in a manner that the Company does not anticipate, or if a counterparty fails to perform under a contract, it could harm the Company's business, operating results or financial position.

NRG does not typically hedge the entire exposure of its operations against commodity price volatility. To the extent it does not hedge against commodity price volatility, the Company's results of operations and financial position may be improved or diminished based upon movement in commodity prices.

NRG may engage in trading activities, including the trading of power, fuel and emissions allowances that are not directly related to the operation of the Company's generation facilities or the management of related risks. These trading activities take place in volatile markets and some of these trades could be characterized as speculative. The Company would expect to settle these trades financially rather than through the production of power or the delivery of fuel. This trading activity may expose the Company to the risk of significant financial losses which could have a material adverse effect on its business and financial condition.

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

The Company is exposed to market risks through its power marketing business, which involves the sale of energy, capacity and related products and the purchase and sale of fuel, transmission services and emission allowances. These market risks include, among other risks, volatility arising from location and timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

NRG undertakes these marketing activities through agreements with various counterparties. Many of the Company's agreements with counterparties include provisions that require the Company to provide guarantees, offset of netting arrangements, letters of credit, a first lien on assets and/or cash collateral to protect the counterparties against the risk of the Company's default or insolvency. The amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in the Company being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of the Company's strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than the Company anticipates or will be able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as a cash margin, the Company may not be able to manage price volatility effectively or to implement its strategy. An increase in the amount of letters of credit or cash collateral required to be provided to the Company's counterparties may negatively affect the Company's liquidity and financial condition. Further, if any of NRG's facilities experience unplanned outages, the Company may be required to procure replacement power at spot market prices in order to fulfill contractual commitments. Without adequate liquidity to meet margin and collateral requirements, the Company may be exposed to significant losses, may miss significant opportunities, and may have increased exposure to the volatility of spot markets.

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

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

NRG generally attempts to balance its fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for in accordance with the Financial Accounting Standards Board, or FASB, ASC 815, Derivatives and Hedging, or ASC 815, which requires the Company to record all derivatives on the balance sheet at fair value with changes in the fair value resulting from fluctuations in the underlying commodity prices immediately recognized in earnings, unless the derivative qualifies for cash flow hedge accounting treatment. Whether a derivative qualifies for cash flow hedge accounting treatment depends upon it meeting specific criteria used to determine if the cash flow hedge is and will remain appropriate for the term of the derivative. All economic hedges may not necessarily qualify for cash flow hedge accounting treatment. As a result, the Company's quarterly and annual results are subject to significant fluctuations caused by changes in market prices.

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

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

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

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

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

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

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

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

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

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

NRG cannot be certain of the level of capital expenditures that will be required due to changing environmental and safety laws (including changes in the interpretation or enforcement thereof), needed facility repairs and unexpected events (such as natural disasters or terrorist attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on the Company's liquidity and financial condition.

If NRG significantly modifies a unit, the Company may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under the new source review provisions of the federal Clean Air Act, which would likely result in substantial additional capital expenditures.

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

The Company is developing or constructing new generation facilities improving its existing facilities; and adding environmental controls to its existing facilities. The development, construction, expansion, modification and refurbishment of power generation facilities involve many additional risks, including:

- inability to receive U.S. DOE loan guarantees, funding or cash grants;
- delays in obtaining necessary permits and licenses;
- inability to sell down interests in a project or develop successful partnering relationships;
- environmental remediation of soil or groundwater at contaminated sites;
- interruptions to dispatch at the Company's facilities;
- supply interruptions;
- work stoppages;
- labor disputes;
- weather interferences;
- unforeseen engineering, environmental and geological problems;
- unanticipated cost overruns;
- exchange rate risks; and
- failure of contracting parties to perform under contracts, including EPC contractors.

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Any of these risks could cause NRG's financial returns on new investments to be lower than expected, or could cause the Company to operate below expected capacity or availability levels, which could result in lost revenues, increased expenses, higher maintenance costs and penalties. Insurance is maintained to protect against these risks, warranties are generally obtained for limited periods relating to the construction of each project and its equipment in varying degrees, and contractors and equipment suppliers are obligated to meet certain performance levels. The insurance, warranties or performance guarantees, however, may not be adequate to cover increased expenses. As a result, a project may cost more than projected and may be unable to fund principal and interest payments under its construction financing obligations, if any. A default under such a financing obligation could result in the Company losing its interest in a power generation facility.

Furthermore, where the Company has partnering relationships with a third party, the Company is subject to the viability and performance of the third party. The Company's inability to find a replacement contracting party, particularly an EPC contractor, where the original contracting party has failed to perform, could result in the abandonment of the development and/or construction of such project, while the Company could remain obligated on other agreements associated with the project, including PPAs.

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

NRG and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance.

NRG and its subsidiaries have issued certain guarantees of the performance of others, which obligate NRG and its subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by the third parties, NRG could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Company.

The Company's development programs are subject to financing and public policy risks that could adversely impact NRG's financial performance or result in the abandonment of such development projects.

While NRG currently intends to develop and finance the more capital intensive projects on a non-recourse or limited recourse basis through separate project financed entities, and intends to seek additional investments in most of these projects from third parties, NRG anticipates that it will need to make significant equity investments in these projects. NRG may also decide to develop and finance some of the projects, such as smaller gas-fired and renewable projects, using corporate financial resources rather than non-recourse debt, which could subject NRG to significant capital expenditure requirements and to risks inherent in the development and construction of new generation facilities. In addition to providing some or all of the equity required to develop and build the proposed projects, NRG's ability to finance these projects on a non-recourse basis is contingent upon a number of factors, including the terms of the EPC contracts, construction costs, PPAs and fuel procurement contracts, capital markets conditions, the availability of tax credits and other government incentives for certain new technologies. To the extent NRG is not able to obtain non-recourse financing for any project or should the credit rating agencies attribute a material amount of the project finance debt to NRG's credit, the financing of the development projects could have a negative impact on the credit ratings of NRG.

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

Furthermore, the viability of the Company's renewable development projects are largely contingent on public policy mechanisms including production and investment tax credits, cash grants, loan guarantees, accelerated depreciation tax benefits, renewable portfolio standards, or RPS, and carbon trading plans. These mechanisms have been implemented at the state and federal levels to support the development of renewable generation, demand-side and smart grid, and other clean infrastructure technologies. The availability and continuation of public policy support mechanisms will drive a significant part of the economics and viability of the Company's development program and expansion into clean energy investments.

Supplier and/or customer concentration at certain of NRG's facilities may expose the Company to significant financial credit or performance risks.
NRG often relies on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of certain of its facilities. If these suppliers cannot perform, the Company utilizes the marketplace to provide these services. There can be no assurance that the marketplace can provide these services as, when and where required or at comparable prices.
At times, NRG relies on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. The Company has also hedged a portion of its exposure to power price fluctuations through forward fixed price power sales and natural gas price swap agreements. Counterparties to these agreements may breach or may be unable to perform their obligations. NRG may not be able to enter into replacement agreements on terms as favorable as its existing agreements, or at all. If the Company was unable to enter into replacement PPAs, the Company would sell its plants' power at market prices. If the Company is unable to enter into replacement fuel or fuel transportation purchase agreements, NRG would seek to purchase the Company's fuel requirements at market prices, exposing the Company to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price.
The failure of any supplier or customer to fulfill its contractual obligations to NRG could have a material adverse effect on the Company's financial results. Consequently, the financial performance of the Company's facilities is dependent on the credit quality of, and continued performance by, suppliers and customers.
NRG relies on power transmission facilities that it does not own or control and that are subject to transmission constraints within a number of the Company's core regions. If these facilities fail to provide NRG with adequate transmission capacity, the Company may be restricted in its ability to deliver wholesale electric power to its customers and the Company may either incur additional costs or forego revenues. Conversely, improvements to certain transmission systems could also reduce revenues.
NRG depends on transmission facilities owned and operated by others to deliver the wholesale power it sells from the Company's power generation plants to its customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate, NRG's ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, the Company's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. The Company cannot also predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.
In addition, in certain of the markets in which NRG operates, energy transmission congestion may occur and the Company may be deemed responsible for congestion costs if it schedules delivery of power between congestion zones during times when congestion occurs between the zones. If NRG were liable for such congestion costs, the Company's financial results could be adversely affected.
The Company has a significant amount of generation located in load pockets, making that generation valuable, particularly with respect to maintaining the reliability of the transmission grid. Expansion of transmission systems to reduce or eliminate these load pockets could negatively impact the value or profitability of the Company's existing facilities in these areas.
One of our subsidiaries is a publicly traded corporation, NRG Yield, Inc., which may involve a greater exposure to legal liability than our historic business operations.
One of our subsidiaries is NRG Yield, Inc., a publicly traded corporation. Our controlling interest in NRG Yield, Inc. and the position of certain of our executive officers on the Board of NRG Yield, Inc. may increase the possibility of claims of breach of fiduciary duties including claims of conflicts of interest related to NRG Yield, Inc.. Any liability resulting from such claims could have a material adverse effect on our future business, financial condition, results of operations and cash flows.

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

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

NRG may be unable to integrate the operations of acquired entities in the manner expected.

NRG enters into acquisitions that result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of these acquisitions depends on whether the businesses can be integrated into NRG in an efficient and effective manner. The integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of NRG's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the Company's ability to achieve the anticipated benefits of the acquisitions. NRG may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect NRG's future business, financial condition, operating results and prospects.

Future acquisition activities may have adverse effects.

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

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

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

Public utilities under the FPA are required to obtain FERC acceptance of their rate schedules for wholesale sales of electricity. Except for ERCOT generating facilities and power marketers, all of NRG's non-qualifying facility generating companies and power marketing affiliates in the U.S. make sales of electricity in interstate commerce and are public utilities for purposes of the FPA. The FERC has granted each of NRG's generating and power marketing companies that make sales of electricity outside of ERCOT the authority to sell electricity at market-based rates. The FERC's orders that grant NRG's generating and power marketing companies market-based rate authority reserve the right to revoke or revise that authority if the FERC subsequently determines that NRG can exercise market power in transmission or generation, create barriers to entry, or engage in abusive affiliate transactions. In addition, NRG's market-based sales are subject to certain market behavior rules, and if any of NRG's generating and power marketing companies were deemed to have violated one of those rules, they are subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of their market-based rate authority. If NRG's generating and power marketing companies were to lose their market-based rate authority, such companies would be required to obtain the FERC's acceptance of a cost-of-service rate schedule and could become subject to the accounting, record-keeping, and reporting requirements that are imposed on utilities with cost-based rate schedules. This could have an adverse effect on the rates NRG charges for power from its facilities.

NRG is also affected by legislative and regulatory changes, as well as changes to market design, market rules, tariffs, cost allocations, and bidding rules that occur in the existing ISOs. The ISOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, mitigation, including price limitations, offer caps, and other mechanisms to address some of the volatility and the potential exercise of market power in these markets. These types of price limitations and other regulatory mechanisms may have an adverse effect on the profitability of NRG's generation facilities that sell energy and capacity into the wholesale power markets.

The regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale and retail competition and the creation of incentives for the addition of large amounts of new renewable generation and, in some cases, transmission. These changes are ongoing and the Company cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on NRG's business. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism, as well as proposals to re-regulate the markets or require divestiture by generating companies to reduce their market share. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, the Company's business prospects and financial results could be negatively impacted.

NRG continuously monitors the ongoing efforts of the CFTC to implement the Dodd-Frank Act and to otherwise revise the rules and regulations applicable to the futures and over-the-counter derivatives markets. The CFTC’s remaining efforts in this regard concern, among other things, the implementation of the Volcker rule and of other new rules relating to margin collateral and position limits for futures and other derivatives. Such changes could negatively impact NRG’s ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially limiting NRG’s ability to utilize liens as collateral for derivatives transactions and decreasing liquidity in the forward commodity and derivatives markets. The Company expects that, in 2014, the CFTC will further clarify the scope of the Dodd-Frank Act and issue additional final rules.

Government regulations providing incentives for renewable generation could change at any time and such changes may adversely impact our business, revenues, margins, results of operations and cash flows.

The Company's growth strategy depends in part on government policies that support renewable generation and enhance the economic viability of owning renewable electric generation assets. Renewable generation assets currently benefit from various federal, state and local governmental incentives such as ITCs, cash grants in lieu of ITCs, loan guarantees, RPS programs, modified accelerated cost-recovery system of depreciation and bonus depreciation. For example, the U.S. Internal Revenue Code of 1986, as amended, provides an ITC of 30% of the cost-basis of an eligible resource, including solar energy facilities placed in service prior to the end of 2016, which percentage is currently scheduled to be reduced to 10% for solar energy systems placed in service after December 31, 2016.

Many states have adopted RPS programs mandating that a specified percentage of electricity sales come from eligible sources of renewable energy. However, the regulations that govern the RPS programs, including pricing incentives for renewable energy, or reasonableness guidelines for pricing that increase valuation compared to conventional power (such as a projected value for carbon reduction or consideration of avoided integration costs), may change. If the RPS requirements are reduced or eliminated, it could lead to fewer future power contracts or lead to lower prices for the sale of power in future power contracts, which could have a material adverse effect on the Company's future growth prospects.

Such material adverse effects may result from decreased revenues, reduced economic returns on certain project company investments, increased financing costs, and/or difficulty obtaining financing. Furthermore, the ARRA included incentives to encourage investment in the renewable energy sector, such as cash grants in lieu of ITCs, bonus depreciation and expansion of the U.S. DOE loan guarantee program. It is uncertain what loan guarantees may be made by the U.S. DOE loan guarantee program in the future. In addition, the cash grant in lieu of ITCs program only applies to facilities that commenced construction prior to December 31, 2011, which commencement date may be determined in accordance with the safe harbor if more than 5% of the total cost of the eligible property was paid or incurred by December 31, 2011.

If the Company is unable to utilize various federal, state and local government incentives to acquire additional renewable assets in the future, or the terms of such incentives are revised in a manner that is less favorable to the Company, it may suffer a material adverse effect on the business, financial condition, results of operations and cash flows.

A significant reduction or elimination of government subsidies under the 1603 Cash Grant Program may have a material adverse effect on the Company's existing operations and may reduce the Company's cash flows. The ARRA section 1603 Cash Grant Program provides a cash payment from the federal government in lieu of ITCs for eligible renewable generation sources for which construction commenced prior to December 31, 2011, which commencement date may be determined in accordance with the 5% safe harbor. The amount of the 1603 Cash Grant Proceeds received is based on an application filed with the U.S. Treasury Department after a facility has reached COD. The applications are reviewed by, and are subject to approval of, the U.S. Treasury Department. In addition, the U.S. Treasury Department has said that it may reduce the amount of an applicant's cash grant award in cases where project costs exceed certain per watt cost benchmarks or in cases where project costs exceed certain percentage thresholds. The amount of 1603 Cash Grant Proceeds that the Company actually receives may differ materially from the amount expected and/or may be received at a later time than expected. On March 1, 2013, the federal sequestration went into effect, and, as a result, 1603 Cash Grant Proceeds for approved applications through September 30, 2013 were subject to an 8.7% reduction and approved applications after September 30, 2013 were subject to a 7.2% reduction.

As of December 31, 2013, the Company had outstanding applications for cash grants with the U.S Treasury in the aggregate amount of $539 million (net of sequestration). In January 2014, the U.S. Treasury Department awarded cash grants on the CVSR project of $307 million ($285 million net of sequestration), which is approximately 75% of the cash grant amount for which the Company had applied. In addition, in January 2014, the U.S. Treasury Department awarded cash grants on the Alpine project of $72 million ($66 million net of sequestration). As of the date hereof, NRG has outstanding with the U.S. Treasury Department applications for cash grants in the aggregate amount of $93 million, of which the Company expects to receive $86 million net of sequestration.

If the Company does not receive the expected 1603 Cash Grant Proceeds, or if the U.S. Treasury Department approves awards for amounts materially less than the amounts for which the Company has applied, our financial position could be materially adversely affected. Additionally, reductions in or eliminations or expirations of, the 1603 Cash Grant Program, or the U.S. Treasury Department's rejection of the Company's applications for cash grants could also have a material adverse effect on our business, financial condition, results of operations and cash flows.

NRG's long-term contracts may be challenged or declared invalid by a court of competent jurisdiction.

A significant portion of NRG’s revenues are derived from long-term bilateral contracts. Those contracts may be subject to challenge under a variety of legal doctrines. If NRG’s contracts were to be declared invalid, profitability may suffer and the Company would be exposed to increased merchant market risk.

NRG's ownership interest in a nuclear power facility subjects the Company to regulations, costs and liabilities uniquely associated with these types of facilities.

Under the Atomic Energy Act of 1954, as amended, or AEA, ownership and operation of STP, of which NRG indirectly owns a 44% interest, is subject to regulation by the NRC. Such regulation includes licensing, inspection, enforcement, testing, evaluation and modification of all aspects of nuclear reactor power plant design and operation, environmental and safety performance, technical and financial qualifications, decommissioning funding assurance and transfer and foreign ownership restrictions. The current facility operating licenses for STP expire on August 20, 2027 (Unit 1) and December 15, 2028 (Unit 2). STP has applied for the renewal of such licenses for a period of 20 years beyond the expirations of the current licenses. The NRC may decline to issue such renewals or may modify or otherwise condition such license renewals in a manner that results in substantial increased capital or operating costs, or that otherwise results in a material adverse effect on STP’s economics and NRG’s results of operations, financial condition or cash flow.

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. The on-going industry response to the accident at Fukushima is an example of an external event with the potential for requiring significant increases in capital expenditures in order to comply with the yet-to-be-determined consequences of, and regulatory response to, an adverse event, such as mitigating steps that might be required after the seismic re-analysis in progress at all nuclear generating facilities. Additionally, aging equipment may require more capital expenditures to keep each of these nuclear power plants operating efficiently. This equipment is also 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. STP will be obligated to continue storing spent nuclear fuel if the U.S. DOE continues to fail to meet its contractual obligations to STP made pursuant to the U.S. Nuclear Waste Policy Act of 1982 to accept and dispose of STP's spent nuclear fuel. See also Item 1 — Regulatory Matters - Nuclear Operations- Decommissioning Trusts and Item 1 — Environmental Matters — U.S. Federal Environmental Initiatives — Nuclear Waste for further discussion. Costs associated with these risks could be substantial and could have a material adverse effect on NRG's results of operations, financial condition or cash flow to the extent not covered by the Decommissioning Trusts or recovered from ratepayers. In addition, to the extent that all or a part of STP is required by the NRC to permanently or temporarily shut down or modify its operations, or is otherwise subject to a forced outage, NRG may incur additional costs to the extent it is obligated to provide power from more expensive alternative sources — either NRG's own plants, third party generators or the ERCOT — to cover the Company's then existing forward sale obligations. Such shutdown or modification could also lead to substantial costs related to the storage and disposal of radioactive materials and spent nuclear fuel.

While STP maintains property and liability insurance for losses related to nuclear operations, there may be limitations on the amounts and types of insurance commercially available. See also Item 15 — Note 22, Commitments and Contingencies, Nuclear Insurance. An accident at STP or another nuclear facility could have a material adverse effect on NRG's financial condition, its operational results, or liquidity as losses may exceed the insurance coverage available and/or may result in the obligation to pay retrospective premium obligations.

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

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

Policies at the national, regional and state levels to regulate GHG emissions, as well as climate change, could adversely impact NRG's results of operations, financial condition and cash flows.

NRG's GHG emissions for 2013 can be found in Item 1, Business - Environmental Matters. The impact of further legislation or regulation of GHGs on the Company's financial performance will depend on a number of factors, including the level of GHG standards, the extent to which mitigation is required, the availability of offsets, and the extent to which NRG would be entitled to receive CO_2 emissions credits without having to purchase them in an auction or on the open market.

The Company operates generating units in Connecticut, Delaware, Maryland, Massachusetts, and New York that are subject to RGGI, which is a regional cap and trade system. In 2013, each of these states finalized a rule that reduced and will continue to reduce the number of allowances, which the Company believes will increase the price of each allowance. These new rules could adversely impact NRG's results of operations, financial condition and cash flows. California has a CO_2 cap and trade program for electric generating units greater than 25 MW. The impact on the Company depends on the cost of the allowances and the ability to pass these costs through to customers.

In January 2014, the EPA re-proposed the NSPS for CO_2 emissions from new fossil-fuel-fired electric generating units that had been previously proposed in April 2012. The re-proposed standards are 1,000 pounds of CO_2 per MWh for large gas units and 1,100 pounds of CO_2 per MWh for coal units and small gas units. Proposed standards are in effect until a final rule is published or another rule is re-proposed. In 2014, the EPA intends to propose another rule that would require states to develop CO_2 standards that would apply to existing fossil-fueled generating facilities. These rules could adversely impact NRG's results of operations, financial condition and cash flows.

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

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

As of December 31, 2013, approximately 58.8% of NRG's employees at its U.S. generation plants were covered by collective bargaining agreements. In the event that the Company's union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, NRG would be responsible for procuring replacement labor or the Company could experience reduced power generation or outages. NRG's ability to procure such labor is uncertain. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on the Company's business, financial condition, results of operations and cash flow. In addition, a number of the Company's employees at NRG's plants are close to retirement. The Company's inability to replace those workers could create potential knowledge and expertise gaps as those workers retire.

Changes in technology may impair the value of NRG's power plants.

Research and development activities are ongoing to provide alternative and more efficient technologies to produce power, including "clean" coal and coal gasification, wind, photovoltaic (solar) cells, energy storage, and improvements in traditional technologies and equipment, such as more efficient gas turbines. Advances in these or other technologies could reduce the costs of power production to a level below what the Company has currently forecasted, which could adversely affect its cash flow, results of operations or competitive position.

Risks that are beyond NRG's control, including but not limited to acts of terrorism or related acts of war, natural disaster, hostile cyber intrusions or other catastrophic events could have a material adverse effect on NRG's financial condition, results of operations and cash flows.

NRG's generation facilities and the facilities of third parties on which they rely may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of the facilities ability to generate, transmit, transport or distribute electricity or natural gas. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Hostile cyber intrusions, including those targeting information systems as well as electronic control systems used at the generating plants and for the distribution systems, could severely disrupt business operations and result in loss of service to customers, as well as significant expense to repair security breaches or system damage. Any such environmental repercussions or disruption could result in a significant decrease in revenues or significant reconstruction or remediation costs, beyond what could be recovered through insurance policies which could have a material adverse effect on the Company's financial condition, results of operations and cash flow.

NRG's level of indebtedness could adversely affect its ability to raise additional capital to fund its operations, or return capital to stockholders. It could also expose it to the risk of increased interest rates and limit its ability to react to changes in the economy or its industry.

NRG's substantial debt could have negative consequences, including:

- increasing NRG's vulnerability to general economic and industry conditions;
- requiring a substantial portion of NRG's cash flow from operations to be dedicated to the payment of principal and interest on its indebtedness, therefore reducing NRG's ability to pay dividends to holders of its preferred or common stock or to use its cash flow to fund its operations, capital expenditures and future business opportunities;
- limiting NRG's ability to enter into long-term power sales or fuel purchases which require credit support;
- exposing NRG to the risk of increased interest rates because certain of its borrowings, including borrowings under its senior secured credit facility are at variable rates of interest;
- limiting NRG's ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and
- limiting NRG's ability to adjust to changing market conditions and placing it at a competitive disadvantage compared to its competitors who have less debt.

The indentures for NRG's notes and senior secured credit facility contain financial and other restrictive covenants that may limit the Company's ability to return capital to stockholders or otherwise engage in activities that may be in its long-term best interests. Furthermore, financial and other restrictive covenants contained in any project level subsidiary debt may limit the ability of NRG to receive distributions from such subsidiary. NRG's failure to comply with those covenants could result in an event of default which, if not cured or waived, could result in the acceleration of all of the Company's indebtedness.

In addition, NRG's ability to arrange financing, either at the corporate level or at a non-recourse project-level subsidiary, and the costs of such capital, are dependent on numerous factors, including:

- general economic and capital market conditions;
- credit availability from banks and other financial institutions;
- investor confidence in NRG, its partners and the regional wholesale power markets;
- NRG's financial performance and the financial performance of its subsidiaries;
- NRG's level of indebtedness and compliance with covenants in debt agreements;
- maintenance of acceptable credit ratings;
- cash flow; and
- provisions of tax and securities laws that may impact raising capital.

NRG may not be successful in obtaining additional capital for these or other reasons. The failure to obtain additional capital from time to time may have a material adverse effect on its business and operations.

Goodwill and/or other intangible assets not subject to amortization that NRG has recorded in connection with its acquisitions are subject to mandatory annual impairment evaluations and as a result, the Company could be required to write off some or all of this goodwill and other intangible assets, which may adversely affect the Company's financial condition and results of operations.

In accordance with ASC 350, Intangibles — Goodwill and Other, or ASC 350, goodwill is not amortized but is reviewed annually or more frequently for impairment and other intangibles are also reviewed at least annually or more frequently, if certain conditions exist, and may be amortized. Any reduction in or impairment of the value of goodwill or other intangible assets will result in a charge against earnings which could materially adversely affect NRG's reported results of operations and financial position in future periods.

A valuation allowance may be required for NRG's deferred tax assets.

A valuation allowance may need to be recorded against deferred tax assets that the Company estimates are more likely than not to be unrealizable, based on available evidence at the time the estimate is made. A valuation allowance related to deferred tax assets can be affected by changes to tax laws, statutory tax rates and future taxable income levels. In the event that the Company determines that it would not be able to realize all or a portion of its net deferred tax assets in the future, the Company would reduce such amounts through a charge to income tax expense in the period in which that determination was made, which could have a material adverse impact on the Company's financial condition and results of operations.

Volatile power supply costs and demand for power could adversely affect the financial performance of NRG's Retail Business.

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

- varying supply procurement contracts used and the timing of entering into related contracts;
- subsequent changes in the overall price of natural gas;
- daily, monthly or seasonal fluctuations in the price of natural gas relative to the 12-month forward prices;
- transmission constraints and the Company's ability to move power to its customers; and
- changes in market heat rate (i.e., the relationship between power and natural gas prices).

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

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

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

The Company's Retail Business may lose a significant number of retail customers due to competitive marketing activity by other retail electricity providers which could adversely affect the financial performance of NRG's Retail Business.

The Retail Business faces competition for customers. Competitors may offer lower prices and other incentives, which may attract customers away from the Retail Business. In some retail electricity markets, the principal competitor may be the incumbent retail electricity provider. The incumbent retail electricity provider has the advantage of long-standing relationships with its customers, including well-known brand recognition. Furthermore, the Retail Business may face competition from a number of other energy service providers, other energy industry participants, or nationally branded providers of consumer products and services who may develop businesses that will compete with NRG and its Retail Business.

The Company's Retail Business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to its reputation and/or the results of operations of the Retail Business.

The Retail Business requires access to sensitive customer data in the ordinary course of business. Examples of sensitive customer data are names, addresses, account information, historical electricity usage, expected patterns of use, payment history, credit bureau data, credit and debit card account numbers, drivers license numbers, social security numbers and bank account information. The Retail Business may need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center operations, to the Retail Business. If a significant breach occurred, the reputation of NRG and the Retail Business may be adversely affected, customer confidence may be diminished, or NRG and the Retail Business may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations.

CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

This Annual Report on Form 10-K of NRG Energy, Inc., or NRG or the Company, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or Exchange Act. The words "believes," "projects," "anticipates," "plans," "expects," "intends," "estimates" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause NRG's actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Item 1A — Risk Factors Related to NRG Energy, Inc. and the following:

- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- Volatile power supply costs and demand for power;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that NRG may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of NRG's risk management policies and procedures, and the ability of NRG's counterparties to satisfy their financial commitments;
- Counterparties' collateral demands and other factors affecting NRG's liquidity position and financial condition;
- NRG's ability to operate its businesses efficiently, manage capital expenditures and costs tightly, and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;
- NRG's ability to enter into contracts to sell power and procure fuel on acceptable terms and prices;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Government regulation, including compliance with regulatory requirements and changes in market rules, rates, tariffs and environmental laws and increased regulation of carbon dioxide and other greenhouse gas emissions;
- Price mitigation strategies and other market structures employed by ISOs or RTOs that result in a failure to adequately compensate NRG's generation units for all of its costs;
- NRG's ability to borrow additional funds and access capital markets, as well as NRG's substantial indebtedness and the possibility that NRG may incur additional indebtedness going forward;
- NRG's ability to receive Federal loan guarantees or cash grants to support development projects;
- Operating and financial restrictions placed on NRG and its subsidiaries that are contained in the indentures governing NRG's outstanding notes, in NRG's Senior Credit Facility, and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;
- NRG's ability to implement its strategy of developing and building new power generation facilities, including new solar projects;
- NRG's ability to implement its econrg strategy of finding ways to address environmental challenges while taking advantage of business opportunities;
- NRG's ability to implement its FORNRG strategy to increase cash from operations through operational and commercial initiatives, corporate efficiencies, asset strategy, and a range of other programs throughout the company to reduce costs or generate revenues;
- NRG's ability to achieve its strategy of regularly returning capital to stockholders;
- NRG's ability to maintain retail market share;
- NRG's ability to successfully evaluate investments in new business and growth initiatives;
- NRG's ability to successfully integrate, realize cost savings and manage any acquired businesses; and
- NRG's ability to develop and maintain successful partnering relationships.

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

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Listed below are descriptions of NRG's interests in facilities, operations and/or projects owned or leased as of December 31, 2013. The MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the Company's owned or leased interest excluding capacity from inactive/mothballed units as of December 31, 2013. The following table summarizes NRG's power production and cogeneration facilities by region:

Name and Location of Facility	Power Market	% Owned[a][b]		Net Generation Capacity (MW) [c]	Primary Fuel-type
Texas Region:					
Cedar Bayou, Baytown, TX	ERCOT	100.0		1,495	Natural Gas
Cedar Bayou 4, Baytown, TX	ERCOT	50.0		249	Natural Gas
Greens Bayou, Houston, TX	ERCOT	100.0		651	Natural Gas
Gregory, Corpus Christi, TX	ERCOT	100.0		388	Natural Gas
Limestone, Jewett, TX	ERCOT	100.0		1,689	Coal
San Jacinto, LaPorte, TX	ERCOT	100.0		162	Natural Gas
South Texas Project, Bay City, TX [d]	ERCOT	44.0		1,176	Nuclear
S. R. Bertron, Deer Park, TX [e]	ERCOT	100.0		727	Natural Gas
T. H. Wharton, Houston, TX	ERCOT	100.0		1,025	Natural Gas
W. A. Parish, Thompsons, TX	ERCOT	100.0		2,504	Coal
W. A. Parish, Thompsons, TX	ERCOT	100.0		1,220	Natural Gas
	Total net Texas Region			11,286	
East Region:					
Arthur Kill, Staten Island, NY	NYISO	100.0		858	Natural Gas
Astoria Gas Turbines, Queens, NY	NYISO	100.0		508	Natural Gas
Aurora, IL	PJM	100.0		878	Natural Gas
Avon Lake, OH [f]	PJM	100.0		732	Coal
Avon Lake, OH	PJM	100.0		21	Oil
Blossburg, PA	PJM	100.0		19	Natural Gas
Bowline, West Haverstraw, NY	NYISO	100.0		758	Natural Gas
Brunot Island, Pittsburg, PA	PJM	100.0		259	Natural Gas
Canal, Sandwich, MA	ISO-NE	100.0		1,112	Oil
Chalk Point, Aquasco, MD [g]	PJM	100.0		667	Coal
Chalk Point, Aquasco, MD	PJM	100.0		1,690	Natural Gas
Cheswick, Springdale, PA	PJM	100.0		565	Coal
Conemaugh, New Florence, PA	PJM	20.2	[a]	343	Coal
Conemaugh, New Florence, PA	PJM	20.2	[a]	2	Oil
Connecticut Jet Power, CT (four sites)	ISO-NE	100.0		142	Oil
Devon, Milford, CT	ISO-NE	100.0		133	Oil
Dickerson, MD [g]	PJM	100.0	[b]	537	Coal
Dickerson, MD	PJM	100.0	[b]	312	Natural Gas
Dunkirk, NY [f]	NYISO	100.0		75	Coal
Gilbert, Milford, NJ [h]	PJM	100.0		536	Natural Gas
Glen Gardner, NJ [h]	PJM	100.0		160	Natural Gas
Hamilton, East Berlin, PA	PJM	100.0		20	Oil
Hunterstown CCGT, Gettysburg, PA	PJM	100.0		810	Natural Gas
Hunterstown CTS, Gettysburg, PA	PJM	100.0		60	Natural Gas
Huntley, Tonawanda, NY	NYISO	100.0		380	Coal
Indian River, Millsboro, DE	PJM	100.0		400	Coal

Indian River, Millsboro, DE	PJM	100.0	16	Oil

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Kendall, Cambridge, MA	ISO-NE	100.0		256	Natural Gas
Keystone, Shelocta, PA	PJM	20.4	(a)	346	Coal
Keystone, Shelocta, PA	PJM	20.4	(a)	2	Oil
Martha's Vineyard, MA	ISO-NE	100.0		14	Oil
Middletown, CT	ISO-NE	100.0		770	Oil
Montville, Uncasville, CT	ISO-NE	100.0		494	Oil
Morgantown, Newburg, MD	PJM	100.0	(b)	1,229	Coal
Morgantown, Newburg, MD	PJM	100.0	(b)	248	Oil
Mountain, Mount Holly Springs, PA	PJM	100.0		40	Oil
New Castle, West Pittsburgh, PA (f)	PJM	100.0		325	Coal
New Castle, West Pittsburgh, PA	PJM	100.0		3	Oil
Niles, OH	PJM	100.0		25	Oil
Orrtana, PA	PJM	100.0		20	Oil
Oswego, NY	NYISO	100.0		1,628	Oil
Osceola, Holopaw, FL	FRCC	100.0		463	Natural Gas
Portland, Mount Bethel, PA (h)	PJM	100.0		158	Coal
Portland, Mount Bethel, PA	PJM	100.0		169	Oil
Sayreville, NJ	PJM	100.0		224	Natural Gas
Seward, New Florence, PA	PJM	100.0		525	Coal
Shawnee, East Stroudsburg, PA	PJM	100.0		20	Oil
Shawville, PA (i)	PJM	100.0	(b)	597	Coal
Shawville, PA	PJM	100.0	(b)	6	Oil
Titus, Birdsboro, PA	PJM	100.0		31	Oil
Tolna, Stewardstown, PA	PJM	100.0		39	Oil
Vienna, MD	PJM	100.0		167	Oil
Warren, PA	PJM	100.0		57	Natural Gas
Werner, South Amboy, NJ (h)	PJM	100.0		212	Oil
	Total net East Region			20,061	
South Central Region:					
Bayou Cove, Jennings, LA	MISO	100.0		300	Natural Gas
Big Cajun I, Jarreau, LA	MISO	100.0		430	Natural Gas
Big Cajun II, New Roads, LA (f)	MISO	85.8	(j)	1,496	Coal
Choctaw, French Camp, MS	MISO	100.0		800	Natural Gas
Cottonwood, Deweyville, TX	MISO	100.0		1,263	Natural Gas
Rockford, IL	PJM	100.0		450	Natural Gas
Sabine Cogen, Orange, TX	MISO	50.0		54	Natural Gas
Shelby County, Neoga, IL	MISO	100.0		344	Natural Gas
Sterlington, LA	MISO	100.0		176	Natural Gas
	Total net South Central Region			5,313	
West Region:					
Coolwater, Dagget, CA	CAISO	100.0		636	Natural Gas
El Segundo Power, CA	CAISO	100.0		335	Natural Gas
El Segundo Energy Center, CA	CAISO	100.0		550	Natural Gas
Ellwood, Goleta, CA	CAISO	100.0		54	Natural Gas
Encina, Carlsbad, CA	CAISO	100.0		965	Natural Gas
Etiwanda, Rancho Cucamonga, CA	CAISO	100.0		640	Natural Gas
Long Beach, CA	CAISO	100.0		260	Natural Gas
Mandalay, Oxnard, CA	CAISO	100.0		560	Natural Gas
Ormond Beach, Oxnard, CA	CAISO	100.0		1,516	Natural Gas

Pittsburg, CA	CAISO	100.0	1,029	Natural Gas
Saguaro Power Co., Henderson, NV	WECC	50.0	46	Natural Gas
San Diego Combustion Turbines, CA (three sites) [(k)]	CAISO	100.0	188	Natural Gas
	Total net West Region		6,779	

Alternative Energy:				
Agua Caliente, Dateland, AZ	CAISO/WECC	51.0	290	Solar
California Valley Solar Ranch, San Luis Obispo County, CA	CAISO/WECC	51.1	128	Solar
Distributed Solar	AZNMSNV/WECC	100.0	37	Solar
Elbow Creek Wind Farm, Howard County, TX	ERCOT	100.0	122	Wind
High Desert, Lancaster, CA	CAISO	100.0	20	Solar
Ivanpah, Ivanpah Dry Lake, CA	CAISO	50.1	378	Solar
Kansas South, Kings County, CA	CAISO	100.0	20	Solar
Langford Wind Farm, Christoval, TX	ERCOT	100.0	150	Wind
Sherbino Wind Farm, Pecos County, TX	ERCOT	50.0	75	Wind
	Total Alternative Energy		1,220	
Alternative Energy capacity attributable to noncontrolling interest			(331)	
Total net Alternative Energy			889	
NRG Yield:				
Avenal, CA	CAISO	50.0	23	Solar
Avra Valley, Pima County, AZ	CAISO	100.0	25	Solar
Alpine, Lancaster, CA	CAISO	100.0	66	Solar
Blythe, CA	CAISO	100.0	21	Solar
Borrego, Borrego Springs, CA	CAISO	100.0	26	Solar
California Valley Solar Ranch, San Luis Obispo County, CA	CAISO/WECC	49.0	122	Solar
Dover Cogeneration, DE	PJM	100.0	104	Natural Gas
Distributed Solar, AZ	AZNMSNV	100.0	5	Solar
Distributed Solar, CA	WECC	51.0	5	Solar
GenConn Devon, Milford, CT	ISO-NE	50.0	95	Dual-fuel
GenConn Middletown, CT	ISO-NE	50.0	95	Dual-fuel
Marsh Landing, Antioch, CA	CAISO	100.0	720	Natural Gas
Paxton Creek Cogeneration, Harrisburg, PA	PJM	100.0	12	Natural Gas
Princeton Hospital, NJ [(l)]	PJM	100.0	5	Natural Gas
Roadrunner, Santa Teresa, NM	WECC	100.0	20	Solar
South Trent Wind Farm, Sweetwater, TX	ERCOT	100.0	101	Wind
Tucson Convention Center, Tucson, AZ	WECC	100.0	2	Natural Gas
	Total NRG Yield		1,447	
NRG Yield capacity attributable to noncontrolling interest			(499)	
Total net NRG Yield			948	
Other Conventional Generation:				
Gladstone Power Station, Queensland, Australia	Enertrade/Boyne Smelter	37.5	605	Coal
	Total net Other		605	
Total generation capacity			46,711	
Total capacity attributable to noncontrolling interest			(830)	
Total net generation capacity			45,881	

(a) NRG has 16.5% and 16.7% leased interests in the Conemaugh and Keystone facilities, respectively, as well as 3.7% ownership interests in each facility. NRG operates the Conemaugh and Keystone facilities.

(b) NRG leases 100% interests in the Dickerson and Morgantown coal generation units through facility lease agreements expiring in 2029 and 2034, respectively. NRG owns 310 MW and 250 MW of peaking capacity at the Dickerson and Morgantown generating facilities, respectively. NRG also leases a 100% interest in Shawville through a facility lease agreement expiring in 2026. NRG operates the Dickerson, Morgantown and Shawville facilities.

(c) Actual capacity can vary depending on factors including weather conditions, operational conditions, and other factors. Additionally, ERCOT requires periodic demonstration of capability, and the capacity may vary individually and in the aggregate from time to time.

(d) Generation capacity figure consists of the Company's 44% individual interest in the two units at STP.

(e) The four S. R. Bertron steam units and blackstart unit are currently mothballed according to ERCOT protocols, but all operated in 2013.

(f) NRG intends to add natural gas capabilities at the Avon Lake and New Castle facilities, which projects are expected to be completed by the summer of 2016. NRG also intends to add natural gas capabilities at the Big Cajun II and Dunkirk plants which projects are expected to be completed by the spring of 2015 and the fall of 2015, respectively.

(g) On November 29, 2013, NRG submitted a notice of deactivation to retire Chalk Point Units 1 and 2, and Dickerson Units 1, 2, and 3 on May 31, 2017. The deactivation is based on draft environmental regulations that, if adopted, could require uneconomic capital investment and render the units uneconomic to operate going forward.

(h) NRG has submitted deactivation notices for net generation capacity at the following facilities acquired through the GenOn Merger:

Facility	Expected Deactivation Date	Net Generation Capacity (MW)
Gilbert	May 2015	98
Glen Gardner	May 2015	160
Portland	June 2014	158
Werner	May 2015	210

(i) NRG expects to place the coal-fired units at the Shawville generating facility (597 MW) in long-term protective layup in April 2015.

(j) Units 1 and 2 owned 100.0%, Unit 3 owned 58.0%.

(k) NRG operates these units, located on property owned by San Diego Gas & Electric, under a license agreement which is set to end on December 31, 2015.

(l) The output of Princeton Hospital is primarily dedicated to serving the hospital. Excess power is sold to the local utility under its state-jurisdictional tariff.

Thermal Facilities

The Company's thermal businesses in Pittsburgh, Harrisburg and San Francisco are regulated by their respective state's Public Utility Commission. The other thermal businesses are subject to contract terms with their customers. The Company's thermal businesses are owned by NRG Yield LLC.

The following table summarizes NRG's thermal steam and chilled water facilities as of December 31, 2013:

Name and Location of Facility	% Owned	Thermal Energy Purchaser	Megawatt Thermal Equivalent Capacity (MWt)	Generating Capacity
NRG Energy Center Minneapolis, MN	100.0	Approx. 100 steam and 50 chilled water customers	334 141	Steam: 1,140 MMBtu/hr. Chilled water: 40,200 tons
NRG Energy Center San Francisco, CA	100.0	Approx 175 steam customers	133	Steam: 454 MMBtu/hr.
NRG Energy Center Omaha, NE	100.0 12.0 100.0	Approx 60 steam and 60 chilled water customers	142 9 77	Steam: 485 MMBtu/hr Steam: 30 MMBtu/hr Chilled water: 22,000 tons
NRG Energy Center Harrisburg, PA	100.0	Approx 140 steam and 3 chilled water customers	129 12	Steam: 440 MMBtu/hr. Chilled water: 3,600 tons
NRG Energy Center Phoenix, AZ	100.0 0%[a]	Approx 35 chilled water customers	106 28	Chilled water: 30,100 tons

				Chilled water: 8,000 tons
NRG Energy Center Pittsburgh, PA	100.0	Approx 25 steam and 25 chilled water customers	87 46	Steam: 296 MMBtu/hr. Chilled water: 12,920 tons
NRG Energy Center San Diego, CA	100.0	Approx 20 chilled water customers	26	Chilled water: 7,425 tons
NRG Energy Center Dover, DE	100.0	Kraft Foods Inc. and Procter & Gamble Company	66	Steam: 225 MMBtu/hr.
NRG Energy Center Princeton, NJ	100.0	Princeton HealthCare System	21 17	Steam: 72 MMBtu/hr. Chilled water: 4,700 tons
		Total Generating Capacity (MWt)	1,374	

(a) Capacity available under right-to-use provision of the Chilled Water Service Agreement.

Other Properties

NRG owns, net of noncontrolling interest, 50 MW of Distributed Solar facilities, 44 MW of which is operational, at various locations throughout the United States, concentrated primarily in the West Region.

In addition, NRG owns several real properties and facilities relating to its generation assets, other vacant real property unrelated to the Company's generation assets, interests in construction projects, and properties not used for operational purposes. NRG believes it has satisfactory title to its plants and facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in the Company's opinion, would not have a material adverse effect on the use or value of its portfolio.

NRG leases its financial and commercial corporate headquarters offices at 211 Carnegie Center, Princeton, New Jersey, its operational headquarters in Houston, TX, its Retail Business offices and call centers, and various other office space.

Item 3 — Legal Proceedings

See Item 15 — Note 22, Commitments and Contingencies, to the Consolidated Financial Statements for discussion of the material legal proceedings to which NRG is a party.

Item 4 — Mine Safety Disclosures

Not applicable

PART II

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

Market Information and Holders

NRG's authorized capital stock consists of 500,000,000 shares of NRG common stock and 10,000,000 shares of preferred stock. A total of 22,000,000 shares of the Company's common stock are available for issuance under the NRG LTIP. A total of 5,558,390 shares of NRG common stock were authorized for issuance under the NRG GenOn LTIP. For more information about the NRG LTIP and the NRG GenOn LTIP, refer to Item 15 —Note 20, Stock-Based Compensation. NRG has also filed with the Secretary of State of Delaware a Certificate of Designation for the 3.625% Convertible Perpetual Preferred Stock.

NRG's common stock is listed on the New York Stock Exchange and has been assigned the symbol: NRG. The high and low sales prices, as well as the closing price for the Company's common stock on a per share basis for 2013 and 2012 are set forth below:

Common Stock Price	Fourth Quarter 2013	Third Quarter 2013	Second Quarter 2013	First Quarter 2013	Fourth Quarter 2012	Third Quarter 2012	Second Quarter 2012	First Quarter 2012
High	$30.28	$29.19	$28.67	$26.51	$23.78	$22.92	$17.49	$18.46
Low	26.30	25.24	24.86	22.60	19.15	16.66	14.29	15.53
Closing	28.72	27.33	26.70	26.49	22.99	21.39	17.36	15.67
Dividends Per Common Share	$0.12	$0.12	$0.12	$0.09	$0.09	$0.09	$—	$—

NRG had 323,779,252 shares outstanding as of December 31, 2013. As of February 26, 2014, there were 325,217,179 shares outstanding, and there were 30,064 common stockholders of record.

Dividends

On February 17, 2014, NRG paid a quarterly dividend on the Company's common stock of $0.12 per share.

Repurchase of equity securities

For the year ended December 31, 2013	Total number of shares purchased	Average price paid per share(a)	Total number of shares purchased under the 2013 Capital Allocation Program	Dollar value of shares that may be purchased under the 2013 Capital Allocation Program(b)
First quarter 2013	972,292	$25.88	972,292	$174,828,171
Year-to-date 2013	972,292	$25.88	972,292	$174,828,171

(a) The average price paid per share excludes commissions of $0.015 per share paid in connection with the share repurchases.

(b) Includes commissions of $0.015 per share paid in connection with the share repurchases.

On February 27, 2013, the Company announced a plan to repurchase $200 million of its common stock in 2013 under the 2013 Capital Allocation Program. During the first quarter, the Company purchased 972,292 shares of NRG common stock for $25 million at an average cost of $25.88 per share. As a result of the proposed acquisition of EME, the Company did not complete the remaining $175 million of share repurchases under the 2013 Capital Allocation Program.

Stock Performance Graph

The performance graph below compares NRG's cumulative total stockholder return on the Company's common stock for the period December 31, 2008, through December 31, 2013, with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, or S&P 500, and the Philadelphia Utility Sector Index, or UTY. NRG's common stock trades on the New York Stock Exchange under the symbol "NRG."

The performance graph shown below is being furnished and compares each period assuming that $100 was invested on December 31, 2008 in each of the common stock of NRG, the stocks included in the S&P 500 and the stocks included in the UTY, and that all dividends were reinvested.

Comparison of Cumulative Total Return

	Dec-2008	Dec-2009	Dec-2010	Dec-2011	Dec-2012	Dec-2013
NRG Energy, Inc.	$100.00	$101.21	$83.76	$77.67	$99.41	$126.26
S&P 500	100.00	126.48	145.52	148.59	172.37	228.19
UTY	100.00	110.05	116.31	138.73	137.95	153.12

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Item 6 — Selected Financial Data

The following table presents NRG's historical selected financial data. The data included in the following table has been recast to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations in 2009. This historical data should be read in conjunction with the Consolidated Financial Statements and the related notes thereto in Item 15 and Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. The Company has completed several acquisitions and dispositions, as described in Item 15 - Note 3, Business Acquisitions and Dispositions.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions except ratios and per share data)				
Statement of income data:					
Total operating revenues	$11,295	$8,422	$9,079	$8,849	$8,952
Total operating costs and expenses, and other expenses [(b)]	11,929	8,434	9,725	8,119	7,283
(Loss)/Income from continuing operations, net	(352)	315	197	476	941
Net (loss)/income attributable to NRG Energy, Inc.	$(386)	$295	$197	$477	$942
Common share data:					
Basic shares outstanding — average	323	232	240	252	246
Diluted shares outstanding — average	323	234	241	254	271
Shares outstanding — end of year	324	323	228	247	254
Per share data:					
Net (loss)/income attributable to NRG — basic	(1.22)	1.23	0.78	1.86	3.70
Net (loss)/income attributable to NRG — diluted	(1.22)	1.22	0.78	1.84	3.44
Dividends declared per common share	$0.45	$0.18	$—	$—	$—
Book value	$32.33	$31.83	$33.71	$32.65	$29.72
Business metrics:					
Cash flow from operations	$1,270	$1,149	$1,166	$1,623	$2,106
Liquidity position [(a)]	$3,695	$3,362	$2,328	$4,660	$3,971
Ratio of earnings to fixed charges	0.30	0.86	0.77	2.03	3.27
Ratio of earnings to fixed charges and preferred dividends	0.29	0.85	0.76	1.99	3.04
Return on equity	(3.69)%	2.87%	2.57%	5.91%	12.24%
Ratio of debt to total capitalization	57.60%	56.74%	52.43%	42.94%	43.49%
Balance sheet data:					
Current assets	$7,596	$7,972	$7,749	$7,137	$6,208
Current liabilities	4,204	4,670	5,861	4,220	3,762
Property, plant and equipment, net	19,851	20,153	13,621	12,517	11,564
Total assets	33,902	34,983	26,900	26,896	23,378
Long-term debt, including current maturities, capital leases, and funded letter of credit	16,817	15,883	9,832	10,511	8,418
Total stockholders' equity	$10,469	$10,269	$7,669	$8,072	$7,697

(a) Liquidity position is determined as disclosed in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, Liquidity Position. It includes funds deposited by counterparties of $63 million, $271 million, and $258 million as of December 31, 2013, 2012, and 2011, respectively, which represents cash held as collateral from hedge counterparties in support of energy risk management activities. It is the Company's intention to limit the use of these funds for repayment of the related current liability for collateral received in support of energy risk management activities.

(b)

The Company recorded impairment losses in 2013 and 2011 as further described in Item 15 - Note 10, Asset Impairments.

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

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions)				
Energy revenue	$5,606	$3,776	$3,804	$4,063	$4,087
Capacity revenue	1,860	800	750	840	1,070
Retail revenue	6,297	5,888	5,807	5,277	4,440
Mark-to-market for economic hedging activities	(542)	(450)	325	(199)	(107)
Contract amortization	(32)	(97)	(159)	(195)	(179)
Other revenues	433	302	342	361	62
Eliminations	(2,327)	(1,797)	(1,790)	(1,298)	(421)
Total operating revenues	$11,295	$8,422	$9,079	$8,849	$8,952

Energy revenue consists of revenues received from third parties for sales of electricity in the day-ahead and real-time markets, as well as bilateral sales. It also includes energy sold through long-term PPAs for renewable facilities. In addition, energy revenue includes revenues from the settlement of financial instruments and net realized trading revenues.

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

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

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges.

Contract amortization revenue consists of the amortization of the intangible assets for net in-market C&I contracts established in connection with the acquisitions of Reliant Energy and Green Mountain Energy, as well as acquired power contracts, gas derivative instruments, and certain power sales agreements assumed at Fresh Start and Texas Genco purchase accounting dates related to the sale of electric capacity and energy in future periods. These amounts are amortized into revenue over the term of the underlying contracts based on actual generation or contracted volumes.

Other revenues include revenues generated by the Thermal business consisting of revenues received from the sale of steam, hot and chilled water generally produced at a central district energy plant and sold to commercial, governmental and residential buildings for space heating, domestic hot water heating and air conditioning. It also includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process. Other revenues also consists of operations and maintenance fees, or O&M fees, construction management services, or CMA fees, sale of natural gas and emission allowances, and revenues from ancillary services. O&M fees consist of revenues received from providing certain unconsolidated affiliates with services under long-term operating agreements. CMA fees are earned where NRG provides certain management and oversight of construction projects pursuant to negotiated agreements such as for the GenConn, Cedar Bayou 4 and certain solar construction projects. Ancillary services are comprised of the sale of energy-related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products. Other revenues also includes unrealized trading activities.

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

The discussion and analysis below has been organized as follows:

- Executive Summary, including business strategy, the business environment in which NRG operates, how regulation, weather, competition and other factors affect the business, and significant events that are important to understanding the results of operations and financial condition for the 2013 period;
- Results of operations, including an explanation of significant differences between the periods in the specific line items of NRG's Consolidated Statements of Operations;
- Financial condition addressing credit ratings, liquidity position, sources and uses of cash, capital resources and requirements, commitments, and off-balance sheet arrangements; and
- Critical accounting policies which are most important to both the portrayal of the Company's financial condition and results of operations, and which require management's most difficult, subjective or complex judgment.

As you read this discussion and analysis, refer to NRG's Consolidated Statements of Operations to this Form 10-K, which presents the results of the Company's operations for the years ended December 31, 2013, 2012, and 2011, and also refer to Item 1 to this Form 10-K for more detailed discussion about the Company's business.

Executive Summary

NRG's Business Strategy

The Company's business is focused on: (i) excellence in operating performance of its existing assets; (ii) serving the energy needs of end-use residential, commercial and industrial customers in competitive markets through multiple brands and channels with a variety of retail energy products and services differentiated by innovative features, premium service, sustainability, and loyalty/affinity programs; (iii) optimal hedging of generation assets and retail load operations; (iv) repowering of power generation assets at premium sites; (v) investing in, and deploying, alternative energy technologies both in its wholesale and, particularly, in and around its Retail Business and its customers; (vi) pursuing selective acquisitions, joint ventures, divestitures and investments; and (vii) engaging in a proactive capital allocation plan focused on achieving the regular return of and on stockholder capital within the dictates of prudent balance sheet management. Underlying each aspect of the Company’s business is the Company’s commitment to safety for its employees, customers and partners.

In addition, the Company's subsidiary, NRG Yield, Inc., is focused on enhancing value for its stockholders by: (i) providing investors with a more competitive source of equity capital that would accelerate NRG's long-term growth and acquisition strategy and optimize NRG's capital structure; and (ii) highlighting the reduced market exposure associated with the contracted conventional and renewable generation and thermal infrastructure assets embedded with NRG's merchant portfolio.

The Company believes that the U.S. energy industry is going to be increasingly impacted by the long-term societal trend towards sustainability, which is both generational and irreversible. Moreover, it further believes the information technology-driven revolution, which has enabled greater and easier personal choice in other sectors of the consumer economy, will do the same in the U.S. energy sector over the years to come. Finally, NRG believes that the aging transmission and distribution infrastructure of the national grid is becoming increasingly inadequate in the face of the more extreme weather demands of the 21st century. As a result, energy consumers are expected to have increasing personal control over whom they buy their energy from, how that energy is generated and used (including their ability to self-generate from their own primarily sustainable energy resources) and what environmental impact individual choices will have. The Company's initiatives in this area of future growth are focused on: (i) renewables, with a concentration in solar and wind development; (ii) electric vehicle ecosystems; (iii) customer-facing energy products and services, including smart energy services that give consumers individual energy insights, choices and convenience, a variety of renewable and energy efficiency products, and numerous loyalty and affinity options and tailored product and service bundles sold through unique retail sales channels; and (iv) construction of other forms of on-site clean power generation. The Company's advances in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in Item 1, Business - New and On-going Company Initiatives and Development Projects and in Management's Discussion and Analysis of Financial Condition and Results of Operations, New and On-going Company Initiatives and Development Projects, in this Form 10-K.

In summary, NRG's business strategy is intended to maximize stockholder value through the production and sale of safe, reliable and affordable power to its customers in the markets served by the Company, while aggressively positioning the Company to meet the market's increasing demand for sustainable and low carbon energy solutions individualized for the benefit of the end use energy consumer. This strategy is designed to enhance the Company's core business of competitive power generation and mitigate the risk of declining power prices. The Company is a leading provider of sustainable energy solutions that promote both consumer welfare and national energy security.

Business Environment

The industry dynamics and external influences affecting the Company and the power generation industry in 2013 and for the future medium term include:

Natural Gas Market — The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants. Natural gas prices are driven by variables including demand from the industrial, residential, and electric sectors, productivity across natural gas supply basins, costs of natural gas production, changes in pipeline infrastructure, and the financial and hedging profile of natural gas consumers and producers. In 2013, average natural gas prices at Henry Hub were 31% higher than 2012. Although supply continues to increase, reflecting increased production from mainly the shale basins, winter weather in January 2014 caused natural gas within several Northeastern points to trade in excess of $100/MMbtu. Coordination between gas pipelines, local distribution company home heating load, gas generators, and ISOs needs to improve to ensure there are no reliability issues in the winter when home heating demands and the increased reliance on gas generation come into conflict.

If long-term gas prices decrease or remain depressed, the Company is likely to encounter lower realized energy prices, leading to lower energy revenues as higher priced hedge contracts mature and are replaced by contracts with lower gas and power prices. The Retail Business's gross margins have historically improved as natural gas prices decline and are likely to partially offset the impact of declining gas prices on conventional wholesale power generation. To further mitigate this impact, NRG may increase its percentage of coal and nuclear capacity sold forward using a variety of hedging instruments, as described under the heading Energy Related Commodities in Item 15 — Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements. The Company also mitigates declines in long term gas prices through its increased investment in renewable power generation supported by PPAs as well as through the increasing portion of the fleet which benefits from capacity payments.

Electricity Prices — The price of electricity is a key determinant of the profitability of the Company's generation portfolio. Many variables such as the price of different fuels, weather, load growth and unit availability all coalesce to impact the final price for electricity and the Company's profitability. In 2013, electricity prices in the Company's core markets were generally higher than 2012 primarily due to higher natural gas prices. Prices were lower in 2012 compared to 2011 mainly due to lower gas prices, lack of weather and negligible demand growth. The following table summarizes average on-peak power prices for each of the major markets in which NRG operates for the years ended December 31, 2013, 2012, and 2011:

	Average on Peak Power Price ($/MWh)		
Region	2013	2012	2011
Texas[(a)]	$34.12	$29.10	$57.42
East	52.99	41.50	53.09
NY J/NYC	62.31	46.90	62.34
NY A/West NY	44.71	36.27	42.14
NEPOOL	65.32	41.61	52.80
PEPCO (PJM)	48.65	42.62	56.40
PJM West Hub	45.21	39.87	51.33
South Central[(b)]	33.32	28.72	37.38
West[(c)]	46.13	33.44	36.39

(a) Average on-peak market power prices calculated based on average settled market prices in ERCOT - Houston and ERCOT - North.

(b) Average on-peak market power prices for South Central region are calculated based on average day ahead market prices for "into Entergy" as published in the Platts Megawatt Daily report.

(c) Average on-peak market power prices calculated based on average settled market prices in CAISO - NP15 and CAISO - SP15.

Capacity Markets — Capacity markets are a major source of revenue for the Company. There are both bilateral markets and ISO auctions, depending on the region. In the Northeast, ISOs use a forward auction to procure the capacity necessary to meet reliability standards, to forge unit commitments, and to set the price of capacity. These auctions are either an annual market held three years ahead of the delivery period as in the case of PJM and ISO-NE, or six months to one month ahead as in the case of New York. Many variables play into the prices derived in these auctions. These variables include the load forecast, the target reserve margin, rules surrounding demand response, capacity imports and exports from the region, new generation entrants, slope of the demand curve, generation retirements, the cost of retrofitting old generation to meet new environmental rules, expected profitability of the plant itself in the energy market, rules about the transfer of capacity within the ISO but between different regions and various other auction rules. In theory, a high capacity price should be an indication that the ISO doesn't have sufficient generation capacity against its needed reserve margin and new constuction should enter the market. Similarly, a low capacity price suggests the market is over-built and units should retire. The Company has seen many swings in the pricing for capacity markets. The PJM auction held last May for delivery in 2016/2017 cleared lower than expected. The ISO-NE auction for the same time-frame cleared at the market floor. However, the very next ISO-NE auction (for 2017/2018) cleared at the administrative ceiling after several plants retired. Many changes are being considered for the upcoming PJM auction for 2017/2018, these include limits on imports and changes to the demand response rules, both of which may have a positive effect on clearing prices.

Consolidation — There were several mergers and acquisitions in the U.S. power sector over the last three years. Over the long term, industry consolidation is expected to continue.

Environmental Regulatory Landscape — The MATS rule, finalized in 2012, is the driving regulatory force behind the decision to retrofit, repower or retire uncontrolled coal fired power plants. Across the nation, companies are moving from the planning stages to implementation in order to meet the 2015 compliance date. A number of regulations on GHGs, ambient air quality, coal combustion byproducts and water use with the potential for increased capital costs or operational impacts have been finalized or are still in development and under review by the EPA. The design, timing and stringency of these regulations will affect the framework for the retrofit or retirement of existing fossil plants and deployment of new, cleaner technologies in the next decade. See Item 1, Business — Environmental Matters, for further discussion.

Public Policy Support and Government Financial Incentives for Clean Infrastructure Development — Policy mechanisms including production and investment tax credits, cash grants, loan guarantees, accelerated depreciation tax benefits, RPS, and carbon trading plans have been implemented at the state and federal levels to support the development of renewable generation, demand-side and smart grid, and other clean infrastructure technologies. The availability and continuation of public policy support mechanisms will drive a significant part of the economics of the Company's development program and expansion into clean energy investments.

Weather

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

Other Factors

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

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

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

- weather conditions;
- market liquidity;
- capability and reliability of the physical electricity and gas systems;
- local transportation systems; and
- the nature and extent of electricity deregulation.

Environmental Matters, Regulatory Matters and Legal Proceedings

Details of other environmental matters are presented in Item 15 — Note 24, Environmental Matters, to the Consolidated Financial Statements and Item 1, Business — Environmental Matters, section. Details of regulatory matters are presented in Item 15 — Note 23, Regulatory Matters, to the Consolidated Financial Statements and Item 1, Business — Regulatory Matters, section. Details of legal proceedings are presented in Item 15 — Note 22, Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information relates to costs that may be material to the Company's financial results.

Impact of inflation on NRG's results

For the years ended December 31, 2013, 2012 and 2011, the impact of inflation and changing prices (due to changes in exchange rates) on NRG's revenues and net income was immaterial.

Significant events during the year ended December 31, 2013

Results of Operations and Financial Condition

- Lower net income — Net income decreased $667 million, as discussed in further detail below.
- GenOn acquisition — On December 14, 2012, NRG completed the acquisition of GenOn and recorded a bargain purchase gain on the acquisition. In December 2013, the Company finalized acquisition accounting for the acquisition, as discussed in more detail in Item 15 - Note 3 - Business Acquisitions and Dispositions.
- Long-term debt — During 2013, the Company increased its non-recourse debt by approximately $669 million primarily in connection with the financing of the construction and acquisition of various solar facilities and the construction of the ESEC and Marsh Landing natural gas facilities.
- Impairment Losses — During the fourth quarter of 2013, the Company recognized impairment losses on its Indian River facility and Gladstone investment, as discussed in more detail in Item 15 - Note 10, Asset Impairments.
- NRG Yield, Inc. initial public offering — During the third quarter of 2013, NRG Yield, Inc. completed its initial public offering of its Class A common shares at a price of $22 per share, which represents 34.5% of NRG Yield.

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Consolidated Results of Operations

2013 compared to 2012

The following table provides selected financial information for the Company:

	Year Ended December 31,		
(In millions except otherwise noted)	2013	2012 [a]	Change %
Operating Revenues			
Energy revenue [b]	$3,530	$2,114	67 %
Capacity revenue [b]	1,800	762	136
Retail revenue	6,292	5,888	7
Mark-to-market for economic hedging activities	(578)	(450)	(28)
Contract amortization	(31)	(97)	68
Other revenues [c]	282	205	38
Total operating revenues	11,295	8,422	34
Operating Costs and Expenses			
Generation cost of sales [b]	3,411	2,123	61
Retail cost of sales [b]	2,861	2,828	1
Mark-to-market for economic hedging activities	(293)	(182)	(61)
Contract and emissions credit amortization [d]	32	39	(18)
Other cost of operations	2,110	1,332	58
Total cost of operations	8,121	6,140	32
Depreciation and amortization	1,256	950	32
Impairment losses	459	—	(100)
Selling, general and administrative	904	807	12
Acquisition-related transaction and integration costs	128	107	100
Development costs	84	68	24
Total operating costs and expenses	10,952	8,072	36
Operating Income	343	350	(2)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	7	37	(81)
Bargain purchase gain related to GenOn acquisition	—	296	100
Impairment losses on investments	(99)	(2)	N/A
Other income, net	13	19	(32)
Loss on debt extinguishment	(50)	(51)	(2)
Interest expense	(848)	(661)	28
Total other expense	(977)	(362)	170
Loss before income tax expense	(634)	(12)	5,183
Income tax benefit	(282)	(327)	(14)
Net (Loss)/Income	(352)	315	(212)
Less: Net income attributable to noncontrolling interest	34	20	100
Net (loss)/income attributable to NRG Energy, Inc.	$(386)	$295	(231)
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	3.65	2.79	31 %

(a) Includes the results of GenOn from December 15, 2012 to December 31, 2012.

(b) Includes realized gains and losses from financially settled transactions.

(c) Includes unrealized trading gains and losses.

(d) Includes amortization of SO_2 and NO_x credits and excludes amortization of RGGI credits.

N/A - Not Applicable

Management's discussion of the results of operations for the years ended December 31, 2013, and 2012

Loss before income tax expense — The pre-tax loss of $634 million for the year ended December 31, 2013, compared to a pre-tax loss of $12 million for the year ended December 31, 2012, primarily reflects:

- in the current year, impairment losses associated with the Indian River facility and the investment in Gladstone;
- increased operating costs of $1,218 million including operations and maintenance expense, depreciation and amortization, selling, general and administrative costs and development costs as well as acquisition-related transaction and integration costs, primarily associated with the acquisition of GenOn; and
- a decrease from net mark-to-market results for economic hedging activities of $17 million;

offset by:

- an increase in gross margin of $1,599 million comprised of an increase in Conventional Generation gross margin of $1,402 million, primarily associated with the acquisition of GenOn, an increase in NRG Yield gross margin of $135 million and an increase in Alternative Energy gross margin of $101 million, offset by a decrease in Retail gross margin of $39 million; and
- the bargain purchase gain related to the GenOn acquisition.

Net (loss)/income — The net loss of $352 million compared to net income in the prior year of $315 million primarily reflects the drivers discussed above.

Conventional Generation gross margin

The following is a discussion of gross margin for NRG's Conventional Generation businesses, adjusted to eliminate intersegment activity, primarily with NRG's Retail Business segment.

	For the Year Ended December 31, 2013									
	Conventional Generation									
(In millions except otherwise noted)	Texas	East	South Central	West	Other	Subtotal	Alternative Energy	NRG Yield (a)	Eliminations/Corporate	Total
Energy revenue	$2,190	$2,400	$566	$155	$—	$5,311	$ 209	$86	$ (2,076)	$3,530
Capacity revenue	103	1,099	245	314	5	1,766	3	91	(60)	1,800
Other revenue	28	76	(1)	4	148	255	22	137	(132)	282
Generation revenue	2,321	3,575	810	473	153	7,332	234	314	(2,268)	5,612
Generation cost of sales	(1,156)	(1,492)	(623)	(119)	(63)	(3,453)	(8)	(62)	$ 112	$(3,411)
Generation gross margin	$1,165	$2,083	$187	$354	$90	$3,879	$ 226	$252		
Business Metrics										
MWh sold (in thousands)(b)	46,250	35,104	17,178	1,695			2,667	963		
MWh generated (in thousands)	40,734	34,211	16,329	3,528			2,159	1,109		

	For the Year Ended December 31, 2012									
	Conventional Generation									
(In millions except otherwise noted)	Texas	East	South Central	West	Other	Subtotal	Alternative Energy	NRG Yield (a)	Eliminations/Corporate	Total
Energy revenue	$2,406	$533	$527	$121	$39	$3,626	$ 117	$33	$ (1,662)	$2,114
Capacity revenue	81	314	240	124	41	800	—	—	(38)	762
Other revenue	28	19	(10)	4	93	134	8	142	(79)	205
Generation revenue	2,515	866	757	249	173	4,560	125	175	(1,779)	3,081
Generation cost of sales	(958)	(440)	(519)	(88)	(78)	(2,083)	—	(58)	18	(2,123)
Generation gross margin	$1,557	$426	$238	$161	$95	$2,477	$ 125	$117		
Business Metrics										
MWh sold (in thousands)(b)	43,707	8,172	17,935	2,146			1,524	464		
MWh generated (in thousands)	37,695	6,469	15,927	2,146			1,524	464		

	Years ended December 31,			
Weather Metrics	Texas	East	South Central	West
2013				
CDDs (c)	2,872	713	1,587	879
HDDs (c)	2,055	6,124	3,642	2,924
2012				
CDDs	3,134	754	1,782	904
HDDs	1,452	5,317	2,861	2,988

30 year average				
CDDs	2,940	660	1,758	831
HDDs	1,800	5,937	3,377	3,049

(a) Yield MWh generated excludes thermal facilities.

(b) MWh sold excludes generation at facilities that generate revenue under capacity agreements.

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

Conventional Generation gross margin — increased by $1,402 million, including intercompany sales, during the years ended December 31, 2013, compared to the same period in 2012, due to:

Decrease in Texas region	$(392)
Increase in East region	1,657
Decrease in South Central region	(51)
Increase in West region	193
Other [(a)]	(5)
	$1,402

(a) Other gross margin primarily represents revenues from the maintenance services business, which are eliminated in consolidation.

The decrease in gross margin in the Texas region was driven by:

Lower gross margin from a decrease in average realized prices	$(431)
Lower gross margin from a 4% decrease in nuclear generation due to more planned outage hours in 2013	(28)
Lower gross margin from a 22% decrease in gas generation due to milder weather in the summer months of 2013	(27)
Higher gross margin driven by a 13% increase in coal generation driven by 4% less outage hours in 2013	85
Higher gross margin due to the acquisition of the Gregory cogeneration plant in August 2013	17
Change in unrealized commercial optimization activities and other	(8)
	$(392)

The increase in gross margin in the East region was driven by:

Higher gross margin from the acquisition of GenOn in December 2012	$1,572
Higher revenue due to a 32% increase in New York and PJM hedged capacity prices and the Dunkirk RSS contract	83
Higher gross margin from coal plants due to an increase in generation and realized prices	39
Lower margins realized on certain load-serving contracts due to increased pricing for power purchases	(33)
Lower gross margin from oil and gas plants due primarily to a 20% decrease in generation offset by a 46% increase in realized energy prices.	(3)
Change in unrealized commercial optimization activities and other	(1)
	$1,657

The decrease in gross margin in the South Central region was driven by:

Lower gross margin from higher gas prices	$(66)
Lower gross margin from higher coal transportation costs	(16)
Higher revenue from an increase in average realized energy prices	28
Change in unrealized commercial optimization activities and other	3
	$(51)

The increase in gross margin in the West region was driven by:

Higher gross margin from the acquisition of GenOn in December 2012	$169
Higher gross margin due to an increase in capacity prices related primarily to El Segundo Energy Center reaching COD in 2013	17
Higher gross margin due to a 43% increase in realized prices offset by a 50% decrease in generation due to new plants coming on line and fewer competitor outages in the region	11
Lower gross margin due to new California emissions program	(11)
Change in unrealized commercial optimization activities and other	7
	$193

Alternative Energy gross margin

NRG's Alternative Energy business segment, which is comprised mainly of the solar and wind businesses that are not part of NRG Yield, had gross margin of $226 million for the year ended December 31, 2013, compared to gross margin of $125 million for the same period in 2012. The increase in gross margin was primarily the result of new project phases reaching COD during the period including 37 MW for Agua Caliente, 66 MW for Alpine and 126 MW for CVSR.

NRG Yield gross margin

NRG Yield had gross margin of $252 million for the year ended December 31, 2013 compared to gross margin of $117 million for the same period in 2012, primarily as a result of new projects reaching COD during late 2012 and in the first half of 2013 including Avra Valley, Alpine, Borrego and Marsh Landing.

Retail gross margin

The following is a discussion of retail gross margin for NRG's Retail Business.

Selected Income Statement Data

	Years ended December 31,	
(In millions except otherwise noted)	2013	2012
Operating Revenues		
Mass revenues	$4,115	$3,813
Commercial and Industrial revenues	1,946	1,929
Supply management revenues	236	151
Retail operating revenues [(a)(b)]	6,297	5,893
Retail cost of sales [(c)]	4,958	4,515
Retail gross margin	$1,339	$1,378
Business Metrics		
Electricity sales volume — GWh		
Mass [(e)]	32,773	31,373
Commercial and Industrial [(d)]	27,118	27,812
Electricity sales volume — GWh		
Texas	50,937	53,451
All other regions	8,955	5,734
Average retail customers count (in thousands, metered locations)		
Mass [(e)]	2,147	2,054
Commercial and Industrial [(d)]	102	91
Retail customers count (in thousands, metered locations)		
Mass [(e)]	2,169	2,108
Commercial and Industrial [(d)]	106	102

(a) Includes customers of the Texas General Land Office for which the Company provides services, as well as sales to utility partner customers.

(b) Includes intercompany sales of $5 million in both 2013 and 2012, representing sales from Retail to the Texas region.

(c) Includes intercompany purchases of $2,097 million and $1,687 million, respectively.

(d) Includes customers of the Texas General Land Office for which the Company provides services.

(e) Excludes utility partner and natural gas customers.

- Retail gross margin — Retail gross margin decreased $39 million for the year ended December 31, 2013, compared to the same period in 2012, driven by

Decrease in unit margins due to higher supply costs and customer mix offset by higher pricing and higher revenues from home and business services	$(59)

Milder weather in 2013 as compared to 2012	(29)
Increase in customer count and usage	49
	$(39)

- Trends — Customer counts increased by approximately 65,000 since December 31, 2012. Competition and higher supply costs based on forward natural gas prices and higher heat rates could drive lower unit margins in the future.

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Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges. Total net mark-to-market results decreased by $17 million during the year ended December 31, 2013, compared to the same period in 2012.

The breakdown of gains and losses included in operating revenues and operating costs and expenses by region was as follows:

	For the Year Ended December 31, 2013							
	Retail	Texas	East	South Central	West	Alternative Energy	Elimination[(a)]	Total
	(In millions)							
Mark-to-market results in operating revenues								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(6)	$(326)	$(4)	$35	$(3)	$—	$(11)	$(315)
Reversal of gain positions acquired as part of the GenOn acquisition	—	—	(401)	—	(2)	—	—	(403)
Net unrealized gains/(losses) on open positions related to economic hedges	1	109	39	10	7	(1)	(25)	140
Total mark-to-market (losses)/gains in operating revenues	$(5)	$(217)	$(366)	$45	$2	$(1)	$(36)	$(578)
Mark-to-market results in operating costs and expenses								
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	$144	$21	$13	$21	$—	$—	$11	$210
Reversal of loss positions acquired as part of the Reliant Energy, Green Mountain Energy and GenOn acquisitions	6	—	40	—	—	—	—	46
Net unrealized gains/(losses) on open positions related to economic hedges	6	19	(11)	1	—	—	22	37
Total mark-to-market gains in operating costs and expenses	$156	$40	$42	$22	$—	$—	$33	$293

(a) Represents the elimination of the intercompany activity between the Retail Business and the Conventional Generation regions.

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the year ended December 31, 2013, the $140 million gain in operating revenues from open positions was due primarily to decreases in forward natural gas and power prices. The $37 million gain in operating costs and expenses from open positions was due primarily to increases in coal prices.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the year ended December 31, 2013, and 2012. The realized and unrealized financial and physical trading results are included in operating revenue. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Year ended December 31,	
(In millions)	2013	2012
Trading gains/(losses)		
Realized	$66	$83

Unrealized	(43)	(14)
Total trading gains	$23	$69

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under acquisition accounting and the favorable change of $66 million, as compared to 2012, related primarily to lower contract amortization of $54 million and $11 million for Reliant Energy and Green Mountain Energy, respectively.

Other Operating Costs

	Retail	Texas	East	South Central	West	Other[(a)]	Alternative Energy	NRG Yield	Eliminations/Corporate	Total
	(In millions)									
Year Ended December 31, 2013	$265	$534	$917	$121	$174	$61	$39	$63	$ (64)	$2,110
Year Ended December 31, 2012	$241	$559	$274	$118	$67	$68	$18	$53	$ (66)	$1,332

(a) The majority of Other is intercompany in nature and eliminates in consolidation.

Other operating costs increased by $778 million for the year ended December 31, 2013, compared to the same period in 2012, due to:

Increase in operations and maintenance expense for GenOn plants acquired in December 2012	$773
Decrease as 2012 reflected return to service costs for S.R. Bertron	(14)
Gain on sale of land recorded in other operating costs in 2013	(10)
Increase in Alternative Energy operations and maintenance expenses as phases of Agua Caliente and CVSR reached commercial operations in 2013	17
Increase in NRG Yield operations and maintenance as Marsh Landing, Avra Valley and Borrego reached commercial operations in 2013	7
Other	5
	$778

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $306 million for the year ended December 31, 2013, compared to the same period in 2012, due primarily to $237 million from the acquisition of GenOn in December 2012 and additional depreciation from solar facilities that reached commercial operations in 2013.

Impairment Losses

In the fourth quarter 2013, the Company recorded an impairment loss of $459 million related to the Indian River facility. The impairment loss resulted from a change in management's long-term view on the economics of the facility, as further described in Item 15 — Note 10, Asset Impairments.

Selling, General and Administrative Expenses

	For the year ended December 31,	
(In millions)	2013	2012
General and administrative expenses	$594	$504
Selling and marketing expenses	310	303
	$904	$807

General and administrative expenses increased by $90 million for the year ended December 31, 2013, compared to the same period in 2012, which was due primarily to the following:

- Increase in general and administrative costs for GenOn, which was acquired in December 2012, offset by cost savings as a result of realized synergies for the combined company, offset by;
- Impact of prior year EPA settlement regarding LaGen of $14 million and CDWR settlement of $20 million; and
- Impact in prior year of $9 million of transaction costs associated with the sale of 49% of Agua Caliente

Selling and marketing expenses increased due to customer growth efforts and new market expansion, offset in part by the elimination of the Independence Energy sales channel and lower employee costs.

Acquisition-related Transaction and Integration Costs

Transaction and integration costs, primarily in connection with the acquisition of GenOn and consisting mostly of severance costs, increased $21 million for the year ended December 31, 2013, compared to the same period in 2012.

Equity in Earnings of Unconsolidated Affiliates

NRG's equity in earnings of unconsolidated affiliates was $7 million for the year ended December 31, 2013, compared to $37 million for the same period in 2012, primarily resulting from a long-term natural gas hedge entered into by Saguaro in July 2013 as well as additional losses from a hedge associated with the investment in Sherbino and losses associated with certain technology investments.

Bargain purchase gain related to GenOn acquisition

In connection with the acquisition of GenOn in December 2012, the Company recorded a bargain purchase gain of $296 million in the year ended December 31, 2012. The gain is primarily representative of the undiscounted value of the deferred tax assets generated by the reduction in book basis of the net assets recorded in connection with acquisition accounting as well as the undiscounted value of GenOn's net operating losses and other deferred tax benefits that the combined company has the ability to realize in the post-acquisition period.

Impairment Losses on Investments

In the fourth quarter 2013, the Company recorded impairment losses of $99 million, primarily related to the Company's Gladstone equity method investment. The Company determined that losses associated with the investments were other than temporary and accordingly, an impairment loss was recorded. Impairments are discussed in more detail in Item 15 — Note 10, Asset Impairments, to the Consolidated Financial Statements,

Loss on Debt Extinguishment

A loss on debt extinguishment of $50 million was recorded in the year ended December 31, 2013, including $28 million related to open market repurchases of the 2018 Senior Notes, 2019 Senior Notes and 2020 Senior Notes in the first quarter of 2013. These losses primarily consisted of the premiums paid on redemption and the write-off of previously deferred financing costs. In the second quarter of 2013, a $21 million loss on debt extinguishment was recorded and included $11 million related to the redemption of the 2014 GenOn Senior Notes, which consisted of redemption premiums offset by the write-off of the remaining unamortized premium, and $10 million related to the amendments to the Senior Credit Facility, which consisted primarily of the write-off of previously deferred financing costs.

A loss on debt extinguishment of the 2017 Senior Notes of $51 million was recorded in the year ended December 31, 2012, which primarily consisted of the premiums paid on redemption and the write-off of previously deferred financing costs.

Interest Expense

NRG's interest expense increased by $187 million for the year ended December 31, 2013, compared to the same period in 2012 due to the following:

Increase/(decrease) in interest expense	(In millions)
Increase for acquisition of GenOn in December 2012	$203
Increase from additional project financings and the reduction in capitalized interest as projects were placed in service	80
Decrease for 2017 Senior Notes redeemed in September 2012	(60)
Increase for 2023 Senior Notes issued in September 2012	48
Decrease for the repricing of the term loan in 2013	(35)
Decrease for derivative interest expense primarily from losses on Alpine in the prior year compared to gains in the current year	(24)
Other	(25)
Total	$187

Income Tax Benefit

For the year ended December 31, 2013, NRG recorded an income tax benefit of $282 million on pre-tax loss of $634 million. For the same period in 2012, NRG recorded an income tax benefit of $327 million on a pre-tax loss of $12 million. The effective tax rate was 44.5% and 2,725.0% for the years ended December 31, 2013, and 2012, respectively.

For the year ended December 31, 2013, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of ITCs from the Company's Agua Caliente solar project in Arizona of $36 million and production tax credits, or PTCs, generated from Texas wind facilities of $14 million.

	Year Ended December 31,	
	2013	2012
	(In millions except as otherwise stated)	
(Loss)/Income Before Income Taxes	$(634)	$(12)
Tax at 35%	(222)	(4)
State taxes, including changes in rate, net of federal benefit	11	1
Foreign operations	5	(24)
Federal and state tax credits, including investment tax credits (ITC)	(36)	(158)
Valuation allowance	(5)	5
Expiration/utilization of capital losses	10	—
Reversal of valuation allowance on expired/utilized capital losses	(10)	—
Impact of non-taxable entity earnings	(14)	(7)
Bargain purchase gain related to GenOn acquisition	—	(104)
Interest accrued on uncertain tax positions	(3)	2
Production tax credits	(14)	(14)
Reversal of uncertain tax position reserves	(11)	(13)
Tax expense attributable to consolidated partnerships	8	—
Other	(1)	(11)
Income tax benefit	$(282)	$(327)
Effective income tax rate	44.5%	2,725.0%

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in valuation allowances in accordance with ASC 740, Income Taxes, or ASC 740. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Consolidated Results of Operations
2012 compared to 2011
The following table provides selected financial information for the Company:

	Year Ended December 31,		
(In millions except otherwise noted)	2012[(a)]	2011	Change %
Operating Revenues			
Energy revenue [(b)]	$2,114	$2,069	2 %
Capacity revenue [(b)]	762	736	4
Retail revenue	5,888	5,807	1
Mark-to-market for economic hedging activities	(450)	325	238
Contract amortization	(97)	(159)	39
Other revenues [(c)]	205	301	(32)
Total operating revenues	8,422	9,079	(7)
Operating Costs and Expenses			
Generation cost of sales [(b)]	2,123	2,488	(15)
Retail cost of sales [(b)]	2,828	2,815	—
Mark-to-market for economic hedging activities	(182)	169	208
Contract and emissions credit amortization [(d)]	39	47	(17)
Other cost of operations	1,332	1,226	9
Total cost of operations	6,140	6,745	(9)
Depreciation and amortization	950	896	6
Impairment losses	—	160	N/A
Selling, general and administrative	807	586	38
Acquisition-related transaction and integration costs	107	—	100
Development costs	68	57	19
Total operating costs and expenses	8,072	8,444	(4)
Operating Income	350	635	(45)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	37	35	6
Bargain purchase gain related to GenOn acquisition	296	—	100
Impairment losses on investments	(2)	(495)	N/A
Other income, net	19	19	—
Loss on debt extinguishment	(51)	(175)	(71)
Interest expense	(661)	(665)	(1)
Total other expense	(362)	(1,281)	(72)
Loss before income tax expense	(12)	(646)	(98)
Income tax benefit	(327)	(843)	(61)
Net Income	315	197	60
Less: Net income attributable to noncontrolling interest	20	—	100
Net income attributable to NRG Energy, Inc.	$295	$197	50
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	2.79	4.04	(31)%

(a) Includes the results of GenOn from December 15, 2012 to December 21, 2012.
(b) Includes realized gains and losses from financially settled transactions.
(c) Includes unrealized trading gains and losses.
(d) Includes amortization of SO_2 and NO_x credits and excludes amortization of RGGI.
N/A - Not Applicable

Management's discussion of the results of operations for the years ended December 31, 2012 and 2011
Conventional Generation gross margin
The following is a discussion of gross margin for NRG's Conventional Generation businesses, adjusted to eliminate intersegment activity primarily with the Retail Business.

	Year Ended December 31, 2012									
	Conventional Generation									
(In millions except otherwise noted)	Texas	East	South Central	West	Other	Subtotal	Alternative Energy	NRG Yield (a)	Eliminations/Corporate	Consolidated Total
Energy revenue	$2,406	$533	$527	$121	$39	$3,626	$117	$33	$ (1,662)	$ 2,114
Capacity revenue	81	314	240	124	41	800	—	—	(38)	762
Other revenue	28	19	(10)	4	93	134	8	142	(79)	205
Generation revenue	2,515	866	757	249	173	4,560	125	175	(1,779)	$ 3,081
Generation cost of sales	(958)	(440)	(519)	(88)	(78)	(2,083)	—	(58)	$ 18	$ (2,123)
Generation gross margin	$1,557	$426	$238	$161	$95	$2,477	$125	$117		
Business Metrics										
MWh sold (in thousands)(b)	43,707	8,172	17,935	2,146			1,524	464		
MWh generated (in thousands)	37,695	6,469	15,927	2,146			1,524	464		

	Year Ended December 31, 2011									
	Conventional Generation									
(In millions except otherwise noted)	Texas	East	South Central	West	Other	Subtotal	Alternative Energy	NRG Yield (a)	Eliminations/Corporate	Consolidated Total
Energy revenue	$2,545	$579	$548	$31	$58	$3,761	$18	$25	$ (1,735)	$ 2,069
Capacity revenue	28	291	243	118	70	750	—	—	(14)	736
Other revenue	86	26	18	4	58	192	1	138	(30)	301
Generation revenue	2,659	896	809	153	186	4,703	19	163	(1,779)	$ 3,106
Generation cost of sales	(1,228)	(527)	(547)	(16)	(125)	(2,443)	—	(61)	$ 16	$ (2,488)
Generation gross margin	$1,431	$369	$262	$137	$61	$2,260	$19	$102		
Business Metrics										
MWh sold (in thousands)(b)	48,078	9,317	17,131	215			843	420		
MWh generated (in thousands)	45,165	7,361	16,000	215			843	420		

	Year Ended December 31,			
	Texas	East	South Central	West
Weather Metrics				
2012				
CDDs (c)	3,134	754	1,782	904
HDDs (c)	1,452	5,317	2,861	2,988

2011				
CDDs	3,440	750	1,817	717
HDDs	1,911	5,770	3,387	3,364
30 year average				
CDDs	2,692	540	1,554	711
HDDs	1,950	6,206	3,575	3,259

(a) Yield MWh generated excludes thermal facilities.

(b) MWh sold excludes generation at facilities that generate revenue under capacity agreements.

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

Conventional Generation gross margin — increased by $217 million, including intercompany sales, during the year ended December 31, 2012, compared to the same period in 2011, due to:

Increase in Texas region	$126	
Increase in East region	57	
Decrease in South Central region	(24	)
Increase in West region	24	
Other [(a)]	34	
	$217	

(a) Other gross margin primarily represents revenues from the maintenance services business, which are eliminated in consolidation.

The increase in gross margin in the Texas region was driven by:

Impact of fewer unplanned outages during periods of high scarcity pricing as well as more effective hedging and trading optimization activities	$96	
Higher gross margin driven by higher average realized energy prices and a decrease in delivered coal costs	93	
Higher revenue due to additional bi-lateral contracts with load serving entities and contracts with the Retail Business	53	
Lower gross margin from a decrease in coal and nuclear generation driven by more unplanned outage hours in 2012	(73	)
Change in unrealized commercial optimization activities	(56	)
Other	13	
	$126	

The increase in gross margin in the East region was driven by:

Higher gross margin from the acquisition of GenOn in December 2012	$43	
Higher gross margin from favorable pricing on certain load-serving contracts, as well as additional load contracts with the Retail Business	31	
Lower capacity revenue due to 3% lower realized prices, due mainly to an 11% decrease in NEPOOL FCM prices offset in part by an increase in capacity prices in PJM and New York	(19	)
Higher revenue due to RSS contract revenues in western New York.	18	
Lower gross margin from coal plants due primarily to a 15% increase in delivered coal prices	(12	)
Other	(4	)
	57	

The decrease in gross margin in the South Central region was driven by:

Higher gross margin from an increase in gas generation as a result of lower gas prices	$117	
Lower gross margin from a decrease in average realized merchant prices	(61	)
Lower gross margin from decrease in coal generation due to several plants switching from coal to gas generation	(51	)
Change in unrealized commercial optimization activities and other	(29	)
	$(24	)

The increase in gross margin in the West region was driven by:

Higher gross margin from increased run time at Encina driven by competitor's plant outages in the region and increased run time at the remaining plants in the region	$22	
Higher capacity margin due to the recognition of contingent rent for Long Beach	6	
Decreased capacity revenue due to lower pricing and outage penalties for Encina, El Segundo and Cabrillo II	(6	)
Higher gross margin from the acquisition of GenOn in December 2012	6	
Decrease in fuel sales compared to 2011	(4	)
	$24	

Alternative Energy gross margin

NRG's Alternative Energy business segment, which is comprised mainly of the solar and wind businesses that are not part of NRG Yield, had gross margin of $125 million for the year ended December 31, 2012, compared to gross margin of $19 million for the same period in 2011. The increase in gross margin primarily resulted from the addition of the first 230 MW of Agua Caliente, which reached commercial operations in 2012, and the addition of the first 127 MW of the CVSR facility.

NRG Yield gross margin

NRG Yield had gross margin of $117 million for the year ended December 31, 2012 compared to gross margin of $102 million for the same period in 2011, primarily as a result of the Roadrunner project reaching commercial operations in late 2011 and additional revenue from Distributed Solar projects.

Retail gross margin

The following is a discussion of retail gross margin for NRG's Retail Business.

	Year ended December 31,	
(In millions except otherwise noted)	2012	2011
Operating Revenues		
Mass revenues	$3,813	$3,545
Commercial and Industrial revenues	1,929	2,079
Supply management revenues	151	188
Retail operating revenues [(a)(b)]	5,893	5,812
Retail cost of sales [(c)]	4,515	4,558
Retail gross margin	$1,378	$1,254
Business Metrics		
Electricity sales volume — GWh		
Mass [(e)]	31,373	28,035
Commercial and Industrial [(d)]	27,812	28,567
Electricity sales volume — GWh		
Texas	53,451	55,085
All other regions	5,734	1,517
Average retail customers count (in thousands, metered locations)		
Mass	2,054	1,946
Commercial and Industrial [(d)]	91	85
Retail customers count (in thousands, metered locations)		
Mass [(e)]	2,108	1,977
Commercial and Industrial [(d)]	102	91

(a) Includes customers of the Texas General Land Office, for whom the Company provides services, as well as sales to utility partner customers.

(b) Includes intercompany sales of $5 million in both 2012 and 2011, representing sales from Retail to the Texas region.

(c) Includes intercompany purchases of $1,687 million and $1,743 million, respectively.

(d) Includes customers of the Texas General Land Office for which the Company provides services.

(e) Excludes utility partner and natural gas customers.

- Retail gross margin — Retail gross margin increased $124 million for the year ended December 31, 2012, compared to the same period in 2011, driven by:

Gross margin for an additional nine months of Energy Plus as it was acquired in September 2011	$112
Increase in usage and customer count	54
Decrease in unit margins driven by the impact of lower pricing and lower supply costs on acquisitions and renewals	(48)
	27

Favorable impact of fewer scarcity price increases during times of excessive load compared to prior year, partially offset by generally milder weather in 2012	
Unfavorable impact of weather-related risk management activities	(21)
	$124

- Trends — Customer counts increased by approximately 142,000 from 2011 to 2012, which was primarily due to expansion into new territories and marketing efforts. While cooling and heating degree days in both periods resulted in higher than normal customer usage, weather in 2012 was milder than in 2011. The weather resulted in higher customer usage of 4% and 13% in 2012 and 2011, respectively, when compared to ten-year normal weather. In addition, there were increases in Texas in Transmission and Distribution Service Provider rates that will remain in effect for several years. These costs are passed through to Retail customers.

Mark-to-market for Economic Hedging Activities

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges and ineffectiveness on cash flow hedges. Total net mark-to-market results decreased by $424 million in the year ended December 31, 2012, compared to the same period in 2011.

The breakdown of gains and losses included in operating revenues and operating costs and expenses by region are as follows:

	Year Ended December 31, 2012						
	Retail	Texas	East	South Central	West	Elimination [(a)]	Total
	(In millions)						
Mark-to-market results in operating revenues							
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(7)	$(501)	$2	$40	$8	$ 19	$(439)
Reversal of gain positions acquired as part of the GenOn acquisition	—	—	(13)	—	—	—	$(13)
Net unrealized gains/(losses) on open positions related to economic hedges	2	60	(1)	(10)	2	(51)	2
Total mark-to-market (losses)/gains in operating revenues	$(5)	$(441)	$(12)	$30	$10	$ (32)	$(450)
Mark-to-market results in operating costs and expenses							
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$181	$15	$12	$3	$—	$ (19)	$192
Reversal of loss positions acquired as part of the Reliant Energy and Green Mountain Energy acquisitions	24	—	9	—	—	—	33
Net unrealized losses on open positions related to economic hedges	(34)	(38)	(6)	(16)	—	51	(43)
Total mark-to-market gains/(losses) in operating costs and expenses	$171	$(23)	$15	$(13)	$—	$ 32	$182

(a) Represents the elimination of the intercompany activity between the Retail Business and the Conventional Generation regions.

Mark-to-market results consist of unrealized gains and losses. The settlement of these transactions is reflected in the same caption as the items being hedged.

For the year ended December 31, 2012, the net losses on open positions were due primarily to decreases in forward coal prices.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the years ended December 31, 2012, and 2011. The realized and unrealized financial and physical trading results are included in operating revenues. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Year Ended December 31,	
	2012	2011
	(In millions)	
Trading gains/(losses)		
Realized	$83	$(31)
Unrealized	(14)	63
Total trading gains	$69	$32

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase accounting and the favorable change of $62 million, as compared to 2011, related primarily to lower contract amortization of $43 million and $19 million for Reliant Energy and Green Mountain Energy, respectively.

Other Operating Costs

	Retail	Texas	East	South Central	West	Other	Alternative Energy	NRG Yield	Corporate/Eliminations	Total
	(In millions)									
Year ended December 31, 2012	$241	$559	$274	$118	$67	$68	$18	$53	$ (66)	$1,332
Year ended December 31, 2011	$216	$515	$253	$112	$60	$34	$15	$47	$ (26)	$1,226

Other operating costs increased by $106 million for the year ended December 31, 2012, compared to the same period in 2011, due to:

	(In millions)
Increase in Retail operations and maintenance expense	$25
Increase in Texas region operations and maintenance expense	44
Increase in East region operations and maintenance expense	16
Increase in Alternative Energy and NRG Yield operations and maintenance expense	9
Increase in property tax expense and other	12
	$106

Retail operations and maintenance expense — increased $12 million due to the acquisition of Energy Plus in September 2011 and approximately $13 million due to expansion into new markets, products and channels.

Texas operations and maintenance — increased primarily due to maintenance spending and outage work in 2012 at Limestone and W.A. Parish as well as additional costs at S.R. Bertron to return two units to service.

East operations and maintenance expense — increased due to additional costs of $30 million from the acquisition of GenOn, offset by a decrease in part because the prior year reflects incremental costs associated with headcount reductions.

Alternative Energy and NRG Yield operations and maintenance expense — increased as additional solar facilities, including 253 MW of Agua Caliente and 127 MW of CVSR, and Roadrunner began commercial operations in late 2011 and in 2012.

Property tax expense — increased primarily for $5 million in the East region due to a reduction in property tax benefit from the New York State Empire Zone program, which reflects a change in the criteria used in determining the amount of the tax credit and an annual reduction of 20%. The remaining increases are primarily due to the acquisition of GenOn.

Depreciation and Amortization

NRG's depreciation and amortization expense increased by $54 million during the year ended December 31, 2012, compared to the same period in 2011. This was primarily due to additional depreciation related to solar facilities which commenced commercial operations in late 2011 and in 2012, as well as additional depreciation in the East due to Indian River AQCS assets placed in service and the acquisition of GenOn.

Impairment Losses

As described in Item 15 — Note 24, Environmental Matters, the Company recorded an impairment loss of $160 million in the year ended December 31, 2011, on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment loss reflects the write-off of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $221 million during the year ended December 31, 2012, compared to the same period in 2011, which was primarily due to:

- Selling, general and administrative costs of $66 million for an additional nine months of Energy Plus which was acquired in September 2011;
- Cash payment related to the CDWR settlement of $20 million expensed during the period and paid in January 2013;
- Transaction costs of $9 million associated with the sale of 49% of Agua Caliente;
- Increase in marketing and selling costs of $51 million associated with customer growth efforts and new market expansion by corporate and the Retail Business;
- Increase of $13 million related to additional solar projects and acquired Distributed Solar businesses;
- The impact of a settlement with the EPA regarding LaGen of $14 million; and
- Additional costs associated with new business initiatives of $13 million, consulting and legal costs of $15 million and $16 million of additional labor costs, as well an additional $7 million of expense incurred in the post-acquisition period as GenOn was acquired in December 2012.

Acquisition-related Transaction and Integration Costs

NRG acquired GenOn in December 2012. In connection with the transaction, NRG incurred transaction and integration costs of $107 million in the year ended December 31, 2012, consisting primarily of severance associated with headcount reductions, financial consulting fees and legal expenses.

Bargain purchase gain related to GenOn acquisition

In connection with the acquisition of GenOn in December 2012, the Company recorded a bargain purchase gain of $296 million in the year ended December 31, 2012. The gain is primarily representative of the undiscounted value of the deferred tax assets generated by the reduction in book basis of the net assets recorded in connection with acquisition accounting as well as the undiscounted value of GenOn’s net operating losses and other deferred tax benefits that the combined company has the ability to realize in the post-acquisition period.

Impairment Losses on Investments

As discussed in more detail in Item 15 — Note 10, Asset Impairments, to the Consolidated Financial Statements, the March 2011 earthquake and tsunami in Japan, which in turn triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station, caused NRG to evaluate its investment in NINA for impairment. Consequently, NRG deconsolidated its investment in NINA and took an impairment charge in the first quarter of 2011 equal to the balance of its investment in NINA. To support NINA's ongoing work, NRG contributed an additional $14 million into NINA during the year ended December 31, 2011. As a result, NRG recorded an impairment charge of $495 million in the year ended December 31, 2011. During the year ended December 31, 2012, NRG contributed an additional $2 million and recorded this amount as an impairment charge.

Loss on Debt Extinguishment

A loss on debt extinguishment of the 2017 Senior Notes of $51 million was recorded in the year ended December 31, 2012, while a loss on debt extinguishment of the 2014 Senior Notes, the 2016 Senior Notes and the senior credit facility of $175 million was recorded in the year ended December 31, 2011. These losses primarily consisted of the premiums paid on redemption and the write-off of previously deferred financing costs.

Interest Expense

NRG's interest expense decreased by $4 million during the year ended December 31, 2012, compared to the same period in 2011, due to the following:

	(In millions)
Increase/(decrease) in interest expense	
Increase for 2023 Senior Notes issued in September 2012	$18
Increase for 2018 Senior Notes issued in January of 2011 and 2019 and 2021 Senior Notes issued in May of 2011	65
Decrease for 2017 Senior Notes redeemed in September 2012	(20)
Decrease for 2014 Senior Notes and 2016 Senior Notes redeemed in 2011	(82)
Decrease for higher capitalized interest	(58)
Increase from additional project financings	47
Increase in derivative interest expense primarily for the Alpine interest rate swaps	10
Increase for GenOn senior notes	9
Other	7
Total	$(4)

Income Tax Benefit

For the year ended December 31, 2012, NRG recorded an income tax benefit of $327 million on pre-tax loss of $12 million. For the same period in 2011, NRG recorded an income tax benefit of $843 million on a pre-tax loss of $646 million. The effective tax rate was 2,725.0% and 130.5% for the year ended December 31, 2012, and 2011, respectively.

For the year ended December 31, 2012, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of ITCs from the Company's Agua Caliente solar project in Arizona of $158 million, a benefit of $104 million resulting from the gain on bargain purchase of GenOn, and the PTCs generated from certain Texas wind facilities of $14 million.

	Year Ended December 31,	
	2012	2011
	(In millions except as otherwise stated)	
Income/(Loss) Before Income Taxes	$(12)	$(646)
Tax at 35%	(4)	(226)
State taxes, including changes in rate, net of federal benefit	1	15
Foreign operations	(24)	(3)
Federal and state tax credits	(158)	(1)
Valuation allowance	5	(63)
Expiration/utilization of capital losses	—	45
Reversal of valuation allowance on expired/utilized capital losses	—	(45)
Foreign earnings	—	4
Impact of non-taxable entity earnings	(7)	—
Bargain purchase gain related to GenOn acquisition	(104)	—
Interest accrued on uncertain tax positions	2	2
Production tax credits	(14)	(14)
Reversal of uncertain tax position reserves	(13)	(561)
Other	(11)	4
Income tax benefit	$(327)	$(843)
Effective income tax rate	2,725.0%	130.5%

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in valuation allowances in accordance with ASC 740, Income Taxes, or ASC 740. These factors and others, including the Company's history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2013 and 2012, NRG's liquidity, excluding collateral received, was approximately $3.7 billion and $3.4 billion, respectively, comprised of the following:

	As of December 31,	
	2013	2012
	(In millions)	
Cash and cash equivalents	$2,254	$2,087
Restricted cash	268	217
Total	2,522	2,304
Total credit facility availability	1,173	1,058
Total liquidity, excluding collateral received	$3,695	$3,362

For the year ended December 31, 2013, total liquidity, excluding collateral received, increased by $333 million. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading Cash Flow Discussion. Cash and cash equivalents at December 31, 2013 were predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

Management believes that the Company's liquidity position and cash flows from operations will be adequate to finance operating and maintenance capital expenditures, to fund dividends to NRG's common and preferred stockholders, and other liquidity commitments. Management continues to regularly monitor the Company's ability to finance the needs of its operating, financing and investing activity within the dictates of prudent balance sheet management.

Restricted Payments Tests

The ability of certain of GenOn's and GenOn Americas Generation's subsidiaries to pay dividends and make distributions is restricted under the terms of certain agreements, including the Gen-On Mid-Atlantic and REMA operating leases. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. At December 31, 2013, GenOn Mid Atlantic and REMA did not satisfy the restricted payments tests.

The GenOn Senior Notes due 2018 and 2020 and the related indentures restrict the ability of GenOn to incur additional liens and make certain restricted payments, including dividends. In the event of a default or if restricted payment tests are not satisfied, GenOn would not be able to distribute cash to its parent, NRG. At December 31, 2013, GenOn did not meet the consolidated debt ratio component of the restricted payments test and, therefore, the ability of GenOn to make restricted payments, including dividends, loans and advances to NRG, is limited to specified exclusions, including up to $250 million of such restricted payments.

Credit Ratings

Credit rating agencies rate a firm's public debt securities. These ratings are utilized by the debt markets in evaluating a firm's credit risk. Ratings influence the price paid to issue new debt securities by indicating to the market the Company's ability to pay principal, interest and preferred dividends. Rating agencies evaluate a firm's industry, cash flow, leverage, liquidity, and hedge profile, among other factors, in their credit analysis of a firm's credit risk.

The following table summarizes the credit ratings for NRG Energy, Inc., its Term Loan Facility and its Senior Notes, GenOn Senior Notes, and GenOn Americas Generation Senior Notes as of December 31, 2013:

	S&P	Moody's
NRG Energy, Inc.	BB- Stable	Ba3 Stable
7.375% Senior Notes, due 2017	BB-	B
7.625% Senior Notes, due 2018	BB-	B
7.625% Senior Notes, due 2019	BB-	B
8.5% Senior Notes, due 2019	BB-	B
8.25% Senior Notes, due 2020	BB-	B
7.875% Senior Notes, due 2021	BB-	B
6.625% Senior Notes, due 2023	BB-	B
Term Loan Facility, due 2018	BB+	Baa3
GenOn 7.875% Senior Notes, due 2017	B	B3(a)
GenOn 9.500% Senior Notes, due 2018	B	B3(a)
GenOn 9.875% Senior Notes, due 2020	B	B3(a)
GenOn Americas Generation 8.500% Senior Notes, due 2021	BB-	B3(a)
GenOn Americas Generation 9.125% Senior Notes, due 2031	BB-	B3(a)

(a) On January 24, 2014, Moody’s placed GenOn’s ratings under review for downgrade.

Sources of Liquidity

The principal sources of liquidity for NRG's future operating and capital expenditures are expected to be derived from new and existing financing arrangements, existing cash on hand, cash flows from operations and cash proceeds from futures sales of assets to NRG Yield, Inc. As described in Item 15 — Note 12, Debt and Capital Leases, to the Consolidated Financial Statements, the Company's financing arrangements consist mainly of the Senior Credit Facility, the Senior Notes, the GenOn Senior Notes, the GenOn Americas Generation Senior Notes, and project-related financings.

Issuance of 2022 Senior Notes

On January 27, 2014, NRG issued $1.1 billion in aggregate principal amount at par of 6.25% Senior Notes due 2022. The notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest is payable semi-annually beginning on July 15, 2014, until the maturity date of July 15, 2022. A portion of the cash proceeds was used to redeem $400 million of the Company's Senior Notes as discussed in Uses of Liquidity and the remaining $700 million of the cash proceeds is expected to be used to finance the EME acquisition.

Cash Proceeds from Future Sales of Assets to NRG Yield, Inc.

The Company expects to offer NRG Yield, Inc. the right to acquire certain of its assets in 2014, including El Segundo Energy Center, High Desert and Kansas South. The cash portion of any consideration to be paid to NRG by NRG Yield, Inc. for these assets has yet to be determined.

First Lien Structure

In addition, NRG has granted first liens to certain counterparties on substantially all of the Company's assets, excluding assets acquired in the GenOn acquisition and NRG's assets that have project-level financing. NRG uses the first lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or gas used as a proxy for power. To the extent that the underlying hedge positions for a counterparty are out-of-the-money to NRG, the counterparty would have claim under the lien program. The lien program limits the volume that can be hedged, not the value of underlying out-of-the-money positions. The first lien program does not require NRG to post collateral above any threshold amount of exposure. Within the first lien structure, the Company can hedge up to 80% of its coal and nuclear capacity, excluding GenOn coal capacity, and 10% of its other assets, excluding GenOn's other assets, with these counterparties for the first 60 months and then declining thereafter. Net exposure to a counterparty on all trades must be positively correlated to the price of the relevant commodity for the first lien to be available to that counterparty. The first lien structure is not subject to unwind or termination upon a ratings downgrade of a counterparty and has no stated maturity date.

The Company's lien counterparties may have a claim on its assets to the extent market prices exceed the hedged prices. As of December 31, 2013, all hedges under the first liens were out-of-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MWs hedged against the Company's coal and nuclear assets and as a percentage relative to the Company's coal and nuclear capacity under the first lien structure as of December 31, 2013:

Equivalent Net Sales Secured by First Lien Structure [a]	2014	2015	2016	2017
In MW [b]	1,747	938	373	209
As a percentage of total net coal and nuclear capacity [c]	26 %	15 %	6 %	3 %

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

(b) 2014 MW value consists of February through December positions only.

(c) Net coal and nuclear capacity represents 80% of the Company's total coal and nuclear assets eligible under the first lien, which excludes coal assets acquired in the GenOn acquisition.

Uses of Liquidity

The Company's requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (i) commercial operations activities; (ii) debt service obligations, as described more fully in Item 15 — Note 12, Debt and Capital Leases, to the Consolidated Financial Statements; (iii) capital expenditures, including repowering and renewable development, and environmental; and (iv) corporate transactions including return of capital and dividend payments to stockholders, as described in Item 15 — Note 15, Capital Structure, to the Consolidated Financial Statements.

Commercial Operations

The Company's commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) margin and collateral required to participate in physical markets and commodity exchanges; (iii) timing of disbursements and receipts (i.e. buying fuel before receiving energy revenues); (iv) initial collateral for large structured transactions; and (v) collateral for project development. As of December 31, 2013, commercial operations had total cash collateral outstanding of $276 million, and $902 million outstanding in letters of credit to third parties primarily to support its commercial activities for both wholesale and retail transactions (includes a $37 million letter of credit relating to deposits at the PUCT that cover outstanding customer deposits and residential advance payments). As of December 31, 2013, total collateral held from counterparties was $63 million in cash, and $6 million of letters of credit.

Future liquidity requirements may change based on the Company's hedging activities and structures, fuel purchases, and future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on the Company's credit ratings and general perception of its creditworthiness.

Cash Grant Bridge Loans

As of December 31, 2013, the Company has submitted applications for reimbursement of approximately $539 million, in the aggregate, net of sequestration adjustment, with the U.S. Treasury under the 1603 Cash Grant Program in connection with the following projects: CVSR, Alpine, Borrego, High Desert, Kansas South, Lincoln Financial Field, Gillette Stadium, and various Distributed Solar projects. The Company expects to submit applications for reimbursement of approximately $558 million, in the aggregate, net of sequestration adjustment, with the U.S. Treasury under the 1603 Cash Grant Program for Ivanpah and upon completion of various Distributed Solar projects. With respect to certain projects, the Company obtained cash grant bridge loans to fund the construction costs of such projects, which were to be repaid upon receipt of the related cash grant proceeds. As of December 31, 2013, there are approximately $854 million outstanding under the cash grant bridge loans, which will become due and payable as follows:

Three months ending:	Cash due and payable (In millions)
March 31, 2014	$228
June 30, 2014	202
September 30, 2014	176
December 31, 2014	117
March 31, 2015	132
Total cash grant bridge loans due, including interest accrued to principal	$855

The Company has complied with all obligations under the 1603 Cash Grant Program and is working with the U.S. Treasury Department to obtain payment on the 1603 applications the Company or its subsidiaries have submitted. In January 2014, the Company was awarded a cash grant for the CVSR project in the amount of $307 million, which is approximately 75% of the anticipated cash grant as applied for by the Company, and received $285 million as a result of sequestration. NRG is evaluating the basis for the award and all of its options for recovering the full amount to which the Company believes it is entitled. In January 2014, the Company was awarded the full cash grant of $72 million as applied for, relating to the Alpine project, and has received the post-sequestration funds of $66 million.

Debt Service Obligations

Principal payments on debt and capital leases as of December 31, 2013, are due in the following periods:

Description	2014	2015	2016	2017	2018	Thereafter	Total
	(In millions)						
NRG Recourse Debt:							
Senior notes, due 2018	$—	$—	$—	$—	$1,130	$—	$1,130
Senior notes, due 2019	—	—	—	—	—	800	800
Senior notes, due 2019	—	—	—	—	—	607	607
Senior notes, due 2020	—	—	—	—	—	1,062	1,062
Senior notes, due 2021	—	—	—	—	—	1,128	1,128
Senior notes, due 2023	—	—	—	—	—	990	990
Term loan facility, due 2018	20	20	20	21	1,926	—	2,007
Indian River Power LLC, tax exempt bonds, due 2040 and 2045	—	—	—	—	—	247	247
Dunkirk Power LLC, tax exempt bonds, due 2042	—	—	—	—	—	59	59
Fort Bend County, tax-exempt bonds, due 2038 and 2042	1	—	—	—	—	66	67
Subtotal NRG Recourse Debt	21	20	20	21	3,056	4,959	8,097
NRG Non-Recourse Debt:							
GenOn senior notes, due 2017	—	—	—	725	—	—	725
GenOn senior notes, due 2018	—	—	—	—	675	—	675
GenOn senior notes, due 2020	—	—	—	—	—	550	550
GenOn Americas Generation senior notes, due 2021	—	—	—	—	—	450	450
GenOn Americas Generation senior notes, due 2031	—	—	—	—	—	400	400
NRG Marsh Landing senior secured term loans, due 2017 and 2023 [(b)]	42	43	45	47	49	247	473
CVSR - High Plains Ranch II LLC, due 2037 [(a)]	348	18	19	23	25	671	1,104
NRG West Holdings LLC, term loan, due 2023	32	37	41	40	45	317	512
Agua Caliente Solar, LLC, due 2037	24	28	28	29	30	738	877
Ivanpah financing, due 2014 and 2038 [(a)]	407	33	36	39	40	1,019	1,574
South Trent Wind LLC, financing agreement, due 2020 [(b)]	4	4	4	4	4	49	69
NRG Peaker Finance Co. LLC, bonds, due 2019	29	31	33	35	19	19	166
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013, 2017, and 2025 [(b)]	7	12	12	13	8	75	127
NRG Solar Alpine, due 2014 and 2022 [(b)]	69	7	8	8	7	122	221
NRG Solar Borrego I LLC, due 2024 and 2038 [(b)]	3	3	3	2	2	65	78
NRG Solar Avra Valley LLC [(b)]	3	3	3	3	3	48	63
TA - High Desert LLC, due 2023 and 2033	25	3	3	3	3	43	80
NRG Solar Kansas South LLC, due 2031	23	2	2	2	2	26	57
Other [(c)]	13	14	17	42	11	109	206
Subtotal NRG Non-Recourse Debt	1,029	238	254	1,015	923	4,948	8,407
Capital Lease:							

Chalk Point capital lease, due 2015	5	5	—	—	—	—	10
Other Capital Leases	—	—	—	1	1	1	3
Subtotal NRG Capital Leases	5	5	—	1	1	1	13
Total Debt and Capital Leases	$1,055	$263	$274	$1,037	$3,980	$9,908	$16,517

(a) Principal payments in 2014 include the expected repayment of cash grant loans upon receipt of cash grants.

(b) Debt related to projects in NRG Yield

(c) Includes $102M of debt related to projects in NRG Yield

In addition to the debt and capital leases shown in the preceding table, NRG had issued $1.3 billion of letters of credit under the Company's $2.5 billion Revolving Credit Facility as of December 31, 2013.

Capital Expenditures

The following tables and descriptions summarize the Company's capital expenditures, including accruals, for maintenance, environmental, and growth investments, for the year ended December 31, 2013, and the estimated capital expenditure and growth investments forecast for 2014.

	Maintenance	Environmental	Growth Investments	Total
	(In millions)			
East	$148	$68	$—	$216
Texas	118	3	—	121
South Central	42	33	—	75
West	6	—	133	139
Other Conventional	5	1	5	11
Alternative Energy	—	—	1,146	1,146
Retail	30	—	—	30
Yield	8	—	229	237
Corporate	12	—	—	12
Total cash capital expenditures for the year ended December 31, 2013	369	105	1,513	1,987
Other investments[a]	—	—	111	111
Funding from debt financing, net of fees	(13)	(1)	(1,294)	(1,308)
Funding from third party equity partners	—	—	(89)	(89)
Total capital expenditures and investments, net	$356	$104	$241	$701
Estimated capital expenditures for 2014	$395	$232	$650	$1,277
Other investments[a]	—	—	375	375
Funding from debt financing, net of fees	(38)	—	(448)	(486)
Funding from third party equity partners	—	—	(247)	(247)
NRG estimated capital expenditures for 2014, net of financings	$357	$232	$330	$919

(a) Other investments includes restricted cash activity and proceeds from cash grants.

- Maintenance and Environmental capital expenditures — For the year ended December 31, 2013, the Company's environmental capital expenditures included $38 million related to the upgrades at Conemaugh including the installation of selective catalytic reduction technology on both units for enhanced mercury oxidation and removal as well as reduction in NO_x emissions and the completion of upgrades to the existing flue-gas desulfurization systems for enhanced performance.
- Growth Investments capital expenditures — For the year ended December 31, 2013, the Company's growth investment expenditures included $1.2 billion for solar projects and $279 million for the Company's other growth projects.

Environmental Capital Expenditures Estimate

Based on current (and in some cases proposed) rules, technology and preliminary plans based on some proposed rules, NRG estimates that environmental capital expenditures from 2014 through 2018 required to comply with environmental laws will be approximately $332 million, which includes $120 million for GenOn facilities. These costs are primarily associated with (i) controls to satisfy MATS and recent NSR settlement at Big Cajun II; (ii) controls to satisfy MATS at W.A. Parish, Limestone and Conemaugh; and (iii) NO_x controls for Sayreville and Gilbert. In connection with the proposed acquisition of EME, the Company expects to incur additional environmental capital expenditures. NRG continues to explore cost-effective compliance alternatives to further reduce costs.

NRG's current contracts with the Company's rural electric cooperative customers in the South Central region allow for recovery of a portion of the region's capital costs once in operation, along with a capital return, incurred by complying with any change in law, including interest over the asset life of the required expenditures. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

The table below summarizes the status of NRG's coal fleet with respect to air quality controls. Planned investments are either in construction or budgeted in the existing capital expenditures budget. Changes to regulations could result in changes to planned installation dates. NRG uses an integrated approach to fuels, controls and emissions markets to meet environmental standards.

Units [a]	SO_2 Control Equipment	Install Date	NO_x Control Equipment	Install Date	Mercury Control Equipment	Install Date	Particulate Control Equipment	Install Date
Huntley 67	DSI/FF	2009	LNBOFA/SNCR	1994/2009	ACI	2009	FF	2009
Huntley 68	DSI/FF	2009	LNBOFA/SNCR	1995/2009	ACI	2009	FF	2009
Dunkirk 1	DSI/FF	2010	LNBOFA/SNCR	1994/2010	ACI	2010	FF	2010
Dunkirk 2	DSI/FF	2010	LNBOFA/SNCR	1993/2010	ACI	2010	FF	2010
Dunkirk 3	DSI/FF	2009	LNBOFA/SNCR	1994/2009	ACI	2009	FF	2009
Dunkirk 4	DSI/FF	2009	LNBOFA/SNCR	1994/2009	ACI	2009	FF	2009
Chalk Point 1	FGD	2009	SCR	2008	FGD/ESP	2009	ESP/upgrade	1964/1980
Chalk Point 2	FGD	2009	SACR	2006	FGD/ESP	2009	ESP/upgrade	1964/1980
Dickerson 1-3	FGD	2009	SNCR	2009	FGD/FF	2009	ESP/FF	1959,1960,196
Morgantown 1-2	FGD	2009	SCR	2007-2008	FGD/ESP	2009	ESP	1970, 1971
Cheswick 1	FGD	2010	SCR	2003	FGD/ESP	2010	ESP	1970
Conemaugh 1-2	FGD	1994, 95	SCR	2014	FGD/ESP/SCR	1994,95/2015	ESP	1970, 1971
Keystone 1-2	FGD	2009	SCR	2003	FGD/ESP	2009	ESP	1967, 1968
Seward	FBL/CDS	2004	SNCR	2004	FBL/FF	2004	FF	2004
Indian River 4	CDS	2011	LNBOFA/SCR	1999/2011	ACI	2008	ESP/FF	1980/2011
Big Cajun II 1	DSI	2015	LNBOFA/ SNCR	2005/2014	ACI	2015	ESP/upgrade	1981/2015
Big Cajun II 2	Gas Conversion	2014	LNBOFA/ SNCR	2004/2014	Gas Conversion	2014	ESP	1981
Big Cajun II 3	PAL	2013	LNBOFA/ SNCR	2002/2014	ACI	2015	ESP/upgrade	1983/2015
Limestone 1-2	Wet Scrubbers	1985-86	LNBOFA/ SNCR	2002/2017	ACI	2015	ESP	1985-1986
W.A. Parish 5, 6, 7	FF co-benefit	1988	SCR	2004	ACI	2015	FF	1988
W.A. Parish 8	Wet Scrubber	1982	SCR	2004	ACI	2015	FF	1988

(a) NRG plans to add natural gas capabilities at its Avon Lake, New Castle, Dunkirk, and Big Cajun II facilities and intends to retire the coal units at Portland and Shawville in 2014 and 2015, respectively. NRG retired all Titus coal units and Indian River Unit 3 in 2013.

ACI - Activated Carbon Injection
CDS - Circulating Dry Scrubber
DSI - Dry Sorbent Injection with Trona
ESP - Electrostatic Precipitator
FGD - Flue Gas Desulfurization (wet)
FBL - Fluidized Bed Limestone Injection
LNBOFA - Low NO_x Burner with Overfire Air
PAL - Plant Average Limit
SCR - Selective Catalytic Reduction
SACR - Selective Auto-Catalytic Reduction

FF- Fabric Filter
SNCR - Selective Non-Catalytic Reduction

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

	Texas	East - legacy NRG	East - GenOn	South Central	Total
	(in millions)				
2014	$25	$5	$84	$118	$232
2015	21	1	27	25	74
2016	16	—	4	—	20
2017	—	—	1	—	1
2018	—	1	4	—	5
Total	$62	$7	$120	$143	$332

NRG's current contracts with the Company's rural electrical customers in the South Central region allow for recovery of a portion of the regions' capital costs once in operation, along with a capital return incurred by complying with any change in law, including interest over the asset life of the required expenditures. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

Corporate Transactions

With respect to the proposed acquisition of EME, the Company expects to pay an aggregate purchase price of $2.6 billion (subject to adjustment), which will be partially financed by the cash proceeds from the issuance of the $700 million of 2022 Senior Notes and the issuance of 12,671,977 shares of NRG common stock (valued at $350 million based upon the volume-weighted average trading price over the 20 trading days prior to October 18, 2013) with the balance to be paid in cash The remaining purchase price is expected to be funded by cash on hand, including acquired cash on hand of $1.1 billion. In connection with the acquisition, the Company also expects to assume debt related to acquired project assets of approximately $1.5 billion, which will be non-recourse to NRG. The proposed acquisition of EME is further described in Note 3, Business Acquisitions and Dispositions.

2013 Capital Allocation Program

During the first quarter of 2013, the Company paid $80 million, $104 million, and $42 million at an average price of 114.179%, 111.700%, and 113.082% of face value, for open market repurchases of the Company's 2018 Senior Notes, 2019 Senior Notes, and 2020 Senior Notes, respectively.

In June 2013, the Company redeemed all of its 2014 GenOn Senior Notes, which had an aggregate outstanding principal amount of $575 million, at a redemption price of 106.778% as well as any accrued and unpaid interest as of the redemption date, with the proceeds of the additional Term Loan Facility borrowings and cash on hand.

In August 2013, the Company increased the annual common stock dividend by 33%, to $0.48 per share. The following table lists the dividends paid during 2013:

	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Fourth Quarter 2013
Dividends per Common Share	$0.09	$0.12	$0.12	$0.12

The Company was authorized to repurchase $200 million of its common stock in 2013 under the 2013 Capital Allocation Program. During the first quarter, the Company purchased 972,292 shares of NRG common stock for approximately $25 million at an average cost of $25.88 per share. As a result of the proposed acquisition of EME, the Company did not complete the remaining $175 million of share repurchases under the 2013 Capital Allocation Program.

The Company's common stock dividend and share repurchases are subject to available capital, market conditions, and compliance with associated laws and regulations.

2014 Capital Allocation Program

On February 17, 2014, NRG paid a quarterly dividend on the Company's common stock of $0.12 per share.

On February 28, 2014, the Company announced its intention to increase NRG's annual common stock dividend by 17% from $0.48 to $0.56 per share, commencing with the next quarterly payment.

On February 10, 2014, the Company redeemed $308 million of its 8.5% 2019 Senior Notes and $91 million of its 7.625% Senior Notes through a tender offer and call, at an average early redemption percentage of 106.992% and 105.500%, respectively, with a portion of the proceeds from the 2022 Senior Notes borrowing.

Share repurchases and debt reduction under the 2014 Capital Allocation Program are subject to market prices, financial restrictions under the Company's debt facilities, securities laws, and the proposed acquisition of EME.

Preferred Stock Dividend Payments

For the year ended December 31, 2013, NRG paid $9 million in dividend payments to holders of the Company's 3.625% Preferred Stock.

Cash Flow Discussion

The following table reflects the changes in cash flows for the comparative years:

(In millions)			
Year ended December 31,	2013	2012	Change
Net cash provided by operating activities	$1,270	$1,149	$121
Net cash used by investing activities	(2,528)	(2,262)	(266)
Net cash provided by financing activities	1,427	2,099	(672)

Net Cash Provided By Operating Activities

Changes to net cash provided by operating activities were driven by:	
Increase in operating income adjusted for non-cash items	$482
Change in cash paid in support of risk management activities	(278)
Other changes in working capital	(83)
	$121

Net Cash Used By Investing Activities

Changes to net cash used by investing activities were driven by:	
Decrease in capital expenditures due to reduced spending on growth projects	$1,409
Increase in cash paid for acquisitions, which primarily reflects the acquisitions of High Desert, Kansas South, and Gregory in 2013	(413)
Cash acquired in 2012 from GenOn acquisition	(983)
Increase in restricted cash, which mainly supports equity requirements for U.S. DOE funded projects	(146)
Decrease in proceeds from sale of assets, primarily related to the sale of Schkopau in 2012	(124)
Other	(9)
	$(266)

Net Cash Provided By Financing Activities

Changes in net cash provided by financing activities were driven by:	
Net increase in debt payments primarily related to open market repurchases of Senior Notes and redemption of GenOn Senior Notes	$(1,063)
Increase in net receipts from settlement of acquired derivatives that include financing elements primarily from the acquisition of GenOn	335
Increase in proceeds from noncontrolling interest related primarily to NRG Yield, Inc. IPO	184
Payment of dividends to common stockholders in 2013	(104)
Cash paid for repurchase of treasury stock in 2013	(25)
Other	1
	$(672)

NOLs, Deferred Tax Assets and Uncertain Tax Position Implications, under ASC 740

As of December 31, 2013, the Company had a domestic pre-tax book loss of $549 million and foreign pre-tax book loss of $85 million. For the year ended December 31, 2013, the Company generated an NOL of $1.4 billion which is available to offset taxable income in future periods. As of December 31, 2013, the Company has cumulative domestic Federal NOL carryforwards of $3.1 billion and cumulative state NOL carryforwards of $3.0 billion for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $270 million, of which $15 million will expire through 2016 and of which $255 million do not have an expiration date.

In addition to these amounts, the Company has $115 million of tax effected uncertain tax benefits. As a result of the Company's tax position, and based on current forecasts, NRG anticipates income tax payments, primarily due to state and local jurisdictions, of up to $50 million in 2014.

However, as the position remains uncertain for the $115 million of tax effected uncertain tax benefits, the Company has recorded a non-current tax liability of $61 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $61 million non-current tax liability for uncertain tax benefits is primarily from positions taken on various state returns, including accrued interest.

Prior to the GenOn acquisition in December 2012, the Company was not subject to U.S. federal income tax examinations for years prior to 2007. GenOn is no longer subject to U.S. federal income tax examinations for years prior to 2010. With few exceptions, state and local income tax examinations are no longer open for years before 2007. The Company's significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2008.

Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See also Item 15 — Note 26, Guarantees, to the Consolidated Financial Statements for additional discussion.

Retained or Contingent Interests

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

Derivative Instrument Obligation

The Company's 3.625% Preferred Stock includes a feature which is considered an embedded derivative per ASC 815. Although it is considered an embedded derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to ASC 815. As of December 31, 2013, based on the Company's stock price, the embedded derivative was out-of-the-money and had no redemption value. See also Item 15 — Note 15, Capital Structure, to the Consolidated Financial Statements for additional discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments — As of December 31, 2013, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy-related entities that are accounted for under the equity method of accounting. Several of these investments are variable interest entities for which NRG is not the primary beneficiary. NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $273 million as of December 31, 2013. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 15 — Note 16, Investments Accounted for by the Equity Method and Variable Interest Entities, to the Consolidated Financial Statements for additional discussion.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs. The following tables summarize NRG's contractual obligations and contingent obligations for guarantee. See also Item 15 — Note 12, Debt and Capital Leases, Note 22, Commitments and Contingencies, and Note 26, Guarantees, to the Consolidated Financial Statements for additional discussion.

	By Remaining Maturity at December 31, 2013					
Contractual Cash Obligations	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total [(a)]	2012 Total
	(In millions)					
Long-term debt (including estimated interest)	$2,066	$2,509	$6,797	$12,108	$23,480	$22,772
Capital lease obligations (including estimated interest)	6	6	1	2	15	16
Operating leases	273	518	446	1,224	2,461	2,880
Fuel purchase and transportation obligations	963	526	356	719	2,564	3,126
Fixed purchased power commitments	24	30	11	—	65	77
Pension minimum funding requirement [(b)]	82	115	118	115	430	475
Other postretirement benefits minimum funding requirement [(c)]	11	24	27	82	144	86
Other liabilities [(d)]	150	249	163	661	1,223	1,235
Total	$3,575	$3,977	$7,919	$14,911	$30,382	$30,667

(a) Excludes $60 million non-current payable relating to NRG's uncertain tax benefits under ASC 740 as the period of payment cannot be reasonably estimated. Also excludes $629 million of asset retirement obligations which are discussed in Item 15 — Note 13, Asset Retirement Obligations, to the Consolidated Financial Statements.

(b) These amounts represent the Company's estimated minimum pension contributions required under the Pension Protection Act of 2006. These amounts represent estimates that are based on assumptions that are subject to change.

(c) These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2020 are currently not available.

(d) Includes water right agreements, service and maintenance agreements, stadium naming rights, LTSA commitments and other contractual obligations.

	By Remaining Maturity at December 31, 2013					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2012 Total
	(In millions)					
Letters of credit and surety bonds	$1,654	$47	$—	$—	$1,701	$1,594
Asset sales guarantee obligations	—	—	275	—	275	275
Commercial sales arrangements	81	112	23	1,338	1,554	1,579
Other guarantees	78	4	—	469	551	356
Total guarantees	$1,813	$163	$298	$1,807	$4,081	$3,804

Fair Value of Derivative Instruments

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

NRG's trading activities are subject to limits in accordance with the Company's Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

The tables below disclose the activities that include both exchange and non-exchange traded contracts accounted for at fair value in accordance with ASC 820, Fair Value Measurements and Disclosures, or ASC 820. Specifically, these tables disaggregate realized and unrealized changes in fair value; disaggregate estimated fair values at December 31, 2013, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2013. For a full discussion of the Company's valuation methodology of its contracts, see Derivative Fair Value Measurements in Item 15 — Note 4, Fair Value of Financial Instruments, to the Consolidated Financial Statements.

Derivative Activity Gains/(Losses)	(In millions)
Fair value of contracts as of December 31, 2012	$825
Contracts realized or otherwise settled during the period	(550)
Changes in fair value	114
Fair value of contracts as of December 31, 2013	$389

	Fair Value of Contracts as of December 31, 2013				
	Maturity				
Fair value hierarchy Gains/(Losses)	1 Year or Less	Greater Than 1 Year to 3 Years	Greater Than 3 Years to 5 Years	Greater Than 5 Years	Total Fair Value
	(In millions)				
Level 1	$53	$68	$9	$—	$130
Level 2	208	2	(2)	38	246
Level 3	12	1	—	—	13
Total	$273	$71	$7	$38	$389

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company's derivative assets or liabilities are recorded on a separate line item on the balance sheet. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company's portfolio. As discussed in Item 7A — Quantitative and Qualitative Disclosures About Market Risk, Commodity Price Risk, NRG measures the sensitivity of the Company's portfolio to potential changes in market prices using VaR a statistical model which attempts to predict risk of loss based on market price and volatility. NRG's risk management policy places a limit on one-day holding period VaR, which limits the Company's net open position. As the Company's trade-by-trade derivative accounting results in a gross-up of the Company's derivative assets and liabilities, the net derivative assets and liability position is a better indicator of NRG's hedging activity. As of December 31, 2013, NRG's net derivative asset was $389 million, a decrease to total fair value of $436 million as compared to December 31, 2012. This decrease was primarily driven by the roll off of contracts that settled during the period, partially offset by an increase in fair value of existing contracts due to the decreases in gas and power prices.

Based on a sensitivity analysis using simplified assumptions, the impact of a $0.50 per MMBtu increase in natural gas prices across the term of the derivative contracts would result in a decrease of approximately $279 million in the net value of derivatives as of December 31, 2013.

The impact of a $0.50 per MMBtu decrease in natural gas prices across the term of the derivative contracts would result in an increase of approximately $251 million in the net value of derivatives as of December 31, 2013.

Critical Accounting Policies and Estimates

NRG's discussion and analysis of the financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these financial statements and related disclosures in compliance with U.S. GAAP requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and the fair value of certain assets and liabilities. These judgments, in and of themselves, could materially affect the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may also have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, NRG evaluates these estimates, utilizing historic experience, consultation with experts and other methods the Company considers reasonable. In any event, actual results may differ substantially from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the information that gives rise to the revision becomes known.

NRG's significant accounting policies are summarized in Item 15 — Note 2, Summary of Significant Accounting Policies, to the Consolidated Financial Statements. The Company identifies its most critical accounting policies as those that are the most pervasive and important to the portrayal of the Company's financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain.

Accounting Policy	Judgments/Uncertainties Affecting Application
Derivative Instruments	Assumptions used in valuation techniques Assumptions used in forecasting generation Market maturity and economic conditions Contract interpretation Market conditions in the energy industry, especially the effects of price volatility on contractual commitments
Income Taxes and Valuation Allowance for Deferred Tax Assets	Ability to be sustained upon audit examination of taxing authorities Interpret existing tax statute and regulations upon application to transactions Ability to utilize tax benefits through carry backs to prior periods and carry forwards to future periods
Impairment of Long Lived Assets	Recoverability of investment through future operations Regulatory and political environments and requirements Estimated useful lives of assets Environmental obligations and operational limitations Estimates of future cash flows Estimates of fair value Judgment about triggering events
Goodwill and Other Intangible Assets	Estimated useful lives for finite-lived intangible assets Judgment about impairment triggering events Estimates of reporting unit's fair value Fair value estimate of intangible assets acquired in business combinations

Contingencies	Estimated financial impact of event(s) Judgment about likelihood of event(s) occurring Regulatory and political environments and requirements

Derivative Instruments

The Company follows the guidance of ASC 815 to account for derivative instruments. ASC 815 requires the Company to mark-to-market all derivative instruments on the balance sheet, and recognize changes in the fair value of non-hedge derivative instruments immediately in earnings. In certain cases, NRG may apply hedge accounting to the Company's derivative instruments. The criteria used to determine if hedge accounting treatment is appropriate are: (i) the designation of the hedge to an underlying exposure; (ii) whether the overall risk is being reduced; and (iii) if there is a correlation between the changes in fair value of the derivative instrument and the underlying hedged item. Changes in the fair value of derivatives instruments accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged item, or deferred and recorded as a component of OCI and subsequently recognized in earnings when the hedged transactions occur.

For purposes of measuring the fair value of derivative instruments, NRG uses quoted exchange prices and broker quotes. When external prices are not available, NRG uses internal models to determine the fair value. These internal models include assumptions of the future prices of energy commodities based on the specific market in which the energy commodity is being purchased or sold, using externally available forward market pricing curves for all periods possible under the pricing model. In order to qualify derivative instruments for hedged transactions, NRG estimates the forecasted generation and forecasted borrowings for interest rate swaps occurring within a specified time period. Judgments related to the probability of forecasted generation occurring are based on available baseload capacity, internal forecasts of sales and generation, and historical physical delivery on similar contracts. Judgments related to the probability of forecasted borrowings are based on the estimated timing of project construction, which can vary based on various factors. The probability that hedged forecasted generation and forecasted borrowings will occur by the end of a specified time period could change the results of operations by requiring amounts currently classified in OCI to be reclassified into earnings, creating increased variability in the Company's earnings. These estimations are considered to be critical accounting estimates.

Certain derivative instruments that meet the criteria for derivative accounting treatment also qualify for a scope exception to derivative accounting, as they are considered to be NPNS. The availability of this exception is based upon the assumption that NRG has the ability and it is probable to deliver or take delivery of the underlying item. These assumptions are based on available baseload capacity, internal forecasts of sales and generation and historical physical delivery on contracts. Derivatives that are considered to be NPNS are exempt from derivative accounting treatment, and are accounted for under accrual accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception due to changes in estimates, the related contract would be recorded on the balance sheet at fair value combined with the immediate recognition through earnings.

Income Taxes and Valuation Allowance for Deferred Tax Assets

As of December 31, 2013, NRG had a valuation allowance of $291 million. This amount is comprised of foreign net operating loss carryforwards of $74 million, foreign capital loss carryforwards of approximately $1 million and U.S. domestic state NOLs of $216 million. The Company believes it is more likely than not that the results of future operations will generate sufficient taxable income which includes the future reversal of existing taxable temporary differences to realize deferred tax assets, net of valuation allowances. In arriving at this conclusion to utilize projections of future profit before tax in our estimate of future taxable income, the Company considered the profit before tax generated in recent years.

NRG continues to be under audit for multiple years by taxing authorities in other jurisdictions. Considerable judgment is required to determine the tax treatment of a particular item that involves interpretations of complex tax laws. NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including operations located in Australia.

Prior to the GenOn acquisition in December 2012, the Company was not subject to U.S. federal income tax examinations for years prior to 2007. GenOn is no longer subject to U.S. federal income tax examinations for years prior to 2010. With few exceptions, state and local income tax examinations are no longer open for years before 2007. The Company's significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2008.

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Evaluation of Assets for Impairment and Other Than Temporary Decline in Value
In accordance with ASC 360, Property, Plant, and Equipment, or ASC 360, NRG evaluates property, plant and equipment and certain intangible assets for impairment whenever indicators of impairment exist. Examples of such indicators or events are:

- Significant decrease in the market price of a long-lived asset;
- Significant adverse change in the manner an asset is being used or its physical condition;
- Adverse business climate;
- Accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset;
- Current-period loss combined with a history of losses or the projection of future losses; and
- Change in the Company's intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset, through considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available to the Company. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. NRG uses its best estimates in making these evaluations and considers various factors, including forward price curves for energy, fuel costs and operating costs. However, actual future market prices and project costs could vary from the assumptions used in the Company's estimates, and the impact of such variations could be material.
For assets to be held and used, if the Company determines that the undiscounted cash flows from the asset are less than the carrying amount of the asset, NRG must estimate fair value to determine the amount of any impairment loss. Assets held-for-sale are reported at the lower of the carrying amount or fair value less the cost to sell. The estimation of fair value under ASC 360, whether in conjunction with an asset to be held and used or with an asset held-for-sale, and the evaluation of asset impairment are, by their nature, subjective. NRG considers quoted market prices in active markets to the extent they are available. In the absence of such information, the Company may consider prices of similar assets, consult with brokers, or employ other valuation techniques. NRG will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as previously discussed with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in the Company's estimates, and the impact of such variations could be material.
Annually during the fourth quarter, the Company revises its views of power and fuel prices including the Company's fundamental view for long term prices in connection with the preparation of its annual budget. Changes to the Company’s views of long term power and fuel prices impacted the Company’s projections of profitability, based on management's estimate of supply and demand within the sub-markets for each plant and the physical and economic characteristics of each plant. The Company's revised views of projected profitability for Indian River resulted in a significant adverse change in the extent to which the assets are expected to be used. As a result, the Company considered this to be an indicator of impairment and performed an impairment test for these assets under ASC 360, Property, Plant and Equipment. The carrying amount of the assets was lower than the future net cash flows expected to be generated by the asset, considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. As a result, the assets are considered to be impaired, and the Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. The fair value of the assets was determined by factoring in the probability weighting of different courses of action available to the Company and included both an income approach and a market approach. The Company recorded an impairment loss related to Indian River in the fourth quarter of 2013 of $459 million, as described in Note

10, Asset Impairments.

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

During the fourth quarter, the Company reviewed its 37.5% interest in Gladstone for impairment utilizing the other-than-temporary impairment model under ASC 820, Fair Value Measurements, due to future market expectations as well as discussions with the managing joint venture participants regarding the plant's expected life. In determining fair value, the Company considered project specific assumptions for future project operating revenues and costs and expected plant operations. The carrying amount of the Company's equity method investment exceeded the fair value of the investment and the Company concluded that the decline is considered to be other than temporary. As a result, the Company measured the impairment loss as the difference between the carrying amount and fair value of the investment and recorded an impairment loss in the fourth quarter of 2013 of $92 million, as described in Note 10, Asset Impairments.

Goodwill and Other Intangible Assets

At December 31, 2013, NRG reported goodwill of $2.0 billion, consisting of $1.7 billion in its Texas operating segment, or NRG Texas, that is associated with the acquisition of Texas Genco in 2006, and $272 million primarily in its retail operating segment that is associated with other business acquisitions. The Company has also recorded intangible assets in connection with its business acquisitions, measured primarily based on significant inputs that are not observable in the market and thus represent a Level 3 measurement as defined in ASC 820. See Item 15 — Note 3, Business Acquisitions and Dispositions, and Note 11, Goodwill and Other Intangibles, to the Consolidated Financial Statements for further discussion.

The Company applies ASC 805, Business Combinations, or ASC 805, and ASC 350, to account for its goodwill and intangible assets. Under these standards, the Company amortizes all finite-lived intangible assets over their respective estimated weighted-average useful lives, while goodwill has an indefinite life and is not amortized. However, goodwill and all intangible assets not subject to amortization are tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Company tests goodwill for impairment at the reporting unit level, which is identified by assessing whether the components of the Company's operating segments constitute businesses for which discrete financial information is available and whether segment management regularly reviews the operating results of those components. The Company performs the annual goodwill impairment assessment as of December 31 or when events or changes in circumstances indicate that the carrying value may not be recoverable. In 2011, NRG adopted the provisions of ASU 2011-08, Intangibles - Goodwill and Other (Topic 350) Testing Goodwill for Impairment, or ASU 2011-08, which allows the consideration of qualitative factors to determine if it is more likely than not that impairment has occurred. In the absence of sufficient qualitative factors, goodwill impairment is determined utilizing a two-step process. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary, the Company's goodwill and/or intangible asset with indefinite lives will be impaired at that time.

The Company performed step one of the two-step impairment test for its Retail Business reporting units, Green Mountain and Energy Plus, which is at the operating segment level. The Company determined the fair value of these reporting units using primarily an income approach. Under the income approach, the Company estimated the fair value of Green Mountain and Energy Plus to exceed its carrying value by approximately 68% and 24%, respectively, at December 31, 2013. As such, the Company concluded that goodwill associated with the Retail Business reporting units is not impaired as of December 31, 2013.

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The Company performed step one of the two-step impairment test for its Texas reporting unit, NRG Texas, which is at the operating segment level. The Company determined the fair value of this reporting unit using primarily an income approach and then applied an overall market approach reasonableness test to reconcile that fair value with NRG's overall market capitalization. The Company believes the methodology and assumptions used in the valuation are consistent with the views of market participants. Significant inputs to the determination of fair value were as follows:

- The Company applied a discounted cash flow methodology to the long-term budgets for all of the plants in the region. This approach is consistent with that used to determine fair value associated with the Company's three solid-fuel plants and the Cedar Bayou facility in prior years. For the current year, the Company applied this methodology to all of the plants. The significant assumptions used to derive the long-term budgets used in the income approach are affected by the following key inputs:

The Company's views of power and fuel prices considers market prices for the first five year period and the Company's fundamental view for the longer term. Hedging is included to the extent of contracts already in place;

The terminal value in year 2019 is calculated using the Gordon Growth Model, which assumes that the terminal value grows at a constant rate in perpetuity;

Projected generation and resulting energy gross margin in the long-term budgets is based on an hourly dispatch that simulates dispatch of each unit into the power market. The dispatch simulation is based on power prices, fuel prices, and the physical and economic characteristics of each plant.

- The additional significant assumptions used in overall valuation of NRG Texas are as follows:

The discount rate applied to internally developed cash flow projections for the NRG Texas reporting unit represents the weighted average cost of capital consistent with the risk inherent in future cash flows and based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable companies in the integrated utility industry.

The intangible value to NRG Texas for synergies it provides to the Retail Business was determined by capitalizing estimated annual collateral charge and supply cost savings.

Under step one, if the fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, the Company estimated the fair value of NRG Texas' invested capital to exceed its carrying value by approximately 16% at December 31, 2013. The Company also evaluated various market-derived data including market research forecasts, recent merger and acquisition activity and earnings multiples, and together with its estimate of fair value, concluded that NRG Texas's goodwill is not impaired at December 31, 2013.

To reconcile the fair value determined under the income approach with NRG's market capitalization, the Company considered historical and future budgeted earnings measures to estimate the average percentage of total company value represented by NRG Texas, and applied this percentage to an adjusted business enterprise value of NRG. To derive this adjusted business enterprise value, the Company applied a range of control premiums based on recent market transactions to the business enterprise value of NRG on a non-controlling, marketable basis, and also made adjustments for some non-operating assets. The Company was able to reconcile the proportional value of NRG Texas to NRG's market capitalization at a value that would not indicate an impairment.

The Company's estimate of fair value under the income approach described above is affected by assumptions about projected power prices, generation, fuel costs, capital expenditure requirements and environmental regulations, and the Company believes that the most significant impact arises from future power prices. The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants. Due to downward trends in natural gas prices, the Company performed a sensitivity scenario by using a hypothetical $0.50 per MMBtu drop in the natural gas market price for the first five year period and a $0.50 per MMBtu drop in the Company's longer-term fundamental view as used in the Company's long-term budgets and the resulting impact to the implied heat rate that would support new build of combined cycle gas plant in the Texas markets, coal and transportation charges, contracted hedges, and the impact on forecasted generation for the baseload plants during the budget period. Under this sensitivity scenario, the fair value of NRG Texas was 5% above its carrying value as of December 31, 2013. While not required, the Company further performed a high-level hypothetical step two analysis for this sensitivity scenario. Step two requires an allocation of fair value to the individual asset and liabilities using a hypothetical purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded. Under the hypothetical step two for the sensitivity scenario it was determined that no goodwill impairment was necessary as of December 31, 2013.

Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of the annual goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of the NRG Texas reporting unit may include such items as follows:

- Falling or depressed long-term natural gas prices which may result in lower power prices in the markets in which the Texas reporting unit operates;
- A significant change to power plants' new-build/retirement economics and reserve margins resulting primarily from unexpected environmental or regulatory changes; and/or
- Macroeconomic factors that significantly differ from the Company's assumptions in timing or degree.

If long-term natural gas prices for periods beyond 2014 remain depressed for an extended period, the Company's goodwill may become impaired in the future, which would result in a non-cash charge, not to exceed $1.7 billion, related to the NRG Texas reporting unit.

Contingencies

NRG records a loss contingency when management determines it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Gain contingencies are not recorded until management determines it is certain that the future event will become or does become a reality. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events, and estimates of the financial impacts of such events. NRG describes in detail its contingencies in Item 15 — Note 22, Commitments and Contingencies, to the Consolidated Financial Statements.

Recent Accounting Developments

See Item 15 — Note 2, Summary of Significant Accounting Policies, to the Consolidated Financial Statements for a discussion of recent accounting developments.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

NRG is exposed to several market risks in the Company's normal business activities. Market risk is the potential loss that may result from market changes associated with the Company's merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks the Company is exposed to are commodity price risk, interest rate risk, liquidity risk, credit risk and currency exchange risk. In order to manage these risks the Company uses various fixed-price forward purchase and sales contracts, futures and option contracts traded on NYMEX, and swaps and options traded in the over-the-counter financial markets to:

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

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities, and correlations between various commodities, such as natural gas, electricity, coal, oil, and emissions credits. NRG manages the commodity price risk of the Company's merchant generation operations and load serving obligations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales and purchases of electricity and fuel. These instruments include forwards, futures, swaps, and option contracts traded on various exchanges, such as NYMEX and Intercontinental Exchange, or ICE, as well as over-the-counter markets. The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operation and other factors.

While some of the contracts the Company uses to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. NRG uses the Company's best estimates to determine the fair value of those derivative contracts. However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuation, and such variations could be material.

NRG measures the risk of the Company's portfolio using several analytical methods, including sensitivity tests, scenario tests, stress tests, position reports, and VaR. NRG uses a Monte Carlo simulation based VaR model to estimate the potential loss in the fair value of the Company's energy assets and liabilities, which includes generation assets, load obligations, and bilateral physical and financial transactions. The key assumptions for the Company's VaR model include: (i) lognormal distribution of prices; (ii) one-day holding period; (iii) 95% confidence interval; (iv) rolling 36-month forward looking period; and (v) market implied volatilities and historical price correlations.

As of December 31, 2013, the VaR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the VaR model, was $76 million.

The following table summarizes average, maximum and minimum VaR for NRG for the years ended December 31, 2013, and 2012:

(In millions)	2013	2012
VaR as of December 31,	$76	$92
For the year ended December 31,		
Average	$88	$66
Maximum	104	96
Minimum	72	24

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

In order to provide additional information, the Company also uses VaR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VaR for the derivative financial instruments calculated using the diversified VaR model as of December 31, 2013, for the entire term of these instruments entered into for both asset management and trading, was $32 million, primarily driven by asset-backed transactions.

Interest Rate Risk

NRG is exposed to fluctuations in interest rates through the Company's issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. NRG's risk management policies allow the Company to reduce interest rate exposure from variable rate debt obligations.

NRG entered into interest rate swaps, which became effective on April 1, 2011, and were intended to hedge the risks associated with floating interest rates. For the interest rate swaps, the Company paid its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG received the monthly equivalent of a floating interest payment based on a 1-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties were made monthly and the LIBOR was determined in advance of each interest period. The total notional amount of the swaps, which matured on February 1, 2013, was $900 million.

In addition to those discussed above, the Company's project subsidiaries enter into interest rate swaps, intended to hedge the risks associated with interest rates on non-recourse project level debt. See Item 15 - Note 12, Debt and Capital Leases, to the Consolidated Financial Statements, for more information about interest rate swaps of the Company's project subsidiaries.

If all of the above swaps had been discontinued on December 31, 2013, the Company would have owed the counterparties $51 million. Based on the investment grade rating of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

As part of the CVSR financing, the Company entered into swaptions with a notional value of $686 million in order to hedge the project interest rate risk. All of the swaptions expired prior to December 31, 2013.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of December 31, 2013, a 1% change in interest rates would result in a $22 million change in interest expense on a rolling twelve month basis.

As of December 31, 2013, the Company's debt fair value was $17.2 billion and the carrying value was $16.8 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company's long-term debt by $1.3 billion.

Liquidity Risk

Liquidity risk arises from the general funding needs of the Company's activities and in the management of the Company's assets and liabilities. The Company is currently exposed to additional collateral posting if natural gas prices decline primarily due to the long natural gas equivalent position at various exchanges used to hedge NRG's retail supply load obligations.

Based on a sensitivity analysis for power and gas positions under marginable contracts, a $0.50 per MMBtu change in natural gas prices across the term of the marginable contracts would cause a change in margin collateral posted of approximately $51 million as of December 31, 2013 and a 1.00 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $65 million as of December 31, 2013. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2013.

Counterparty Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties' credit limits; (iii) the use of credit mitigation measures such as margin, collateral, prepayment arrangements, or volumetric limits; (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty risk by having a diversified portfolio of counterparties. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at the Company to cover the credit risk of the counterparty until positions settle.

As of December 31, 2013, aggregate counterparty credit exposure to a significant portion of the Company's counterparties totaled $813 million, of which the Company held collateral (cash and letters of credit) against those positions of $5 million resulting in a net exposure of $808 million. Approximately 87% of the Company's exposure before collateral is expected to roll off by the end of 2015. The following table highlights the Company's portfolio credit quality and aggregated net counterparty credit exposure by industry sector. Net counterparty credit exposure is defined as the aggregate net asset position with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and NPNS, and non-derivative transactions. As of December 31, 2013, the aggregate credit exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure [(a)] (% of Total)	
Financial institutions	52	%
Utilities, energy merchants, marketers and other	29	
Coal and emissions	1	
ISOs	18	
Total	100	%

Category	Net Exposure [(a)] (% of Total)	
Investment grade	94	%
Non-Rated	6	
Total	100	%

(a) Counterparty credit exposure excludes coal transportation contracts because of the unavailability of market prices.

The Company has credit exposure to certain wholesale counterparties representing more than 10% of the total net exposure discussed above and the aggregate credit exposure to such counterparties was $349 million. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, the Company does not anticipate a material impact on its financial position or results of operations from nonperformance by any counterparty.

Counterparty credit exposure described above excludes credit risk exposure under certain long term contracts, including California tolling agreements, South Central load obligations, solar PPAs and a coal supply agreement. As external sources or observable market quotes are not available to estimate such exposure, the Company valued these contracts based on various techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Based on these valuation techniques, as of December 31, 2013, credit exposure to these counterparties was approximately $2.3 billion, including $797 million related to assets of NRG Yield, Inc., for the next five years. This amount excludes potential credit exposures for projects with long term PPAs that have not reached commercial operations. The majority of these power contracts are with utilities or public power entities with strong credit quality and public utility commission or other regulatory support. However, such regulated utility counterparties can be impacted by changes in government regulations, which NRG is unable to predict. In the case of the coal supply agreement, NRG holds a lien against the underlying asset which significantly reduces the risk of loss.

Retail Customer Credit Risk

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

As of December 31, 2013, the Company's retail customer credit exposure to C&I customers was diversified across many customers and various industries, as well as government entities.

NRG is also exposed to credit risk relating to its Mass customers, which may result in a write-off of bad debt. The Company's bad debt expense was $67 million and $45 million for the years ending December 31, 2013 and 2012, respectively. Current economic conditions may affect the Company's customers' ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Credit Risk Related Contingent Features

Certain of the Company's hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed "adequate assurance" under the agreements, or require the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2013, was $85 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2013, was $15 million. The Company is also a party to certain marginable agreements under which it has a net liability position but the counterparty has not called for the collateral due, which is approximately $34 million as of December 31, 2013.

Currency Exchange Risk

NRG's foreign earnings and investments may be subject to foreign currency exchange risk, which NRG generally does not hedge. As these earnings and investments are not material to NRG's consolidated results, the Company's foreign currency exposure is limited.

Item 8 — Financial Statements and Supplementary Data

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K.

Item 9 — Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A - Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures and Internal Control Over Financial Reporting

Under the supervision and with the participation of NRG's management, including its principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures, as such term is defined in Rules 13a-15(e) or 15d-15(e) of the Exchange Act. Based on this evaluation, the Company's principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this annual report on Form 10-K. Management's report on the Company's internal control over financial reporting and the report of the Company's independent registered public accounting firm are incorporated under the caption "Management's Report on Internal Control over Financial Reporting" and under the caption "Report of Independent Registered Public Accounting Firm" in this Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Changes in Internal Control over Financial Reporting

There were no changes in NRG’s internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred in the fourth quarter of 2013 that materially affected, or are reasonably likely to materially affect, NRG’s internal control over financial reporting.

Inherent Limitations over Internal Controls

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

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

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

Item 9B — Other Information

None.

PART III
Item 10 — Directors, Executive Officers and Corporate Governance
Directors
E. Spencer Abraham has been a director of NRG since December 2012. Previously, he served as a director of GenOn Energy, Inc. from January 2012 to December 2012. He is Chairman and Chief Executive Officer of The Abraham Group, an international strategic consulting firm based in Washington, D.C which he founded in 2005. Prior to that, Secretary Abraham served as Secretary of Energy under President George W. Bush from 2001 through January 2005 and was a U.S. Senator for the State of Michigan from 1995 to 2001. Secretary Abraham serves on the board of Occidental Petroleum Corporation, PBF Energy, and the following private companies: C3 Energy Resource Management, International Battery and Sindicatum Sustainable Resources. Secretary Abraham also serves as chairman of the advisory committee of Lynx Global Realty Asset Fund and Uranium Energy Corporation. Secretary Abraham previously served as the non-executive chairman of AREVA, Inc., the U.S. subsidiary of the French-owned nuclear company, and as a director of Deepwater Wind LLC, International Battery, Green Rock Energy, ICx Technologies and PetroTiger. He also previously served on the advisory board or committees of Midas Medici (Utilipoint), Millennium Private Equity, Sunovia and Wetherly Capital.
Kirbyjon H. Caldwell has been a director of NRG since March 2009. He was a director of Reliant Energy, Inc. from August 2003 to March 2009. Since 1982, he has served as Senior Pastor at the 16,000-member Windsor Village United Methodist Church in Houston, Texas. Pastor Caldwell was also a director of United Continental Holdings, Inc. (formerly Continental Airlines, Inc.) from 1999 to September 2011.
Lawrence S. Coben has been a director of NRG since December 2003. He is currently Chairman and Chief Executive Officer of Tremisis Energy Corporation LLC. Dr. Coben was Chairman and Chief Executive Officer of Tremisis Energy Acquisition Corporation II, a publicly held company, from July 2007 through March 2009 and of Tremisis Energy Acquisition Corporation from February 2004 to May 2006. From January 2001 to January 2004, he was a Senior Principal of Sunrise Capital Partners L.P., a private equity firm. From 1997 to January 2001, Dr. Coben was an independent consultant. From 1994 to 1996, Dr. Coben was Chief Executive Officer of Bolivian Power Company. Dr. Coben is also Executive Director of the Sustainable Preservation Initiative and a Consulting Scholar at the University of Pennsylvania Museum of Archaeology and Anthropology.
Howard E. Cosgrove has served as Chairman of the Board and a director of NRG since December 2003. He was Chairman and Chief Executive Officer of Conectiv and its predecessor Delmarva Power and Light Company from December 1992 to August 2002. Prior to December 1992, Mr. Cosgrove held various positions with Delmarva Power and Light including Chief Operating Officer and Chief Financial Officer. Mr. Cosgrove serves on the Board of Trustees of the University of Delaware and the Hagley Museum and Library.
David Crane has served as the President, Chief Executive Officer and a director of NRG since December 2003. Mr. Crane also serves as the President, Chief Executive Officer and a director of NRG Yield, Inc. since December 2012, and was appointed Chairman of the Board of Directors of NRG Yield, Inc. in connection with its initial public offering in July 2013. Prior to joining NRG, Mr. Crane served as Chief Executive Officer of International Power plc, a UK-domiciled wholesale power generation company, from January 2003 to November 2003, and as Chief Operating Officer from March 2000 through December 2002. Mr. Crane was Senior Vice President - Global Power New York at Lehman Brothers Inc., an investment banking firm, from January 1999 to February 2000, and was Senior Vice President - Global Power Group, Asia (Hong Kong) at Lehman Brothers from June 1996 to January 1999. Mr. Crane was also a director of El Paso Corporation from December 2009 to May 2012.
Terry G. Dallas has been a director of NRG since December 2012. Previously, he served as a director of GenOn Energy, Inc. from December 2010 to December 2012. Mr. Dallas served as a director of Mirant Corporation from 2006 until December 2010. Mr. Dallas was also the former Executive Vice President and Chief Financial Officer of Unocal Corporation, an oil and gas exploration and production company prior to its merger with Chevron Corporation, from 2000 to 2005. Prior to that, Mr. Dallas held various executive finance positions in his 21-year career with Atlantic Richfield Corporation, an oil and gas company with major operations in the United States, Latin America, Asia, Europe and the Middle East.

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William E. Hantke has been a director of NRG since March 2006. Mr. Hantke served as Executive Vice President and Chief Financial Officer of Premcor, Inc., a refining company, from February 2002 until December 2005. Mr. Hantke was Corporate Vice President of Development of Tosco Corporation, a refining and marketing company, from September 1999 until September 2001, and he also served as Corporate Controller from December 1993 until September 1999. Prior to that position, he was employed by Coopers & Lybrand as Senior Manager, Mergers and Acquisitions from 1989 until 1990. He also held various positions from 1975 until 1988 with AMAX, Inc., including Corporate Vice President, Operations Analysis and Senior Vice President, Finance and Administration, Metals and Mining. He was employed by Arthur Young from 1970 to 1975 as Staff/Senior Accountant. Mr. Hantke was Non-Executive Chairman of Process Energy Solutions, a private alternative energy company until March 31, 2008 and served as director and Vice-Chairman of NTR Acquisition Co., an oil refining start-up, until January 2009.
Paul W. Hobby has been a director of NRG since March 2006. Mr. Hobby is the Managing Partner of Genesis Park, L.P., a Houston-based private equity business specializing in technology and communications investments which he helped to form in 2000. In that capacity, he serves as the Chief Executive Officer of Alpheus Communications, Inc., a Texas wholesale telecommunications provider, and as Former Chairman of CapRock Services Corp., the largest provider of satellite services to the global energy business. From November 1992 until January 2001, he served as Chairman and Chief Executive Officer of Hobby Media Services and was Chairman of Columbine JDS Systems, Inc. from 1995 until 1997. He was an Assistant U.S. Attorney for the Southern District of Texas from 1989 to 1992, Chief of Staff to the Lieutenant Governor of Texas, Bob Bullock, in 1991 and an Associate at Fulbright & Jaworski from 1986 to 1989. Mr. Hobby is also a director of Stewart Information Services Corporation (Stewart Title).
Gerald Luterman has been a director of NRG since April 2009. He also served as Interim Chief Financial Officer of the Company from November 2009 through May 2010. Mr. Luterman was Executive Vice President and Chief Financial Officer of KeySpan Corporation from August 1999 to September 2007. Prior to this time, Mr. Luterman had more than 30 years experience in senior financial positions with companies including American Express, Booz Allen & Hamilton, Emerson Electric Company and Arrow Electronics. Mr. Luterman serves as a director of Harbinger Group Inc. since April 2013. Mr. Luterman also served as a director of IKON Office Solutions, Inc. from November 2003 until August 2008 and U.S. Shipping Partners L.P. from May 2006 until November 2009.
Edward R. Muller has served as Vice Chairman of the Board and a director of NRG since December 2012. Previously, he served as the Chairman and Chief Executive Officer of GenOn Energy, Inc from December 2010 to December 2012. He also served as President of GenOn from August 2011to December 2012. Prior to that, Mr. Muller served as the Chairman, President and Chief Executive Officer of Mirant Corporation from 2005 to December 2010. He served as President and Chief Executive Officer of Edison Mission Energy, a California-based independent power producer from 1993 to 2000. Mr. Muller is also a director of Transocean Ltd. and AeroVironment, Inc.
Anne C. Schaumburg has been a director of NRG since April 2005. From 1984 until her retirement in 2002, she was Managing Director of Credit Suisse First Boston and a Senior Banker in the Global Energy Group. From 1979 to 1984, she was in the Utilities Group at Dean Witter Financial Services Group, where she last served as Managing Director. From 1971 to 1978, she was at The First Boston Corporation in the Public Utilities Group. Ms. Schaumburg is also a director of Brookfield Infrastructure Partners L.P.
Evan J. Silverstein has been a director of NRG since December 2012. Previously, he served as a director of GenOn Energy, Inc. from August 2006 to December 2012. He served as General Partner and Portfolio Manager of SILCAP LLC, a market-neutral hedge fund that principally invests in utilities and energy companies, from January 1993 until his retirement in December 2005. Previously, he served as portfolio manager specializing in utilities and energy companies and as senior equity utility analyst. Mr. Silverstein has given numerous speeches and has testified before Congress on a variety of energy-related issues. He is an audit committee financial expert.
Thomas H. Weidemeyer has been a director of NRG since December 2003. Until his retirement in December 2003, Mr. Weidemeyer served as Director, Senior Vice President and Chief Operating Officer of United Parcel Service, Inc., the world's largest transportation company and President of UPS Airlines. Mr. Weidemeyer became Manager of the Americas International Operation in 1989, and in that capacity directed the development of the UPS delivery network throughout Central and South America. In 1990, Mr. Weidemeyer became Vice President and Airline Manager of UPS Airlines and, in 1994, was elected its President and Chief Operating Officer. Mr. Weidemeyer became Senior

Vice President and a member of the Management Committee of United Parcel Service, Inc. that same year, and he became Chief Operating Officer of United Parcel Service, Inc. in January 2001. Mr. Weidemeyer also serves as a director of The Goodyear Tire & Rubber Co., Waste Management, Inc. and Amsted Industries Incorporated.

Walter R. Young has been a director of NRG since December 2003. From May 1990 to June 2003, Mr. Young was Chairman, Chief Executive Officer and President of Champion Enterprises, Inc., an assembler and manufacturer of manufactured homes. Mr. Young has held senior management positions with The Henley Group, The Budd Company and BFGoodrich.

Executive Officers

David Crane has served as the President, Chief Executive Officer and a director of NRG since December 2003. For additional biographical information for Mr. Crane, see above under "Directors."

Kirkland Andrews has served as Executive Vice President and Chief Financial Officer of NRG Energy since September 2011. Mr. Andrews also has served as the Executive Vice President, Chief Financial Officer and a director of NRG Yield, Inc. since December 2012. Prior to joining NRG, he served as Managing Director and Co-Head Investment Banking, Power and Utilities - Americas at Deutsche Bank Securities from June 2009 to September 2011. Prior to this, he served in several capacities at Citigroup Global Markets Inc., including Managing Director, Group Head, North American Power from November 2007 to June 2009, and Head of Power M&A, Mergers and Acquisitions from July 2005 to November 2007. In his banking career, Mr. Andrews led multiple large and innovative strategic, debt, equity and commodities transactions.

Mauricio Gutierrez has served as Executive Vice President and Chief Operating Officer since July 2010. In this capacity, Mr. Gutierrez oversees NRG's Plant Operations, Commercial Operations, Environmental Compliance, as well as the Engineering, Procurement and Construction division. Mr. Gutierrez also has served as the Executive Vice President, Chief Operating Officer and a director of NRG Yield, Inc. since December 2012. He previously served as Executive Vice President, Commercial Operations of NRG, from January 2009 to July 2010 and Senior Vice President, Commercial Operations of NRG, from March 2008 to January 2009. In this capacity, he was responsible for the optimization of the Company's asset portfolio and fuel requirements. Prior to this, Mr. Gutierrez served as Vice President Commercial Operations Trading of NRG from May 2006 to March 2008. Prior to joining NRG in August 2004, Mr. Gutierrez held various positions within Dynegy, Inc., including Managing Director, Trading - Southeast and Texas, Senior Trader East Power and Asset Manager. Prior to Dynegy, Mr. Gutierrez served as senior consultant and project manager at DTP involved in various energy and infrastructure projects in Mexico.

David R. Hill has served as Executive Vice President and General Counsel since September 2012. Mr. Hill also has served as the Executive Vice President and General Counsel of NRG Yield, Inc. since December 2012. Prior to joining NRG, Mr. Hill was a partner and co-head of Sidley Austin LLP's global energy practice group. Prior to this, Mr. Hill served as General Counsel of the U.S. Department of Energy from August 2005 to January 2009 and, for the three years prior to that, as Deputy General Counsel for Energy Policy of the U.S. Department of Energy. Before his federal government service, Mr. Hill was a partner in major law firms in Washington, D.C. and Kansas City, Missouri, and handled a variety of regulatory, litigation and corporate matters. He received his law degree from Northwestern University School of Law in Chicago.

John W. Ragan has served as Executive Vice President and Regional President, Gulf Coast since July 2010. In this capacity, Mr. Ragan is responsible for managing NRG's largest regional power generation portfolio, totaling over 10,500 megawatts of power in Texas and NRG's retail electric provider, Reliant Energy. He previously served as Executive Vice President and Chief Operating Officer from February 2009 to July 2010, overseeing NRG's Plant Operations, Commercial Operations, Environmental Compliance, as well as the Engineering, Procurement and Construction division. He previously served as Executive Vice President and Regional President, Northeast from December 2006 to February 2009. Prior to joining NRG, Mr. Ragan was Vice President of Trading, Transmission, and Operations at FPL Energy in 2006 and also served as Vice President of Business Management for FPL Energy's Northeast Region from August 2005 through July 2006. Prior to this, Mr. Ragan served as General Manager - Containerboard and Packaging for Georgia Pacific Corporation from October 2004 through July 2005. He also served in increasing roles of responsibility for Mirant Corporation from 1996 through 2004, notably as Senior Vice President and Chief Executive Officer of Mirant's International Group from August 2003 to July 2004.

Ronald B. Stark has served as Vice President and Chief Accounting Officer since March 2012. In this capacity, Mr. Stark is responsible for directing NRG's financial accounting and reporting activities. Mr. Stark also has served as the Vice President and Chief Accounting Officer of NRG Yield, Inc. since December 2012. Prior to March 2012, Mr.

Stark served as the Company's Vice President, Internal Audit from August 2011 to February 2012. He previously served as Director, Financial Reporting of NRG from October 2007 through July 2011. Mr. Stark joined the Company in January 2007. Mr. Stark previously held various executive and managerial accounting positions at Pegasus Communications and Berlitz International and began his career with Deloitte and Touche.

Denise M. Wilson has served as Executive Vice President and President, Alternative Energy Services since July 2011. In this capacity, Ms. Wilson is responsible for the oversight of all alternative energy ventures and development. Prior to this, Ms. Wilson served as Executive Vice President and Chief Administrative Officer (“CAO”) from September 2008 to July 2011. As CAO, Ms. Wilson had oversight for several key corporate functions including Human Resources, Investor Relations, Communications and Information Technology. Ms. Wilson originally joined NRG in 2000 and served as Vice President, Human Resources from 2004 until she was named CAO in July 2006. She served in that position until March 2007 when she joined Nash-Finch Company, a leading national food distributor as Senior Vice President, Human Resources. Ms. Wilson left Nash-Finch in June 2008 to retire and then rejoined NRG in September 2008. Ms. Wilson has also served as Vice President, Human Resources Operations with Metris Companies Inc. and Director, Human Resources with General Electric ITS.

Code of Ethics

NRG has adopted a code of ethics entitled "NRG Code of Conduct" that applies to directors, officers and employees, including the chief executive officer and senior financial officers of NRG. It may be accessed through the Corporate Governance section of the Company's website at http://www.nrgenergy.com/investor/corpgov.htm. NRG also elects to disclose the information required by Form 8-K, Item 5.05, "Amendments to the Registrant's Code of Ethics, or Waiver of a Provision of the Code of Ethics," through the Company's website, and such information will remain available on this website for at least a 12-month period. A copy of the "NRG Energy, Inc. Code of Conduct" is available in print to any stockholder who requests it.

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's definitive Proxy Statement for its 2014 Annual Meeting of Stockholders.

Item 11 — Executive Compensation

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2014 Annual Meeting of Stockholders.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters
Securities Authorized for Issuance under Equity Compensation Plans

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights		(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))	
Equity compensation plans approved by security holders	9,614,132	(1)	$25.68	8,126,453	
Equity compensation plans not approved by security holders	842,426	(2)	25.65	1,053,485	
Total	10,456,558		$25.68	9,179,938	(3)

(1) Consists of shares issuable under the NRG LTIP and the ESPP. The NRG LTIP became effective upon the Company's emergence from bankruptcy. On July 28, 2010, the NRG LTIP was amended to increase the number of shares available for issuance to 22,000,000. The ESPP was approved by the Company's stockholders on May 14, 2008. As of December 31, 2013, there were 888,388 shares reserved from the Company's treasury shares for the ESPP.

(2) Consists of shares issuable under the NRG GenOn LTIP. On December 14, 2012, in connection with the Merger, NRG assumed the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, and changed the name to the NRG 2010 Stock Plan for GenOn Employees, or the NRG GenOn LTIP. While the GenOn Energy, Inc. 2010 Omnibus Incentive Plan was previously approved by stockholders of RRI Energy, Inc. before it became GenOn, the plan is listed as "not approved" because the NRG GenOn LTIP was not subject to separate line item approval by NRG's stockholders when the Merger (which included the assumption of this plan) was approved. NRG intends to make subsequent grants under the NRG GenOn LTIP. As part of the Merger, NRG also assumed the GenOn Energy, Inc. 2002 Long-Term Incentive Plan, the GenOn Energy, Inc. 2002 Stock Plan, and the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. NRG has no intention of making any grants or awards of its own equity securities under these plans. The number of securities to be issued upon the exercise of outstanding awards under these plans is 1,053,719 at a weighted-average exercise price of $56.79. See Item 15 — Note 20, Stock-Based Compensation, to Consolidated Financial Statements for a discussion of the NRG GenOn LTIP.

(3) Consists of 7,238,065 shares of common stock under NRG's LTIP, 1,053,485 shares of common stock under the NRG GenOn LTIP, and 888,388 shares of treasury stock reserved for issuance under the ESPP. In the first quarter of 2014, 71,478 were issued to employees' accounts from the treasury stock reserve for the ESPP.

Both the NRG LTIP and the NRG GenOn LTIP provide for grants of stock options, stock appreciation rights, restricted stock, performance units, deferred stock units and dividend equivalent rights. NRG's directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by the Company, are eligible to receive grants under the NRG LTIP and the NRG GenOn LTIP. However, participants eligible for the NRG LTIP at the time of the Merger are not eligible to receive grants under the NRG GenOn LTIP. The purpose of the NRG LTIP and the NRG GenOn LTIP is to promote the Company's long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to the Company's success and to enable the Company to attract, retain and reward the best available persons for positions of responsibility. The Compensation Committee of the Board of Directors administers the NRG LTIP and the NRG GenOn LTIP.

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2014 Annual Meeting of Stockholders.

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

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2014 Annual Meeting of Stockholders.

Item 14 — Principal Accounting Fees and Services

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2014 Annual Meeting of Stockholders.

PART IV
Item 15 — Exhibits, Financial Statement Schedules
(a)(1) Financial Statements
The following consolidated financial statements of NRG Energy, Inc. and related notes thereto, together with the reports thereon of KPMG LLP, are included herein:
Consolidated Statements of Operations — Years ended December 31, 2013, 2012, and 2011
Consolidated Statements of Comprehensive Income/(Loss) — Years ended December 31, 2013, 2012, and 2011
Consolidated Balance Sheets — December 31, 2013 and 2012
Consolidated Statements of Cash Flows — Years ended December 31, 2013, 2012, and 2011
Consolidated Statement of Stockholders' Equity — Years ended December 31, 2013, 2012, and 2011
Notes to Consolidated Financial Statements
(a)(2) Financial Statement Schedule
The following Consolidated Financial Statement Schedule of NRG Energy, Inc. is filed as part of Item 15(d) of this report and should be read in conjunction with the Consolidated Financial Statements.
Schedule II — Valuation and Qualifying Accounts
All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.
(a)(3) Exhibits: See Exhibit Index submitted as a separate section of this report.
(b) Exhibits
See Exhibit Index submitted as a separate section of this report.
(c) Not applicable

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NRG Energy Inc.'s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in Internal Control — Integrated Framework (1992), the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013, has been audited by KPMG LLP, the Company's independent registered public accounting firm, as stated in its report which is included in this Form 10 K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income/(loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2013. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule "Schedule II. Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), NRG Energy, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income/(loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2013. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule “Schedule II. Valuation and Qualifying Accounts.” These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc. and subsidiaries internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
February 28, 2014

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
(In millions, except per share amounts)	2013	2012	2011
Operating Revenues			
Total operating revenues	$11,295	$8,422	$9,079
Operating Costs and Expenses			
Cost of operations	8,121	6,140	6,745
Depreciation and amortization	1,256	950	896
Impairment losses	459	—	160
Selling, general and administrative	904	807	586
Acquisition-related transaction and integration costs	128	107	—
Development activity expenses	84	68	57
Total operating costs and expenses	10,952	8,072	8,444
Operating Income	343	350	635
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	7	37	35
Bargain purchase gain related to GenOn acquisition	—	296	—
Impairment losses on investments	(99)	(2)	(495)
Other income, net	13	19	19
Loss on debt extinguishment	(50)	(51)	(175)
Interest expense	(848)	(661)	(665)
Total other expense	(977)	(362)	(1,281)
Loss Before Income Taxes	(634)	(12)	(646)
Income tax benefit	(282)	(327)	(843)
Net (Loss)/Income	(352)	315	197
Less: Net income attributable to noncontrolling interest	34	20	—
Net (Loss)/Income Attributable to NRG Energy, Inc.	(386)	295	197
Dividends for preferred shares	9	9	9
(Loss)/Income Available for Common Stockholders	$(395)	$286	$188
(Loss)/Earnings Per Share Attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding — basic	323	232	240
Net (Loss)/Income per Weighted Average Common Share — Basic	$(1.22)	$1.23	$0.78
Weighted average number of common shares outstanding — diluted	323	234	241
Net (Loss)/Income per Weighted Average Common Share — Diluted	$(1.22)	$1.22	$0.78
Dividends Per Common Share	$0.45	$0.18	$—

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS)/INCOME

	For the Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Net (Loss)/Income	$(352)	$315	$197
Other Comprehensive Income/(Loss), net of tax			
Unrealized gain/(loss) on derivatives, net of income tax benefit of $6, $94, and $181	8	(163)	(309)
Foreign currency translation adjustments, net of income tax benefit of $14, $1, and $1	(24)	(1)	(2)
Reclassification adjustment for translation gain realized upon sale of Schkopau, net of income tax benefit of $0, $6, and $0	—	(11)	—
Available-for-sale securities, net of income tax expense of $2, $1, and $0	3	3	(1)
Defined benefit plan, net of income tax (expense)/benefit of $(100), $21, and $27	168	(52)	(46)
Other comprehensive income/(loss)	155	(224)	(358)
Comprehensive (Loss)/Income	(197)	91	(161)
Less: Comprehensive income attributable to noncontrolling interest	34	20	—
Comprehensive (Loss)/Income Attributable to NRG Energy, Inc.	(231)	71	(161)
Dividends for preferred shares	9	9	9
Comprehensive (Loss)/Income Available for Common Stockholders	$(240)	$62	$(170)

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2013	2012
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$2,254	$2,087
Funds deposited by counterparties	63	271
Restricted cash	268	217
Accounts receivable — trade, less allowance for doubtful accounts of $40 and $32	1,214	1,061
Inventory	898	903
Derivative instruments	1,328	2,644
Cash collateral paid in support of energy risk management activities	276	229
Deferred income taxes	258	56
Renewable energy grant receivable	539	58
Prepayments and other current assets	498	446
Total current assets	7,596	7,972
Property, Plant and Equipment		
In service	23,649	21,133
Under construction	2,775	4,428
Total property, plant and equipment	26,424	25,561
Less accumulated depreciation	(6,573)	(5,408)
Net property, plant and equipment	19,851	20,153
Other Assets		
Equity investments in affiliates	453	676
Notes receivable, less current portion	73	79
Goodwill	1,985	1,956
Intangible assets, net of accumulated amortization of $1,977 and $1,706	1,140	1,210
Nuclear decommissioning trust fund	551	473
Derivative instruments	311	662
Deferred income taxes	1,202	1,203
Other non-current assets	740	599
Total other assets	6,455	6,858
Total Assets	$33,902	$34,983

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Continued)

	As of December 31, 2013	2012
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$1,050	$147
Accounts payable	1,038	1,172
Derivative instruments	1,055	1,981
Cash collateral received in support of energy risk management activities	63	271
Accrued interest expense	185	191
Other accrued expenses	480	539
Other current liabilities	333	369
Total current liabilities	4,204	4,670
Other Liabilities		
Long-term debt and capital leases	15,767	15,736
Nuclear decommissioning reserve	294	354
Nuclear decommissioning trust liability	324	273
Postretirement and other benefit obligations	506	803
Deferred income taxes	22	55
Derivative instruments	195	500
Out-of-market contracts	1,177	1,278
Other non-current liabilities	695	796
Total non-current liabilities	18,980	19,795
Total Liabilities	23,184	24,465
3.625% convertible perpetual preferred stock; $0.01 par value; 250,000 shares issued and outstanding (at liquidation value of $250, net of issuance costs)	249	249
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 401,126,780 and 399,112,616 shares issued and 323,779,252 and 322,606,898 shares outstanding at December 31, 2013 and 2012	4	4
Additional paid-in capital	7,840	7,587
Retained earnings	3,695	4,230
Less treasury stock, at cost; 77,347,528 and 76,505,718 shares at December 31, 2013 and 2012	(1,942)	(1,920)
Accumulated other comprehensive income/(loss)	5	(150)
Noncontrolling interest	867	518
Total Stockholders' Equity	10,469	10,269
Total Liabilities and Stockholders' Equity	$33,902	$34,983

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Cash Flows from Operating Activities			
Net (loss)/income	$(352)	$315	$197
Adjustments to reconcile net (loss)/income to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	84	2	9
Bargain purchase gain related to GenOn acquisition	—	(296)	—
Depreciation and amortization	1,256	950	896
Provision for bad debts	67	45	59
Amortization of nuclear fuel	36	39	39
Amortization of financing costs and debt discount/premiums	(33)	31	32
Adjustment to loss on debt extinguishment	(15)	9	58
Amortization of intangibles and out-of-market contracts	49	146	167
Amortization of unearned equity compensation	38	41	28
(Gain)/Loss on disposals and sales of assets, net	(3)	11	14
Impairment losses	558	—	657
Changes in derivative instruments	164	124	(138)
Changes in deferred income taxes and liability for uncertain tax benefits	(67)	(353)	(859)
Changes in nuclear decommissioning trust liability	15	37	20
Cash (used)/provided by changes in other working capital, net of acquisition and disposition effects:			
Accounts receivable - trade	(224)	(131)	(119)
Inventory	11	(172)	145
Prepayments and other current assets	(22)	(26)	59
Accounts payable	275	(132)	9
Accrued expenses and other current liabilities	(114)	231	(111)
Other assets and liabilities	(453)	278	4
Net Cash Provided by Operating Activities	1,270	1,149	1,166
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(494)	(81)	(377)
Cash acquired in GenOn acquisition	—	983	—
Capital expenditures	(1,987)	(3,396)	(2,310)
Increase in restricted cash, net	(22)	(66)	(35)
(Increase)/decrease in restricted cash to support equity requirements for U.S. DOE funded projects	(26)	164	(215)
(Increase)/decrease in notes receivable	(11)	(24)	12
Proceeds from renewable energy grants	55	62	—
Purchases of emission allowances, net of proceeds	5	(1)	(19)
Investments in nuclear decommissioning trust fund securities	(514)	(436)	(406)
Proceeds from sales of nuclear decommissioning trust fund securities	488	399	385
Proceeds from sale of assets, net	13	137	7
Investments in unconsolidated affiliates	—	(25)	(66)
Other	(35)	22	(23)
Net Cash Used by Investing Activities	(2,528)	(2,262)	(3,047)

Cash Flows from Financing Activities			
Payment of dividends to preferred and common stockholders	(154)	(50)	(9)
Net receipts/(payments for) from settlement of acquired derivatives that include financing elements	267	(68)	(83)
Payment for treasury stock	(25)	—	(430)
Sales proceeds and other contributions from noncontrolling interests in subsidiaries	531	347	29
Proceeds from issuance of common stock	16	—	2
Proceeds from issuance of long-term debt	1,777	3,165	6,224
Payments for term loan for funded letter of credit facility	—	—	(1,300)
Decrease in restricted cash supporting funded letter of credit facility	—	—	1,300
Payment of debt issuance and hedging costs	(50)	(35)	(207)
Payments for short and long-term debt	(935)	(1,260)	(5,493)
Net Cash Provided by Financing Activities	1,427	2,099	33
Effect of exchange rate changes on cash and cash equivalents	(2)	(4)	2
Net Increase/(Decrease) in Cash and Cash Equivalents	167	982	(1,846)
Cash and Cash Equivalents at Beginning of Period	2,087	1,105	2,951
Cash and Cash Equivalents at End of Period	$2,254	$2,087	$1,105

See notes to Consolidated Financial Statements.

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

	Preferred Stock	Common Stock	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Noncon-trolling Interest	Total Stockholders' Equity
	(In millions)							
Balances at December 31, 2010	$—	$ 3	$ 5,323	$ 3,800	$ (1,503)	$ 432	$ 17	$ 8,072
Net income				197			—	197
Other comprehensive income						(358)		(358)
Equity-based compensation			28					28
Purchase of treasury stock					(430)			(430)
Preferred stock dividends				(9)				(9)
ESPP share purchases			(5)	(1)	9			3
NINA deconsolidation							(17)	(17)
Ivanpah contribution							183	183
Balances at December 31, 2011	$—	$ 3	$ 5,346	$ 3,987	$ (1,924)	$ 74	$ 183	$ 7,669
Net income				295			20	315
Other comprehensive loss						(224)		(224)
Issuance of shares for acquisition of GenOn		1	2,176					2,177
Equity-based compensation			34					34
Preferred stock dividends				(9)				(9)
Common stock dividends				(41)				(41)
ESPP share purchases			(1)	(2)	4			1
Sales proceeds and other contributions from noncontrolling interests			32				315	347
Balances at December 31, 2012	$—	$ 4	$ 7,587	$ 4,230	$ (1,920)	$ (150)	$ 518	$ 10,269
Net loss				(386)			34	(352)
Other comprehensive income						155		155
Equity-based compensation			36					36
Purchase of treasury stock					(25)			(25)
Preferred stock dividends				(9)				(9)
Common stock dividends				(145)				(145)
ESPP share purchases				5	3			8
NRG Yield IPO			217				240	457
Sales proceeds and other contributions from noncontrolling interests							75	75
Balances at December 31, 2013	$—	$ 4	$ 7,840	$ 3,695	$ (1,942)	$ 5	$ 867	$ 10,469

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 — Nature of Business
General
NRG Energy, Inc., or NRG or the Company, is a competitive power and energy company that aspires to be a leader in the way residential, industrial and commercial consumers think about, use, produce and deliver energy and energy services in major competitive power markets in the United States. NRG engages in the ownership and operation of power generation facilities; the trading of energy, capacity and related products; the transacting in and trading of fuel and transportation services and the direct sale of energy, services, and innovative, sustainable products to retail customers. The Company sells retail electric products and services under the name "NRG" and various brands owned by NRG. Finally, NRG aspires to be a clean energy leader and is focused on the deployment and commercialization of potentially transformative technologies, like electric vehicles, Distributed Solar and smart meter/home automation technology that collectively have the potential to fundamentally change the nature of the power industry, including a substantial change in the role of the national electric transmission grid and distribution system.
NRG's domestic generation facilities consist of intermittent, baseload, intermediate, and peaking power generation facilities. The following table summarizes NRG's global generation portfolio by operating segment, which includes 88 fossil fuel and nuclear plants, eleven Utility Scale Solar facilities and four wind farms, as well as Distributed Solar facilities. Also included is one Utility Scale Solar facility and additional Distributed Solar facilities currently under construction. All Utility Scale Solar and Distributed Solar facilities are described in megawatts on an alternating current basis. MW figures provided represent nominal summer net megawatt capacity of power generated as adjusted for the Company's owned or leased interest excluding capacity from inactive/mothballed units:

	Fossil Fuel, Nuclear, and Renewable (In MW)								
Generation Type	Texas	East	South Central	West	Alternative Energy	NRG Yield	Total Domestic	Other (Inter-national)	Total Global
Natural gas	5,917	7,651	3,817	6,779	—	843	25,007	—	25,007
Coal	4,193	6,879	1,496	—	—	—	12,568	605	13,173
Oil(a)	—	5,531	—	—	—	190	5,721	—	5,721
Nuclear	1,176	—	—	—	—	—	1,176	—	1,176
Wind	—	—	—	—	347	101	448	—	448
Utility Scale Solar	—	—	—	—	836	303	1,139	—	1,139
Distributed Solar	—	—	—	—	37	10	47	—	47
Total generation capacity	11,286	20,061	5,313	6,779	1,220	1,447	46,106	605	46,711
Capacity attributable to noncontrolling interest	—	—	—	—	(331)	(499)	(830)	—	(830)
Total net generation capacity	11,286	20,061	5,313	6,779	889	948	45,276	605	45,881
Under Construction									
Utility Scale Solar	—	—	—	—	26	—	26	—	26
Distributed Solar	—	—	—	—	6	—	6	—	6
Total under construction	—	—	—	—	32	—	32	—	32

(a) The NRG Yield operating segment consists of two dual-fuel (natural gas and oil) simple-cycle generation facilities.
In addition, the Company's thermal assets provide steam and chilled water capacity of approximately 1,374 MWt through its district energy business, 28 MWt of which is available under the right-to-use provision of the Chilled Water Service Agreement at NRG Energy Center Phoenix, AZ.
NRG sells power from its generation portfolio, offers capacity or similar products to retail electric providers and others, and provides ancillary services to support system reliability.

The Retail Business provides energy and related services to residential, commercial and institutional customers primarily located in Texas and selected Northeast markets. Products and services range from system power to home services, to bundled products which combine system power with protection products, energy efficiency and renewable energy solutions. Based on metered locations, as of December 31, 2013, NRG's Retail Business served approximately 2.3 million residential, small business, commercial and industrial customers.

NRG was incorporated as a Delaware corporation on May 29, 1992. NRG's common stock is listed on the New York Stock Exchange under the symbol "NRG". The Company's principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. NRG is dual headquartered, with financial and commercial headquarters in Princeton, New Jersey and operational headquarters in Houston, Texas. NRG's telephone number is (609) 524-4500. The address of the Company's website is www.nrgenergy.com. NRG's recent annual reports, quarterly reports, current reports, and other periodic filings are available free of charge through the Company's website.

Initial Public Offering of NRG Yield, Inc.

The Company formed NRG Yield, Inc. to own and operate a portfolio of contracted generation assets and thermal infrastructure assets that have historically been owned and/or operated by NRG and its subsidiaries. On July 22, 2013, NRG Yield, Inc. closed its initial public offering of 22,511,250 shares of Class A common stock at a price of $22 per share. Net proceeds to NRG Yield, Inc. from the sale of the Class A common stock were approximately $468 million, net of underwriting discounts and commissions of $27 million. The Company retained 42,738,250 shares of Class B common stock of NRG Yield, Inc. As a result, the Company owns a controlling interest in NRG Yield, Inc. and will consolidate this entity for financial reporting purposes. In addition, the Company retained a 65.5% interest in NRG Yield LLC. The initial public offering represented the sale of a 34.5% interest in NRG Yield LLC. NRG Yield LLC's initial assets consisted of three natural gas or dual-fired facilities, eight utility-scale solar and wind generation facilities, two portfolios of distributed solar facilities that collectively represent 1,324 net MW, and thermal infrastructure assets with an aggregate steam and chilled water capacity of 1,098 net MWt and electric generation capacity of 123 net MW. On December 31, 2013, NRG Yield LLC acquired Energy Systems, as described in Note 3, Business Acquisitions and Dispositions. The following table represents the structure of NRG Yield, Inc. after the initial public offering:

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The Company's consolidated financial statements have been prepared in accordance with U.S. GAAP. The ASC, established by the FASB, is the source of authoritative U.S. GAAP to be applied by nongovernmental entities. In addition, the rules and interpretative releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants.

The consolidated financial statements include NRG's accounts and operations and those of its subsidiaries in which the Company has a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. The usual condition for a controlling financial interest is ownership of a majority of the voting interests of an entity. However, a controlling financial interest may also exist through arrangements that do not involve controlling voting interests. As such, NRG applies the guidance of ASC 810, Consolidations, or ASC 810, to determine when an entity that is insufficiently capitalized or not controlled through its voting interests, referred to as a VIE should be consolidated.

Segment Reporting

Effective June 2013, the Company's segment structure and its allocation of corporate expenses were updated to reflect how management currently makes financial decisions and allocates resources. The Company has recast data from prior periods to reflect this change in reportable segments to conform to the current year presentation. The Company's businesses are primarily segregated based on the Retail Business, conventional power generation, alternative energy businesses, NRG Yield, and corporate activities. Within NRG's conventional power generation, there are distinct components with separate operating results and management structures for the following geographical regions: Texas, East, South Central, West and Other, which includes international businesses and maintenance services. The Company's alternative energy segment includes solar and wind assets, excluding those in the NRG Yield segment, electric vehicle services and the carbon capture business. NRG Yield includes certain of the Company's contracted generation assets including three natural gas or dual-fired facilities, eight utility-scale solar and wind generation facilities, two portfolios of distributed solar facilities and thermal infrastructure assets.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with an original maturity of three months or less at the time of purchase.

Funds Deposited by Counterparties

Funds deposited by counterparties consist of cash held by the Company as a result of collateral posting obligations from its counterparties. Some amounts are segregated into separate accounts that are not contractually restricted but, based on the Company's intention, are not available for the payment of general corporate obligations. Depending on market fluctuations and the settlement of the underlying contracts, the Company will refund this collateral to the hedge counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company's balance sheet, with an offsetting liability for this cash collateral received within current liabilities. Changes in funds deposited by counterparties are closely associated with the Company's operating activities, and are classified as an operating activity in the Company's consolidated statements of cash flows.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within the Company's projects that are restricted in their use. These funds are used to pay for current operating expenses and current debt service payments as well as to fund required equity contributions, per the restrictions of the debt agreements.

Trade Receivables and Allowance for Doubtful Accounts

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

Inventory

Inventory is valued at the lower of weighted average cost or market, and consists principally of fuel oil, coal and raw materials used to generate electricity or steam. The Company removes these inventories as they are used in the production of electricity or steam. Spare parts inventory is valued at a weighted average cost, since the Company expects to recover these costs in the ordinary course of business. The Company removes these inventories when they are used for repairs, maintenance or capital projects. Sales of inventory are classified as an operating activity in the consolidated statements of cash flows.

Property, Plant and Equipment

Property, plant and equipment are stated at cost; however impairment adjustments are recorded whenever events or changes in circumstances indicate that their carrying values may not be recoverable. NRG also classifies nuclear fuel related to the Company's 44% ownership interest in STP as part of the Company's property, plant, and equipment. Significant additions or improvements extending asset lives are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation other than nuclear fuel is computed using the straight-line method, while nuclear fuel is amortized based on units of production over the estimated useful lives. Certain assets and their related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in cost of operations in the consolidated statements of operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with ASC 360. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value with the difference recorded in operating costs and expenses in the statements of operations. Fair values are determined by a variety of valuation methods, including third-party appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with ASC 323, Investments-Equity Method and Joint Ventures, or ASC 323, which requires that a loss in value of an investment that is other than a temporary decline should be recognized. The Company identifies and measures losses in the value of equity method investments based upon a comparison of fair value to carrying value.

For further discussion of these matters, refer to Note 10, Asset Impairments.

Development Activity Expenses and Capitalized Interest

Project development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, Board of Director approval pursuant to a formal project plan that subjects the Company to significant future obligations that can only be discharged by the use of a Company asset.

Development activity expenses include project development costs, which are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including, among others, Board of Director approval pursuant to a formal project plan that subjects the Company to significant future obligations that can only be discharged by the use of a Company asset. When a project is available for operations, capitalized project development costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Development activity expenses also include selling, general, and administrative expenses associated with the current operations of certain developing businesses including residential solar, electric vehicles, waste-to-energy, carbon capture and other emerging technologies. The revenue associated with these businesses was immaterial for the years ended December 31, 2013, 2012, and 2011. When it is determined that a business will remain an ongoing part of the Company's operations or when operating revenues become material relative to the operating costs of the underlying business, the Company no longer classifies a business as a development activity.

Interest incurred on funds borrowed to finance capital projects is capitalized until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2013, 2012, and 2011, was $64 million, $104 million, and $80 million, respectively.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis which approximates the effective interest method over the term of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by NRG. The Company recognizes specifically identifiable intangible assets including customer contracts, customer relationships, energy supply contracts, marketing partnerships, development rights, trade names, emission allowances, and fuel contracts when specific rights and contracts are acquired. In addition, NRG also established values for emission allowances and power contracts upon adoption of Fresh Start reporting. These intangible assets are amortized based on expected volumes, expected delivery, expected discounted future net cash flows, straight line or units of production basis.

Intangible assets determined to have indefinite lives are not amortized, but rather are tested for impairment at least annually or more frequently if events or changes in circumstances indicate that such acquired intangible assets have been determined to have finite lives and should now be amortized over their useful lives. NRG had no intangible assets with indefinite lives recorded as of December 31, 2013.

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

Goodwill

In accordance with ASC 350, the Company recognizes goodwill for the excess cost of an acquired entity over the net value assigned to assets acquired and liabilities assumed. NRG performs goodwill impairment tests annually, during the fourth quarter, and when events or changes in circumstances indicate that the carrying value may not be recoverable.

In September 2011, the FASB issued ASU No. 2011-08, Intangibles - Goodwill and Other (Topic 350) Testing Goodwill for Impairment, or ASU No. 2011-08. The objective of ASU 2011-08 is to simplify how entities test goodwill for impairment. The amendments in ASU No. 2011-08 permit an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in Topic 350. The more-likely-than-not threshold is defined as having a likelihood of more than 50 percent. The Company adopted the provisions of ASU No. 2011-08, effective January 1, 2011, with no impact on its results of operations, financial position or cash flows.

In the absence of sufficient qualitative factors, goodwill impairment is determined using a two step process:

Step one —	Identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value exceeds book value, goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, proceed to step two.
Step two —	Compare the implied fair value of the reporting unit's goodwill to the book value of the reporting unit goodwill. If the book value of goodwill exceeds fair value, an impairment charge is recognized for the sum of such excess.

Income Taxes

NRG accounts for income taxes using the liability method in accordance with ASC 740, which requires that the Company use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

NRG has two categories of income tax expense or benefit — current and deferred, as follows:

- Current income tax expense or benefit consists solely of current taxes payable less applicable tax credits, and
- Deferred income tax expense or benefit is the change in the net deferred income tax asset or liability, excluding amounts charged or credited to accumulated other comprehensive income.

NRG reports some of the Company's revenues and expenses differently for financial statement purposes than for income tax return purposes, resulting in temporary and permanent differences between the Company's financial statements and income tax returns. The tax effects of such temporary differences are recorded as either deferred income tax assets or deferred income tax liabilities in the Company's consolidated balance sheets. NRG measures the Company's deferred income tax assets and deferred income tax liabilities using income tax rates that are currently in effect. The Company believes it is more likely than not that the results of future operations will generate sufficient taxable income which includes the future reversal of existing taxable temporary differences to realize deferred tax assets, net of valuation allowances. In arriving at this conclusion to utilize projections of future profit before tax in our estimate of future taxable income, the Company considered the profit before tax generated in recent years. A valuation allowance is recorded to reduce the Company's net deferred tax assets to an amount that is more-likely-than-not to be realized.

NRG reduces its current income tax expense in the consolidated statement of operations for any investment tax credits, or ITCs, that are not convertible into cash grants, as well as other tax credits, in the period the tax credit is generated. ITCs that are convertible into cash grants, as well as the deferred income tax benefit generated by the difference in the financial statement and tax basis of the related assets, are recorded as a reduction to the carrying value of the underlying property and subsequently amortized to earnings on a straight-line basis over the useful life of each underlying property.

The Company accounts for uncertain tax positions in accordance with ASC 740, which applies to all tax positions related to income taxes. Under ASC 740, tax benefits are recognized when it is more-likely-than-not that a tax position will be sustained upon examination by the authorities. The benefit recognized from a position that has surpassed the more-likely-than-not threshold is the largest amount of benefit that is more than 50% likely to be realized upon settlement. The Company recognizes interest and penalties accrued related to uncertain tax benefits as a component of income tax expense.

In accordance with ASC 805 and as discussed further in Note 19, Income Taxes, changes to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, are recorded to income tax expense.

Revenue Recognition

Energy — Both physical and financial transactions are entered into to optimize the financial performance of NRG's generating facilities. Electric energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in the Company's consolidated statements of operations. Financial transactions, or the buying and selling of energy for trading purposes, are recorded net within operating revenues in the consolidated statements of operations in accordance with ASC 815.

Capacity — Capacity revenues are recognized when contractually earned, and consist of revenues billed to a third party at either the market or a negotiated contract price for making installed generation capacity available in order to satisfy system integrity and reliability requirements.

Sale of Emission Allowances — NRG records the Company's bank of emission allowances as part of the Company's intangible assets. From time to time, management may authorize the transfer of emission allowances in excess of usage from the Company's emission bank to intangible assets held-for-sale for trading purposes. NRG records the sale of emission allowances on a net basis within operating revenue in the Company's consolidated statements of operations.

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

Retail revenues — Gross revenues for energy sales and services to retail customers are recognized upon delivery under the accrual method. Energy sales and services that have been delivered but not billed by period end are estimated. Gross revenues also includes energy revenues from resales of purchased power, which were $166 million, $151 million and $186 million for the years ended December 31, 2013, 2012, and 2011, respectively. These revenues represent the sale of excess supply to third parties in the market.

Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed. NRG recorded receivables for unbilled revenues of $356 million, $338 million and $318 million as of December 31, 2013, 2012, and 2011, respectively, for retail energy sales and services.

PPAs — Certain of the Company's revenues are currently obtained through PPAs or other contractual arrangements. All of these PPAs are recorded as operating leases in accordance with ASC 840, Leases, or ASC 840. ASC 840 requires minimum lease payments received to be amortized over the term of the lease and contingent rentals are recorded when the achievement of the contingency becomes probable. These leases have no minimum lease payments and all the rent is recorded as contingent rent on an actual basis when the electricity is delivered. The contingent rental income recognized in the years ended December 31, 2013, 2012, and 2011 was $400 million, $130 million, and $27 million, respectively.

Gross Receipts and Sales Taxes

In connection with its Retail Business, the Company records gross receipts taxes on a gross basis in revenues and cost of operations in its consolidated statements of operations. During the years ended December 31, 2013, 2012, and 2011, NRG's revenues and cost of operations included gross receipts taxes of $88 million, $79 million, and $78 million respectively. Additionally, the Retail Business records sales taxes collected from its taxable customers and remitted to the various governmental entities on a net basis, thus, there is no impact on the Company's consolidated statement of operations.

Cost of Energy for Retail Operations

The cost of energy for electricity sales and services to retail customers is based on estimated supply volumes for the applicable reporting period. A portion of the cost of energy ($90 million, $97 million and $87 million as of December 31, 2013, 2012, and 2011, respectively) was accrued and consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities. In estimating supply volumes, the Company considers the effects of historical customer volumes, weather factors and usage by customer class. Transmission and distribution delivery fees are estimated using the same method used for electricity sales and services to retail customers. In addition, ISO fees are estimated based on historical trends, estimated supply volumes and initial ERCOT ISO settlements. Volume estimates are then multiplied by the supply rate and recorded as cost of operations in the applicable reporting period.

Derivative Financial Instruments

NRG accounts for derivative financial instruments under ASC 815, which requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a NPNS exception. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges, if elected for hedge accounting, are either:

- Recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments; or
- Deferred and recorded as a component of accumulated OCI until the hedged transactions occur and are recognized in earnings.

NRG's primary derivative instruments are power sales contracts, fuels purchase contracts, other energy related commodities, and interest rate instruments used to mitigate variability in earnings due to fluctuations in market prices and interest rates. On an ongoing basis, NRG assesses the effectiveness of all derivatives that are designated as hedges for accounting purposes in order to determine that each derivative continues to be highly effective in offsetting changes in fair values or cash flows of hedged items. Internal analyses that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such an energy contract designated as a hedge. If it is determined that the derivative instrument is not highly effective as a hedge, hedge accounting will be discontinued prospectively. Hedge accounting will also be discontinued on contracts related to commodity price risk previously accounted for as cash flow hedges when it is probable that delivery will not be made against these contracts. In this case, the gain or loss previously deferred in accumulated OCI would be immediately reclassified into earnings. If the derivative instrument is terminated, the effective portion of this derivative deferred in accumulated OCI will be frozen until the underlying hedged item is delivered.

Revenues and expenses on contracts that qualify for the NPNS exception are recognized when the underlying physical transaction is delivered. While these contracts are considered derivative financial instruments under ASC 815, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception, the fair value of the related contract is recorded on the balance sheet and

immediately recognized through earnings.
NRG's trading activities are subject to limits in accordance with the Company's Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG's foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the Company's statements of operations for the period, but are accumulated and reported as a separate component of stockholders' equity until sale or complete or substantially complete liquidation of the net investment in the foreign entity takes place. Foreign currency transaction gains or losses are reported within other income/(expense) in the Company's statements of operations. For the years ended December 31, 2013, 2012, and 2011, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2013, 2012, and 2011 were $15 million, $53 million and $72 million, respectively.

Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trust funds, accounts receivable, notes receivable, derivatives, and investments in debt securities. Trust funds are held in accounts managed by experienced investment advisors. Certain accounts receivable, notes receivable, and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables and other contractual arrangements are subject to collateral requirements under the terms of enabling agreements. However, the Company believes that the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its customer base. See Note 4, Fair Value of Financial Instruments, for a further discussion of derivative concentrations.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, funds deposited by counterparties, receivables, accounts payables, and accrued liabilities approximate fair value because of the short-term maturity of these instruments. See Note 4, Fair Value of Financial Instruments for a further discussion of fair value of financial instruments.

Asset Retirement Obligations

NRG accounts for its AROs in accordance with ASC 410-20, Asset Retirement Obligations, or ASC 410-20. Retirement obligations associated with long-lived assets included within the scope of ASC 410-20 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. ASC 410-20 requires an entity to recognize the fair value of a liability for an ARO in the period in which it is incurred and a reasonable estimate of fair value can be made.

Upon initial recognition of a liability for an ARO, NRG capitalizes the asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount. Over time, the liability is accreted to its future value, while the capitalized cost is depreciated over the useful life of the related asset. See Note 13, Asset Retirement Obligations, for a further discussion of AROs.

Pensions and Other Postretirement Benefits

NRG offers pension benefits through a defined benefit pension plan. In addition, the Company provides postretirement health and welfare benefits for certain groups of employees. NRG accounts for pension and other postretirement benefits in accordance with ASC 715, Compensation — Retirement Benefits. NRG recognizes the funded status of the Company's defined benefit plans in the statement of financial position and records an offset for gains and losses as well as all prior service costs that have not been included as part of the Company's net periodic benefit cost to other comprehensive income. The determination of NRG's obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. NRG's actuarial consultants determine assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by the Company.

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

Stock-Based Compensation

NRG accounts for its stock-based compensation in accordance with ASC 718, Compensation — Stock Compensation, or ASC 718. The fair value of the Company's non-qualified stock options and performance units are estimated on the date of grant using the Black-Scholes option-pricing model and the Monte Carlo valuation model, respectively. NRG uses the Company's common stock price on the date of grant as the fair value of the Company's restricted stock units and deferred stock units. Forfeiture rates are estimated based on an analysis of NRG's historical forfeitures, employment turnover, and expected future behavior. The Company recognizes compensation expense for both graded and cliff vesting awards on a straight-line basis over the requisite service period for the entire award.

Investments Accounted for by the Equity Method

NRG has investments in various domestic energy projects, as well as one Australian project. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents NRG from exercising a controlling influence over the operating and financial policies of the projects. Under this method, equity in pre-tax income or losses of domestic partnerships and, generally, in the net income or losses of its Australian project, are reflected as equity in earnings of unconsolidated affiliates.

Marketing and Advertising Costs

The Company expenses its advertising and marketing costs as incurred. The costs of tangible assets used in advertising campaigns are recorded as fixed assets or deferred advertising costs and amortized as advertising costs over the shorter of the useful life of the asset or the advertising campaign. The Company has several long-term sponsorship arrangements. Payments related to these arrangements are deferred and expensed over the term of the arrangement. Marketing and advertising expenses included within selling, general and administrative expense for the years ended December 31, 2013, 2012, and 2011 were $195 million, $197 million, and $127 million respectively.

Business Combinations

The Company accounts for its business combinations in accordance with ASC 805, Business Combinations, or ASC 805. ASC 805 requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

Use of Estimates

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

In recording transactions and balances resulting from business operations, NRG uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of energy commodity contracts, environmental liabilities, legal costs incurred in connection with recorded loss contingencies, and assets acquired and liabilities assumed in business combinations, among others. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes.

Recent Accounting Developments
ASU 2011-11 - Effective January 1, 2013, the Company adopted the provisions of ASU No. 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, or ASU No. 2011-11, and began providing enhanced disclosures regarding the effect or potential effect of netting arrangements on an entity's financial position by improving information about financial instruments and derivative instruments that either (1) offset in accordance with either ASC 210-20-45 or ASC 810-20-45 or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. Reporting entities are required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The disclosures required by ASU No. 2011-11 are required to be adopted retroactively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Company's results of operations, cash flows or financial position.
ASU 2013-02 - Effective January 1, 2013, the Company adopted the provisions of ASU No. 2013-02, Other Comprehensive Income (Topic 220) Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, or ASU No. 2013-02, and began reporting the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income within the notes to the financial statements if the amount being reclassified is required under U.S. GAAP to be reclassified in its entirety to net income in the same reporting period. For other amounts not required by U.S. GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures which provide additional information about the amounts. The provisions of ASU No. 2013-02 are required to be adopted prospectively. As this guidance provides only presentation requirements, the adoption of this standard did not impact the Company's results of operations, cash flows or financial position.
Other - The following accounting standard was issued in 2013 and was adopted January 1, 2014:
•ASU 2013-11 - In July 2013, the FASB issued ASU No. 2013-11, Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, or ASU No. 2013-11. The amendments of ASU 2013-11 requires an entity to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, as a reduction of a deferred tax asset for a net operating loss, or NOL, a similar tax loss or tax credit carryforwards rather than a liability when the uncertain tax position would reduce the NOL or other carryforward under the tax law of the applicable jurisdiction and the entity intends to use the deferred tax asset for that purpose. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013 with early adoption permitted. The Company adopted this standard effective December 31, 2013. The adoption of this standard did not impact the Company's results of operations or cash flows as the unrecognized tax benefits relate to state issues and the Company either has no NOL's or the NOL's are limited for that particular jurisdiction.
Note 3 — Business Acquisitions and Dispositions
2013 Acquisitions
Pending Acquisition — On October 18, 2013, the Company entered into an agreement to acquire substantially all of the assets of Edison Mission Energy, or EME. EME, through its subsidiaries and affiliates, owns, operates, and leases a portfolio of 8,000 MW consisting of wind energy facilities and coal- and gas-fired generating facilities. On December 17, 2012, EME and certain of its direct and indirect subsidiaries filed voluntary petitions for relief under chapter 11 of title 11 of the United States Code, or the Bankruptcy Code. EME was deconsolidated from its parent company, Edison International, for financial statement purposes but not for tax purposes on December 17, 2012. On May 2, 2013, certain other subsidiaries of EME filed voluntary petitions for relief under the Bankruptcy Code.
The Company expects to pay an aggregate purchase price of $2.6 billion (subject to adjustment), which will consist of 12,671,977 shares of NRG common stock (valued at $350 million based upon the volume-weighted average trading price over the 20 trading days prior to October 18, 2013) with the balance to be paid in cash. The Company expects to fund the net cash portion of the purchase price using a combination of cash on hand, including acquired cash on hand of $1.1 billion, and approximately $700 million in newly-issued corporate debt. The Company also expects to assume debt related to acquired project assets of approximately $1.5 billion, which will be non-recourse to NRG.

In connection with the transaction, NRG has agreed to certain conditions with the parties to the Powerton and Joliet, or POJO, sale-leaseback transaction subject to which an NRG subsidiary will assume the POJO leveraged leases and NRG will guarantee the remaining payments under each lease. In connection with this agreement, NRG has committed to fund up to $350 million in capital expenditures for plant modifications at Powerton and Joliet to install controls to comply with MATS.

The acquisition is subject to customary conditions, including approval of the U.S. Bankruptcy Court for the Northern District of Illinois and required regulatory approvals, and is expected to close by the end of the first quarter of 2014. Under certain circumstances, including if EME enters into an alternative transaction, NRG will receive a cash fee of $65 million plus expense reimbursement. There are no assurances that the conditions to the acquisition of EME will be satisfied, that EME will not enter into an alternative transaction, or that the acquisition of EME will be consummated on the terms agreed to, if at all.

Energy Systems — On December 31, 2013, NRG Energy Center Omaha Holdings, LLC, an indirect wholly owned subsidiary of NRG Yield LLC, acquired 100% of Energy Systems Company, or Energy Systems, for approximately $120 million. The acquisition was financed from cash on hand. Energy Systems is an operator of steam and chilled thermal facilities that provides heating and cooling services to nonresidential customers in Omaha, Nebraska. The acquisition was recorded as a business combination under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The purchase price was primarily allocated to property, plant and equipment of $60 million, customer relationships of $59 million, and working capital of $1 million. The initial accounting for the business combination is not complete because the evaluations necessary to assess the fair values of certain net assets acquired and the amount of goodwill to be recognized are still in process. The provisional amounts are subject to revision until the evaluations are completed to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date.

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

•Customer relationships - The customer relationships were valued using a variation of the income approach. Under this approach, the present value of the expected future cash flows resulting from existing customer relationships, considering attrition and charges for contributory assets (such as working capital, fixed assets, and workforce) utilized in the business were estimated and then discounted back at an integrated utility peer group's weighted average cost of capital adjusted to be consistent with the risk inherent in the cash flows. The customer relationships are amortized to depreciation and amortization expense, on a straight-line basis, over 33 years.

Significant considerations in determining fair value measurements as defined in ASC 820 of the assets acquired and liabilities assumed are as follows:

•Property, plant & equipment - The fair value of property, plant and equipment acquired were valued utilizing the cost approach. Under this approach, the fair value approximates the current cost of replacing an asset with another of equivalent economic utility adjusted for functional obsolescence and physical depreciation.

Gregory — On August 7, 2013, NRG Texas Gregory, LLC, a wholly owned subsidiary of NRG, acquired Gregory Power Partners, L.P. for approximately $245 million in cash, net of $32 million cash acquired. Gregory is a cogeneration plant located in Corpus Christi, Texas, which has generation capacity of 388 MW and steam capacity of 160 MWt. The Gregory cogeneration plant provides steam, processed water and a small percentage of its electrical generation to the Corpus Christi Sherwin Alumina plant. The majority of the plant's generation is available for sale in the ERCOT market. The acquisition was recorded as a business combination under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The purchase price was provisionally allocated to property, plant, and equipment of $248 million, current assets of $13 million, and other liabilities of $16 million. The initial accounting for the business combination is not complete because the evaluations necessary to assess the fair value of certain net assets acquired are still in process. The provisional amounts are subject to revision until the evaluations are completed to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date.

Significant considerations in determining fair value measurements as defined in ASC 820 of the assets acquired and liabilities assumed are as follows:

•Property, plant & equipment - The fair value of property, plant and equipment acquired were valued utilizing the cost approach. Under this approach, the fair value approximates the current cost of replacing an asset with another of equivalent economic utility adjusted for functional obsolescence and physical depreciation.

2012 Acquisitions

GenOn Energy, Inc. — On December 14, 2012, NRG acquired GenOn Energy, Inc., or GenOn. GenOn, a generator of wholesale electricity, has baseload, intermediate and peaking power generation facilities using coal, natural gas and oil, totaling approximately 21,440 MW. The Company issued, as consideration for the acquisition, 0.1216 shares of NRG common stock for each outstanding share of GenOn, including restricted stock units outstanding, on the acquisition date, except for fractional shares which were paid in cash. The Company issued approximately 93.9 million shares of NRG common stock, or 29% of total common shares outstanding following the closing of the transaction. The acquisition was recorded as a business combination under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The accounting for the GenOn acquisition was completed on December 13, 2013 at which point the fair values became final. The provisional amounts were subject to revision until the evaluations were completed to the extent that additional information was obtained about the facts and circumstances that existed as of the acquisition date. Any changes made to the fair value assessments affected the gain on bargain purchase.

The following table summarizes the provisional amounts recognized for assets acquired and liabilities assumed as of the acquisition date as well as adjustments made through December 13, 2013 to the amounts initially recorded in 2012 due to the ongoing evaluation of initial estimates. The measurement period adjustments were recorded as an adjustment to the gain on bargain purchase and did not have a significant impact on the Company's consolidated cash flows or financial position in any period. The purchase price of $2.2 billion was allocated as follows:

(In millions)	Amounts Recognized as of Acquisition Date (as previously reported)	Measurement Period Adjustments	Amounts Recognized as of Acquisition Date (as adjusted)
Assets			
Cash	$983	$—	$983
Current and non-current assets	1,385	28	1,413
Property, plant and equipment	3,936	(115)	3,821
Derivative assets	1,157	—	1,157
Deferred income taxes	2,265	(58)	2,207
Total assets acquired	$9,726	$(145)	$9,581
Liabilities			
Current and non-current liabilities	$1,312	$54	$1,366
Out-of-market contracts and leases	1,064	62	1,126
Derivative liabilities	399	—	399
Long-term debt and capital leases	4,203	3	4,206
Total liabilities assumed	6,978	119	7,097
Net assets acquired	2,748	(264)	2,484
Consideration paid	2,188		2,188
Gain on bargain purchase	$560	$(264)	$296

The measurement period adjustments for property, plant and equipment and out-of market liabilities primarily reflect revisions of various estimates based on additional information available. In addition, measurement period adjustments were recorded for additional environmental reserves resulting from further review and revisions to various estimates. The difference between the historical tax basis of the assets and liabilities over the net amount assigned to the assets and liabilities in acquisition accounting was recorded as a net deferred tax asset. In addition, the deferred tax assets associated with net operating losses and other deferred tax benefits were adjusted to reflect the amount expected to be realized in the post-acquisition period.

2012 Dispositions

Agua Caliente — On January 18, 2012, the Company completed the sale of a 49% interest in NRG Solar AC Holdings LLC, the indirect owner of the Agua Caliente project, to MidAmerican Energy Holdings Company, or MidAmerican. A majority of the $122 million of cash consideration received at closing represented 49% of construction costs funded by NRG's equity contributions. The excess of the consideration over the carrying value of the divested interest was recorded to additional paid-in capital. MidAmerican will fund its proportionate share of future equity contributions and other credit support for the project. NRG continues to hold a majority interest in and consolidate the project.

Saale Energie GmbH — On July 17, 2012, the Company completed the sale of its 100% interest in Saale Energie GmbH, or SEG, which holds a 41.9% interest in Kraftwerke Schkopau GbR and a 44.4% interest in Kraftwerke Schkopau Betriebsgesllschaft mbH, collectively, Schkopau. Schkopau holds a fixed 400 MW participation in the 900 MW Schkopau Power Station located in Germany. In connection with the sale of Schkopau, NRG entered into a foreign currency swap contract to hedge the impact of exchange rate fluctuations on the sale proceeds of €141 million. The Company received cash consideration, net of selling expenses, of $174 million, which included $4 million related to the settlement of the swap contract that was recorded as a gain within Other income, net in the quarter ended September 30, 2012. The cash consideration approximated the book value of the net assets, including cash of $38 million, on the date of the sale.

2011 Acquisitions

Energy Plus — On September 30, 2011, NRG acquired Energy Plus for $194 million in cash, net of $5 million cash acquired, funded from cash on hand. Energy Plus is a retail electricity provider with 188,000 customers as of December 31, 2011, concentrated in the Northeast markets, and a unique sales channel involving exclusive loyalty and affinity program partnerships. The acquisition was recorded as a business combination under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The purchase price was primarily allocated to customer relationships of $63 million, marketing partnerships of $88 million, trade names of $10 million and goodwill of $29 million. The factors that resulted in goodwill arising from the acquisition include the revenues associated with expanding the Energy Plus retail business and its unique sales channel in new regions, expanding its loyalty and affinity program partnerships and the synergies associated with combining the business with NRG's generation assets. The accounting for the Energy Plus acquisition was completed as of March 31, 2012, at which point the provisional fair values became final with no material changes.

Solar Acquisitions — During the year ended December 31, 2011, NRG acquired stakes in three Utility Scale Solar facilities for approximately $165 million in cash consideration, as part of the Company's initiative to capture opportunities for future growth in renewables. Subsequent to the acquisition dates in 2011, NRG made capital contributions into these projects of $868 million. In addition, NRG has a commitment to contribute additional amounts into the projects, comprised of $66 million in letters of credit as of December 31, 2013. The Company may increase its letters of credit to replace the restricted cash at its discretion. NRG's minority partners had contributed approximately $413 million of equity subsequent to the acquisition through December 31, 2013 and had additional equity commitments of $64 million as of December 31, 2013. These acquisitions were recorded as business combinations under ASC 805, with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date.

The acquisitions of these three solar facilities are further described below:

California Valley Solar Ranch — On September 30, 2011, NRG Solar LLC, a wholly-owned subsidiary of NRG, acquired 100% of the 250 MW California Valley Solar Ranch project, or CVSR, in eastern San Luis Obispo County, California. During the second quarter of 2012, the Company met the conditions necessary to permit loan disbursements under the CVSR Financing Agreement, as discussed in Note 12, Debt and Capital Leases. Operations commenced on the first 22 MW phase in September 2012 and 105 MWs for Phases 2 and 4 in December 2012. For the completion of the final phase, 21 MWs commenced operation in the third quarter of 2013 and 102 MWs commenced operation in October 2013. Power generated from CVSR is sold to PG&E under a 25 year PPA.

Agua Caliente — On August 5, 2011, NRG, through its wholly-owned subsidiary, NRG Solar PV LLC, acquired 100% of the 290 MW Agua Caliente solar project in Yuma, AZ. On January 18, 2012, the Company completed the sale of a 49% interest to MidAmerican Energy Holdings Company as discussed above. Power generated from Agua Caliente is sold to PG&E under a 25 year PPA. Full commercial operations of the entire 290 MW project was achieved as of September 30, 2013.

Ivanpah — On April 5, 2011, NRG acquired a 50.1% stake in the 378 MW Ivanpah Solar Electric Generation System, or Ivanpah, from BrightSource Energy, Inc., or BSE. BSE maintained a 21.8% interest in Ivanpah and the remaining 28.1% was acquired by a wholly-owned subsidiary of Google. Ivanpah is composed of three separate facilities - Ivanpah 1 (126 MW), Ivanpah 2 (133 MW), and Ivanpah 3 (133 MW). Ivanpah achieved operations as of December

31, 2013. Power generated from Ivanpah is sold to Southern California Edison and Pacific Gas and Electric, under multiple 20 to 25 year PPAs.
The purchase price for these acquisitions, considered business combinations, was primarily allocated to $767 million of property, plant and equipment, $489 million of accrued expenses, $60 million of other assets, including restricted cash, and $19 million of other liabilities. The accounting for these acquisitions was completed as of March 31, 2012, at which point the provisional fair values became final with no material changes.

Note 4 — Fair Value of Financial Instruments

For cash and cash equivalents, funds deposited by counterparties, accounts and other receivables, accounts payable, restricted cash, and cash collateral paid and received in support of energy risk management activities, the carrying amount approximates fair value because of the short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

The estimated carrying values and fair values of NRG's recorded financial instruments not carried at fair market value are as follows:

	As of December 31,			
	2013		2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets				
Notes receivable [(a)]	$99	$99	$88	$88
Liabilities				
Long-term debt, including current portion	16,804	17,222	15,866	16,492

(a) Includes the current portion of notes receivable which is recorded in prepayments and other current assets on the Company's consolidated balance sheets.

The fair value of the Company's publicly-traded long-term debt is based on quoted market prices and is classified as Level 2 within the fair value hierarchy. The fair value of debt securities, non publicly-traded long-term debt, and certain notes receivable of the Company are based on expected future cash flows discounted at market interest rates, or current interest rates for similar instruments with equivalent credit quality and are classified as Level 3 within the fair value hierarchy.

Fair Value Accounting under ASC 820

ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access as of the measurement date. NRG's financial assets and liabilities utilizing Level 1 inputs include active exchange-traded securities, energy derivatives, and trust fund investments.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. NRG's financial assets and liabilities utilizing Level 2 inputs include fixed income securities, exchange-based derivatives, and over the counter derivatives such as swaps, options and forward contracts.
- Level 3 — unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date. NRG's financial assets and liabilities utilizing Level 3 inputs include infrequently-traded, non-exchange-based derivatives and commingled investment funds, and are measured using present value pricing models.

In accordance with ASC 820, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety.

Recurring Fair Value Measurements

Debt securities, equity securities, and trust fund investments, which are comprised of various U.S. debt and equity securities, and derivative assets and liabilities, are carried at fair market value.

The following tables present assets and liabilities measured and recorded at fair value on the Company's consolidated balance sheets on a recurring basis and their level within the fair value hierarchy:

	As of December 31, 2013			
	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$—	$—	$16	$16
Available-for-sale securities	2	—	—	2
Other [(a)]	37	—	10	47
Nuclear trust fund investments:				
Cash and cash equivalents	26	—	—	26
U.S. government and federal agency obligations	40	5	—	45
Federal agency mortgage-backed securities	—	62	—	62
Commercial mortgage-backed securities	—	14	—	14
Corporate debt securities	—	70	—	70
Equity securities	276	—	56	332
Foreign government fixed income securities	—	2	—	2
Other trust fund investments:				
U.S. government and federal agency obligations	1	—	—	1
Derivative assets:				
Commodity contracts	346	1,126	147	1,619
Interest rate contracts	—	20	—	20
Total assets	$728	$1,299	$229	$2,256
Derivative liabilities:				
Commodity contracts	$216	$831	$134	$1,181
Interest rate contracts	—	69	—	69
Total liabilities	$216	$900	$134	$1,250

(a) Consists primarily of mutual funds held in a Rabbi Trust for non-qualified deferred compensation plans for some key and highly compensated employees and a total return swap that does not meet the definition of a derivative.

	As of December 31, 2012			
	Fair Value			
	Level 1	Level 2	Level 3	Total
	(In millions)			
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$—	$—	$12	$12
Other [(a)]	22	—	—	22
Nuclear trust fund investments:				
Cash and cash equivalents	10	—	—	10
U.S. government and federal agency obligations	33	—	—	33
Federal agency mortgage-backed securities	—	59	—	59
Commercial mortgage-backed securities	—	9	—	9
Corporate debt securities	—	80	—	80
Equity securities	233	—	47	280
Foreign government fixed income securities	—	2	—	2
Other trust fund investments:				
U.S. government and federal agency obligations	1	—	—	1
Derivative assets:				
Commodity contracts	1,457	1,711	135	3,303
Interest rate contracts	—	3	—	3
Total assets	$1,756	$1,864	$194	$3,814
Derivative liabilities:				
Commodity contracts	$1,144	$1,047	$147	$2,338
Interest rate contracts	—	143	—	143
Total liabilities	$1,144	$1,190	$147	$2,481

(a) Consists primarily of mutual funds held in a Rabbi Trust for non-qualified deferred compensation plans for some key and highly compensated employees.

There have been no transfers during the year ended December 31, 2013, between Levels 1 and 2. The following tables reconcile, for the years ended December 31, 2013, and 2012, the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements at least annually using significant unobservable inputs:

	For the Year Ended December 31, 2013				
	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)				
	Debt Securities	Other	Trust Fund Investments	Derivatives [(a)]	Total
	(In millions)				
Beginning balance as of January 1, 2013	$12	$—	$47	$ (12)	$47
Total gains and losses (realized/unrealized):					
Included in OCI	4	—	—	—	4
Included in earnings	—	—	—	(12)	(12)
Included in nuclear decommissioning obligations	—	—	10	—	10
Purchases	—	10	2	4	16
Sales	—	—	(3)	—	(3)
Transfers into Level 3 [(b)]	—	—	—	6	6
Transfers out of Level 3 [(b)]	—	—	—	27	27
Ending balance as of December 31, 2013	$16	$10	$56	$ 13	$95
	$—	$—	$—	$ 1	$1

Gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets or liabilities still held as of December 31, 2013	

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

(b) Transfers in/out of Level 3 are related to the availability of external broker quotes, and are valued as of the end of the reporting period. All transfers in/out are with Level 2.

	For the Year Ended December 31, 2012 Fair Value Measurement Using Significant Unobservable Inputs (Level 3)			
	Debt Securities (In millions)	Trust Fund Investments	Derivatives [a]	Total
Beginning balance as of January 1, 2012	$7	$42	$ 8	$57
Total gains and losses (realized/unrealized):				
Included in OCI	5	—	—	5
Included in earnings	—	—	(13)	(13)
Included in nuclear decommissioning obligations	—	5	—	5
Purchases	—	—	8	8
Contracts acquired in GenOn acquisition	—	—	18	18
Transfers into Level 3 [b]	—	—	(33)	(33)
Transfer out of Level 3 [b]	—	—	—	—
Ending balance as of December 31, 2012	$12	$47	$ (12)	$47
Losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets or liabilities still held as of December 31, 2012	$—	$—	$ (3)	$(3)

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

(b) Transfers in/out of Level 3 are related to the availability of external broker quotes, and are valued as of the end of the reporting period. All transfers in/out are with Level 2.

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

Non-derivative fair value measurements

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

The trust fund investments are held primarily to satisfy NRG's nuclear decommissioning obligations. These trust fund investments hold debt and equity securities directly and equity securities indirectly through commingled funds. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. In addition, U.S. government and federal agency obligations are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of corporate debt securities are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized in Level 2. Certain equity securities, classified as commingled funds, are analogous to mutual funds, are maintained by investment companies, and hold certain investments in accordance with a stated set of fund objectives. The fair value of the equity securities classified as commingled funds are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares in the commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See also Note 6, Nuclear Decommissioning Trust Fund.

Derivative fair value measurements

A portion of NRG's contracts are exchange-traded contracts with readily available quoted market prices. A majority of NRG's contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company's prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote, then the mid-point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. A significant portion of the fair value of the Company's derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate those transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represents contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up 9% of derivative assets and 11% of derivative liabilities. The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that NRG's net exposure under a specific master agreement is an asset, the Company uses the counterparty's default swap rate. If the exposure under a specific master agreement is a liability, the Company uses NRG's default swap rate. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG's liabilities or that a market participant would be willing to pay for NRG's assets. As of December 31, 2013, the credit reserve resulted in a $1 million decrease in fair value which is reflected as a $1 million loss in operating revenue and cost of operations.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2013, and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts NRG holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible, however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

Under the guidance of ASC 815, entities may choose to offset cash collateral paid or received against the fair value of derivative positions executed with the same counterparties under the same master netting agreements. The Company has chosen not to offset positions as defined in ASC 815. As of December 31, 2013, the Company recorded $276 million of cash collateral paid and $63 million of cash collateral received on its balance sheet.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, Summary of Significant Accounting Policies, the following item is a discussion of the concentration of credit risk for the Company's financial instruments. Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties' credit limits; (iii) the use of credit mitigation measures such as margin, collateral, prepayment arrangements, or volumetric limits; (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty risk by having a diversified portfolio of counterparties. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at NRG to cover the credit risk of the counterparty until positions settle.

As of December 31, 2013, counterparty credit exposure, excluding credit risk exposure under certain long term agreements, was $813 million and NRG held collateral (cash and letters of credit) against those positions of $5 million, resulting in a net exposure of $808 million. Approximately 87% of the Company's exposure before collateral is expected to roll off by the end of 2015. Counterparty credit exposure is valued through observable market quotes and discounted at a risk free interest rate. The following tables highlight net counterparty credit exposure by industry sector and by counterparty credit quality. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and NPNS, and non-derivative transactions. The exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure (a) (% of Total)	
Financial institutions	52	%
Utilities, energy merchants, marketers and other	29	
Coal and emissions	1	
ISOs	18	
Total	100	%

Category	Net Exposure [(a)] (% of Total)	
Investment grade	94	%
Non-Rated	6	
Total	100	%

(a) Counterparty credit exposure excludes uranium and coal transportation contracts because of the unavailability of market prices.

NRG has counterparty credit risk exposure to certain counterparties, each of which represent more than 10% of total net exposure discussed above. The aggregate of such counterparties' exposure was $349 million. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company's financial position or results of operations from nonperformance by any of NRG's counterparties.

Counterparty credit exposure described above excludes credit risk exposure under certain long term agreements, including California tolling agreements, South Central load obligations, solar PPAs, and a coal supply agreement. As external sources or observable market quotes are not available to estimate such exposure, the Company values these contracts based on various techniques including, but not limited to, internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Based on these valuation techniques, as of December 31, 2013, aggregate credit risk exposure managed by NRG to these counterparties was approximately $2.3 billion, including $797 million related to assets of NRG Yield, Inc., for the next five years. This amount excludes potential credit exposures for projects with long term PPAs that have not reached commercial operations. The majority of these power contracts are with utilities or public power entities with strong credit quality and public utility commission or other regulatory support. However, such regulated utility counterparties can be impacted by changes in government regulations, which NRG is unable to predict. In the case of the coal supply agreement, NRG holds a lien against the underlying asset which significantly reduces the risk of loss.

Retail Customer Credit Risk

NRG is exposed to retail credit risk through the Company's retail electricity providers, which serve C&I customers and the Mass market. Retail credit risk results when a customer fails to pay for services rendered. The losses may result from both nonpayment of customer accounts receivable and the loss of in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of December 31, 2013, the Company's retail customer credit exposure to C&I customers was diversified across many customers and various industries, as well as government entities.

NRG is also exposed to retail customer credit risk relating to its Mass customers, which may result in a write-off of bad debt. The Company's bad debt expense was $67 million and $45 million for the years ending December 31, 2013 and 2012, respectively. Current economic conditions may affect the Company's customers' ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Note 5 — Accounting for Derivative Instruments and Hedging Activities

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

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivative and the hedged transaction are recorded in current earnings.

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

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

Energy-Related Commodities

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

- Forward contracts, which commit NRG to purchase or sell energy commodities or purchase fuels in the future.
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.
- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual, or notional, quantity.
- Option contracts, which convey to the option holder the right but not the obligation to purchase or sell a commodity.
- Extendable swaps, which include a combination of swaps and options executed simultaneously for different periods. This combination of instruments allows NRG to sell out-year volatility through call options in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. The above-market swap combined with its later-year call option are priced in aggregate at market at the trade's inception.
- Weather and hurricane derivative products used to mitigate a portion of Reliant Energy's lost revenue due to weather.

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

- Fixing the price for a portion of anticipated future electricity sales that provides an acceptable return on the Company's electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of NRG's power plants.
- Fixing the price of a portion of anticipated power purchases for the Company's retail sales.

NRG's trading and hedging activities are subject to limits within the Company's Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

As of December 31, 2013, NRG's derivative assets and liabilities consisted primarily of the following:

- Forward and financial contracts for the purchase/sale of electricity and related products economically hedging NRG's generation assets' forecasted output or NRG's retail load obligations through 2019.
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG's generation assets through 2017.
- Cash flow hedge energy-related derivative financial instruments extending through December 2015.

Also, as of December 31, 2013, NRG had other energy-related contracts that did not meet the definition of a derivative instrument or qualified for the NPNS exception and were therefore exempt from fair value accounting treatment as follows:

- Load-following forward electric sale contracts extending through 2026;
- Power Tolling contracts through 2038;
- Coal purchase contract through 2020;
- Power transmission contracts through 2015;
- Natural gas transportation contracts and storage agreements through 2028; and
- Coal transportation contracts through 2020.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company's issuance of variable and fixed rate debt. In order to manage the Company's interest rate risk, NRG enters into interest rate swap agreements. As of December 31, 2013, NRG had interest rate derivative instruments on non-recourse debt extending through 2030, the majority of which are designated as cash flow hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG's open derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of December 31, 2013 and 2012. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

Commodity	Units	Total Volume December 31, 2013	December 31, 2012
		(In millions)	
Emissions	Short Ton	—	(1)
Coal	Short Ton	51	37
Natural Gas	MMBtu	(166)	(413)
Oil	Barrel	1	1
Power	MWh	(27)	(14)
Interest	Dollars	$1,444	$2,612

The decrease in the natural gas position was the result of additional purchases entered into during the year to hedge our retail portfolio as well as the settlement of positions during the period. These amounts were slightly offset by natural gas sales entered into during the year to hedge our conventional power generation. The decrease in the interest rate position was primarily the result of the settlement of interest rate swaps.

Fair Value of Derivative Instruments

The following table summarizes the fair value within the derivative instrument valuation on the balance sheet:

	Fair Value			
	Derivative Assets		Derivative Liabilities	
(In millions)	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$—	$—	$35	$29
Interest rate contracts long-term	14	3	29	96
Commodity contracts current	—	—	1	3
Commodity contracts long-term	—	—	1	1
Total Derivatives Designated as Cash Flow or Fair Value Hedges	14	3	66	129
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	—	—	4	7
Interest rate contracts long-term	6	—	1	11
Commodity contracts current	1,328	2,644	1,015	1,942
Commodity contracts long-term	291	659	164	392
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	1,625	3,303	1,184	2,352
Total Derivatives	$1,639	$3,306	$1,250	$2,481

The Company has elected to present derivative assets and liabilities on the balance sheet on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. In addition, collateral received or paid on the Company's derivative assets or liabilities are recorded on a separate line item on the balance sheet. The following table summarizes the offsetting derivatives by counterparty master agreement level and collateral received or paid:

	Gross Amounts Not Offset in the Statement of Financial Position			
As of December 31, 2013	Gross Amounts of Recognized Assets/Liabilities (in millions)	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
Commodity contracts:				
Derivative assets	$1,619	$(1,032)	$(62)	$525
Derivative liabilities	(1,181)	1,032	18	(131)
Total commodity contracts	438	—	(44)	394
Interest rate contracts:				
Derivative assets	20	(12)	—	8
Derivative liabilities	(69)	12	—	(57)
Total interest rate contracts	(49)	—	—	(49)
Total derivative instruments	$389	$—	$(44)	$345

As of December 31, 2012	Gross Amounts of Recognized Assets/Liabilities (in millions)	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
	Gross Amounts Not Offset in the Statement of Financial Position			
Commodity contracts:				
Derivative assets	$3,303	$(2,024)	$(374)	$905
Derivative liabilities	(2,338)	2,024	28	(286)
Total commodity contracts	965	—	(346)	619
Interest rate contracts:				
Derivative assets	3	—	—	3
Derivative liabilities	(143)	—	—	(143)
Total interest rate contracts	(140)	—	—	(140)
Total derivative instruments	$825	$—	$(346)	$479

Accumulated Other Comprehensive Income

The following tables summarize the effects on NRG's accumulated OCI balance attributable to cash flow hedge derivatives, net of tax:

	Year Ended December 31, 2013		
	Energy Commodities (In millions)	Interest Rate	Total
Accumulated OCI balance at December 31, 2012	$41	$(72)	$(31)
Reclassified from accumulated OCI to income:			
Due to realization of previously deferred amounts	(51)	20	(31)
Mark-to-market of cash flow hedge accounting contracts	9	30	39
Accumulated OCI balance at December 31, 2013, net of $14 tax	(1)	(22)	(23)
Losses expected to be realized from OCI during the next 12 months, net of $8 tax	$(1)	$(14)	$(15)

There were no gains or losses recognized in income from the ineffective portion of cash flow hedges for the year ended December 31, 2013.

	Year Ended December 31, 2012		
	Energy Commodities (In millions)	Interest Rate	Total
Accumulated OCI balance at December 31, 2011	$188	$(56)	$132
Reclassified from accumulated OCI to income:			
Due to realization of previously deferred amounts	(144)	23	(121)
Mark-to-market of cash flow hedge accounting contracts	(3)	(39)	(42)
Accumulated OCI balance at December 31, 2012, net of $7 tax	$41	$(72)	$(31)
Losses recognized in income from the ineffective portion of cash flow hedges	$(51)	$—	$(51)

	Year Ended December 31, 2011		
	Energy Commodities	Interest Rate Contracts	Total
	(In millions)		
Accumulated OCI balance at December 31, 2010	$488	$(47)	$441
Reclassified from accumulated OCI to income:			
Due to realization of previously deferred amounts	(374)	12	(362)
Mark-to-market of cash flow hedge accounting contracts	74	(21)	53
Accumulated OCI balance at December 31, 2011, net of $87 tax	$188	$(56)	$132
Gains recognized in income from the ineffective portion of cash flow hedges	$28	$3	$31

Amounts reclassified from accumulated OCI into income and amounts recognized in income from the ineffective portion of cash flow hedges are recorded to operating revenue for commodity contracts and interest expense for interest rate contracts.

Accounting guidelines require a high degree of correlation between the derivative and the hedged item throughout the period in order to qualify as a cash flow hedge. As of April 30, 2012, the Company's regression analysis for natural gas prices to ERCOT power prices, while positively correlated, did not meet the required threshold for cash flow hedge accounting for calendar year 2012. As a result, the Company de-designated its 2012 ERCOT cash flow hedges as of April 30, 2012, and prospectively marked these derivatives to market through the income statement.

Impact of Derivative Instruments on the Statement of Operations

Unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedges and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that have not been designated as cash flow hedges, ineffectiveness on cash flow hedges, and trading activity on NRG's statement of operations. The effect of commodity hedges is included within operating revenues and cost of operations and the effect of interest rate hedges is included in interest expense.

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Unrealized mark-to-market results			
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(105)	$(247)	$54
Reversal of (gain)/loss positions acquired as part of the Reliant Energy, Green Mountain Energy and GenOn acquisitions	(357)	20	107
Net unrealized gains/(losses) on open positions related to economic hedges	177	10	(33)
(Losses)/gains on ineffectiveness associated with open positions treated as cash flow hedges	—	(51)	28
Total unrealized mark-to-market (losses)/gains for economic hedging activities	(285)	(268)	156
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	(50)	(60)	21
Net unrealized gains on open positions related to trading activity	7	46	42
Total unrealized mark-to-market (losses)/gains for trading activity	(43)	(14)	63
Total unrealized (losses)/gains	$(328)	$(282)	$219

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Unrealized (losses)/gains included in operating revenues	$(621)	$(464)	$388

Unrealized gains/(losses) included in cost of operations	293	182	(169)
Total impact to statement of operations — energy commodities	$(328)	$(282)	$219
Total impact to statement of operations — interest rate contracts	$15	$(8)	$2

The reversal of gain or loss positions acquired as part of the Reliant Energy, Green Mountain Energy and GenOn acquisitions were valued based upon the forward prices on the acquisition dates. The roll-off amounts were offset by realized gains or losses at the settled prices and are reflected in revenue or cost of operations during the same period.
For the year ended December 31, 2013, the $177 million gain from economic hedge positions was primarily the result of an increase in value of forward sales of natural gas and electricity due to a decrease in forward power and gas prices and an increase in value of forward purchases of coal due to an increase in forward coal prices.
As of June 30, 2013, NRG had interest rate swaps designated as cash flow hedges on the CVSR solar project. The notional amount on the swaps exceeded the actual debt draws on the project. As such, NRG discontinued cash flow hedge accounting for these contracts and $5 million of loss previously deferred in OCI was recognized in earnings for the year ended December 31, 2013.
For the year ended December 31, 2012, the $10 million gain from economic hedge positions was the result of an increase in value of forward sales of natural gas and electricity due to a decrease in forward power and gas prices offset by a decrease in value of forward purchases of coal due to a decrease in forward coal prices.
As of June 30, 2012 NRG had interest rate swaps designated as cash flow hedges on the Alpine solar project. The notional amount of the swaps exceeded the actual debt draws on the project. As such, NRG discontinued cash flow hedge accounting for these contracts and $4 million of loss previously deferred in OCI was recognized in earnings for the year ended December 31, 2012.

Credit Risk Related Contingent Features

Certain of the Company's hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed "adequate assurance" under the agreements, or require the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts that have adequate assurance clauses that are in net liability positions as of December 31, 2013, was $85 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2013, was $15 million. The Company is also a party to certain marginable agreements under which it has a net liability position, but the counterparty has not called for the collateral due, of approximately $34 million as of December 31, 2013.
See Note 4, Fair Value of Financial Instruments, for discussion regarding concentration of credit risk.

Note 6 — Nuclear Decommissioning Trust Fund

NRG's nuclear decommissioning trust fund assets, which are for the decommissioning of STP, are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. Although NRG is responsible for managing the decommissioning of its 44% interest in STP, the predecessor utilities that owned STP are authorized by the PUCT to collect decommissioning funds from their ratepayers to cover decommissioning costs on behalf of NRG. NRC requirements determine the decommissioning cost estimate which is the minimum required level of funding. In the event that funds from the ratepayers that accumulate in the nuclear decommissioning trust are ultimately determined to be inadequate to decommission the STP facilities, the utilities will be required to collect through rates charged to rate payers all additional amounts, with no obligation from NRG, provided that NRG has complied with PUCT rules and regulations regarding decommissioning trusts. Following completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective ratepayers of the utilities.

NRG accounts for the nuclear decommissioning trust fund in accordance with ASC 980, Regulated Operations, or ASC 980 because the Company's nuclear decommissioning activities are subject to approval by the PUCT, with regulated rates that are designed to recover all decommissioning costs and that can be charged to and collected from the ratepayers per PUCT mandate. Since the Company is in compliance with PUCT rules and regulations regarding decommissioning trusts and the cost of decommissioning is the responsibility of the Texas ratepayers, not NRG, all realized and unrealized gains or losses (including other-than-temporary impairments) related to the Nuclear Decommissioning Trust Fund are recorded to the Nuclear Decommissioning Trust Liability and are not included in net income or accumulated other comprehensive income, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses (including other-than-temporary impairments) for the securities held in the trust funds, as well as information about the contractual maturities of those securities.

	As of December 31, 2013				As of December 31, 2012		
(In millions, except otherwise noted)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)	Fair Value	Unrealized Gains [(a)]	Weighted-average maturities (in years)
Cash and cash equivalents	$26	$—	$—	—	$10	$—	—
U.S. government and federal agency obligations	45	1	1	9	33	2	10
Federal agency mortgage-backed securities	62	1	1	24	59	2	23
Commercial mortgage-backed securities	14	—	—	29	9	—	30
Corporate debt securities	70	1	1	9	80	4	11
Equity securities	332	204	—	—	280	143	—
Foreign government fixed income securities	2	—	—	9	2	—	6
Total	$551	$207	$3		$473	$151	

(a) There are no unrealized losses as of December 31, 2012.

The following table summarizes proceeds from sales of available-for-sale securities and the related realized gains and losses from these sales. The cost of securities sold is determined on the specific identification method.

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Realized gains	$25	$12	$4
Realized losses	(8)	(7)	(3)
Proceeds from sale of securities	488	399	385

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Note 7 — Inventory

Inventory consisted of:

	As of December 31,	
	2013	2012
	(In millions)	
Fuel oil	$259	$181
Coal/Lignite	290	405
Natural gas	15	12
Spare parts	316	301
Other	18	4
Total Inventory	$898	$903

Note 8 — Notes Receivable

Notes receivable primarily consisted of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. NRG's notes receivable and capital leases were as follows:

	As of December 31,	
	2013	2012
	(In millions)	
Notes receivable — non-affiliates [(a)]	$97	$82
Notes receivable — affiliate		
Avenal Solar Holdings LLC, indefinite maturity date, 4.5% [(b)]	2	6
Total notes receivable	99	88
Less current maturities [(c)]	26	9
Total notes receivable — noncurrent	$73	$79

(a) Primarily relates to Agua Caliente, Alpine, Borrego, El Segundo Energy Center and CVSR's agreements with their respective transmission owners to provide financing for required network upgrades. The notes will be repaid within a five year period following the date each facility reaches commercial operations.

(b) NRG entered into a long-term $35 million note receivable facility with Avenal Solar Holdings LLC, to fund project liquidity needs in 2011.

(c) The current portion of notes receivable is recorded in prepayments and other current assets on the consolidated balance sheets.

Note 9 — Property, Plant and Equipment

NRG's major classes of property, plant, and equipment were as follows:

	As of December 31,		Depreciable
	2013	2012	Lives
	(In millions)		
Facilities and equipment	$22,087	$19,571	1-40 Years
Land and improvements	801	793	
Nuclear fuel	463	414	5 Years
Office furnishings and equipment	298	355	2-10 Years
Construction in progress	2,775	4,428	
Total property, plant, and equipment	26,424	25,561	
Accumulated depreciation	(6,573)	(5,408)	
Net property, plant, and equipment	$19,851	$20,153	

Note 10 — Asset Impairments
2013 Impairment Losses
Indian River - Annually during the fourth quarter, the Company revises its views of power and fuel prices including the Company's fundamental view for long term prices in connection with the preparation of its annual budget. Changes to the Company’s views of long term power and fuel prices impacted the Company’s projections of profitability, based on management's estimate of supply and demand within the sub-markets for each plant and the physical and economic characteristics of each plant. The Company's revised views of projected profitability for Indian River resulted in a significant adverse change in the extent to which the assets are expected to be used. As a result, the Company considered this to be an indicator of impairment and performed an impairment test for these assets under ASC 360, Property, Plant and Equipment. The carrying amount of the assets was lower than the future net cash flows expected to be generated by the asset, considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. As a result, the assets are considered to be impaired, and the Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. The fair value of the assets was determined by factoring in the probability weighting of different courses of action available to the Company and included both an income approach and a market approach. The Company recorded an impairment loss related to Indian River in the fourth quarter of 2013 of $459 million.
Gladstone - During the fourth quarter of 2013, the Company reviewed its 37.5% interest in Gladstone for impairment utilizing the other-than-temporary impairment model under ASC 820, Fair Value Measurements, due to future market expectations as well as discussions with the managing joint venture participants regarding the plant's expected life. In determining fair value, the Company utilized an income approach and considered project specific assumptions for future project operating revenues and costs and expected plant operations. The carrying amount of the Company's equity method investment exceeded the fair value of the investment and the Company concluded that the decline is considered to be other than temporary. As a result, the Company measured the impairment loss as the difference between the carrying amount and fair value of the investment and recorded an impairment loss in the fourth quarter of 2013 of $92 million.
2011 Impairment Losses
Emissions Allowances - Under CSAPR, use of discounted Acid Rain SO_2 and CAIR NO_x allowances would have been discontinued and replaced with completely distinct allowance programs. Acid Rain allowances would still be required on a 1:1 basis under the Acid Rain Program. During the year ended December 31, 2011, the Company recorded an impairment charge of $160 million on the Company's Acid Rain Program SO_2 emission allowances in order to comply with the Acid Rain Program as discussed in Note 24, Environmental Matters.
Nuclear Innovation North America, LLC (NINA) - NINA is majority-owned subsidiary of NRG established to develop, finance and invest in new advanced design nuclear projects in select markets across North America, including the planned South Texas Project Units 3 and 4 Project, or STP 3 & 4. On March 11, 2011, Japan was hit by a devastating earthquake and tsunami which, in turn, triggered a nuclear incident at the Fukushima Daiichi Nuclear Power Station. The nuclear incident in Japan introduced multiple and substantial uncertainties around new nuclear development in the United States and the availability of debt and equity financing to NINA. Consequently, NINA announced, on March 21, 2011, that it was reducing the scope of development at the STP 3 & 4 expansion and suspended indefinitely all detailed engineering work and other pre-construction activities. As a result, NRG announced that, while it will cooperate with and support its current partners and any prospective future partners in attempting to develop STP 3 & 4 successfully, it was withdrawing from further financial participation in NINA's development of STP 3 & 4.
Due to the events described above, NRG evaluated its investment in NINA for impairment. As part of this process, NRG evaluated the contractual rights and economic interests held by the various stakeholders in NINA, and concluded that while it continues to hold majority legal ownership, NRG ceased to have a controlling financial interest in NINA at the end of the first quarter of 2011. Consequently, NRG deconsolidated NINA as of March 31, 2011, in accordance with ASC 810. Furthermore, NRG concluded it was remote that NRG would recover any portion of the carrying amount of its equity investment in NINA and, consequently, recorded impairment charges related to the full amount of its investment, as well as additional contributions made to support the reduced scope of work. The impairment charges

totaled $495 million for the year ended December 31, 2011. In 2012, NRG recorded an additional impairment charge related to additional contributions made of $2 million.

Note 11 — Goodwill and Other Intangibles

Goodwill — NRG's goodwill balance was $2.0 billion as of December 31, 2013 and 2012. The Company recorded approximately $1.7 billion of goodwill in connection with the acquisition of Texas Genco in 2006. The Company recorded $144 million of goodwill in connection with the 2010 acquisition of Green Mountain Energy, and $29 million in connection with the 2011 acquisition of Energy Plus. In 2013 and 2012, the Company recorded additional goodwill for several business acquisitions. The Energy Plus acquisition is discussed further in Note 3, Business Acquisitions and Dispositions. As of December 31, 2013, there was no impairment to goodwill. As of December 31, 2013, 2012, and 2011, NRG had approximately $573 million, $609 million, and $594 million, respectively, of goodwill that is deductible for U.S. income tax purposes in future periods.

Intangible Assets — The Company's intangible assets as of December 31, 2013, primarily reflect intangible assets established with the acquisitions of various companies in 2013, 2012, 2011, 2010, 2009, and 2006, and are comprised of the following:

- Emission Allowances — These intangibles primarily consist of SO_2 and NOx emission allowances established with the 2012 GenOn acquisition and 2006 Texas Genco acquisition and also include RGGI emission credits which NRG began purchasing in 2009. These emission allowances are held-for-use and are amortized to cost of operations, with NOx allowances amortized on a straight-line basis and SO_2 allowances and RGGI credits amortized based on units of production. During the year ended December 31, 2011, the Company recorded an impairment charge of $160 million on the Company's Acid Rain Program SO_2 emission allowances in order to comply with the Acid Rain Program as discussed in Note 24, Environmental Matters.
- Development rights — Arising primarily from the acquisition of solar businesses in 2010 and 2011, these intangibles are amortizable to depreciation and amortization expense on a straight-line basis over the estimated life of the related project portfolio.
- Energy supply contracts — Established with the acquisitions of Reliant Energy and Green Mountain Energy, these represent the fair value at the acquisition date of in-market contracts for the purchase of energy to serve retail electric customers. The contracts are amortized to cost of operations based on the expected delivery under the respective contracts.
- In-market fuel (gas and nuclear) contracts — These intangibles were established with the Texas Genco acquisition in 2006 and are amortized to cost of operations over expected volumes over the life of each contract.
- Customer contracts — Established with the acquisitions of Reliant Energy, Green Mountain Energy, and Northwind Phoenix, these intangibles represent the fair value at the acquisition date of contracts that primarily provide electricity to Reliant Energy's and Green Mountain Energy's C&I customers. These contracts are amortized to revenues based on expected volumes to be delivered for the portfolio.
- Customer relationships — These intangibles represent the fair value at the acquisition date of acquired businesses' customer base, primarily for Energy Alternatives, Energy Plus, Reliant Energy, Green Mountain Energy, Energy Systems and Energy Curtailment Specialists. The customer relationships are amortized to depreciation and amortization expense based on the expected discounted future net cash flows by year.
- Marketing partnerships — Established with the acquisition of Energy Plus, as further discussed in Note 3, Business Acquisitions and Dispositions, these intangibles represent the fair value at the acquisition date of existing agreements with loyalty and affinity partners. The marketing partnerships are amortized to depreciation and amortization expense based on the expected discounted future net cash flows by year.
- Trade names — Established with the Reliant Energy, Green Mountain and Energy Plus acquisitions, these intangibles are amortized to depreciation and amortization expense, on a straight-line basis.
- Other — Consists of renewable energy credits, wind intangible assets, costs to extend the operating license for STP Units 1 and 2, the intangible asset related to a purchased ground lease and the value of acquired power purchase agreements.

The following tables summarize the components of NRG's intangible assets subject to amortization:

Year Ended December 31, 2013	Emission Allowances	Development Rights	Contracts Energy Supply	Contracts Fuel	Contracts Customer	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
	(In millions)									
January 1, 2013	$793	$ 24	$54	$72	$859	$ 640	$ 88	$318	$68	$2,916
Purchases	76	—	—	—	—	14	—	—	28	118
Acquisition of businesses	—	—	—	—	—	89	—	—	10	99
Usage	—	—	—	—	—	—	—	—	(14)	(14)
Other	2	(5)	—	—	—	—	—	—	1	(2)
December 31, 2013	871	19	54	72	859	743	88	318	93	3,117
Less accumulated amortization	(433)	—	(36)	(61)	(847)	(487)	(12)	(93)	(8)	(1,977)
Net carrying amount	$438	$ 19	$18	$11	$12	$ 256	$ 76	$225	$85	$1,140

Year Ended December 31, 2012	Emission Allowances	Development Rights	Contracts Energy Supply	Contracts Fuel	Contracts Customer	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
	(In millions)									
January 1, 2012	$783	$ 24	$54	$72	$859	$ 634	$ 88	$318	$39	$2,871
Purchases	18	—	—	—	—	—	—	—	18	36
Acquisition of businesses	53	—	—	—	—	6	—	—	10	69
Usage	—	—	—	—	—	—	—	—	(13)	(13)
Sales	(4)	—	—	—	—	—	—	—	—	(4)
Write-off of fully amortized balances	(56)	—	—	—	—	—	—	—	—	(56)
Other	(1)	—	—	—	—	—	—	—	14	13
December 31, 2012	793	24	54	72	859	640	88	318	68	2,916
Less accumulated amortization[(a)]	(329)	—	(30)	(59)	(794)	(415)	(4)	(72)	(3)	(1,706)
Net carrying amount	$464	$ 24	$24	$13	$65	$ 225	$ 84	$246	$65	$1,210

(a) Adjusted for write-off of fully amortized emission allowances of $56 million

The following table presents NRG's amortization of intangible assets for each of the past three years:

Amortization	Years Ended December 31, 2013	2012	2011
	(In millions)		
Emission allowances	$104	$50	$66
Energy supply contracts	6	5	4
Fuel contracts	2	2	2

Customer contracts	53	119	185
Customer relationships	72	98	109
Marketing partnerships	8	4	—
Trade names	29	30	22
Other	5	2	—
Total amortization	$279	$310	$388

The following table presents estimated amortization of NRG's intangible assets for each of the next five years:

Year Ended December 31,	Emission Allowances (In millions)	Development Rights	Contracts Energy Supply	Fuel	Customer	Customer Relationships	Marketing Partnerships	Trade Names	Total
2014	$77	$ 1	$6	$2	$1	$61	$15	$21	$184
2015	65	1	6	2	1	45	14	21	155
2016	64	1	6	2	1	31	9	21	135
2017	65	1	—	—	1	21	5	21	114
2018	68	1	—	—	1	10	5	21	106

The following table presents the weighted average remaining amortization period related to NRG's intangible assets purchased in 2013 business acquisitions:

As of December 31, 2013	Customer Relationships (In years)
Weighted average remaining amortization period	28

Intangible assets held for sale — From time to time, management may authorize the transfer from the Company's emission bank of emission allowances held-for-use to intangible assets held-for-sale. Emission allowances held-for-sale are included in other non current assets on the Company's consolidated balance sheet and are not amortized, but rather expensed as sold. As of December 31, 2013, the value of emission allowances held-for-sale is $24 million and is managed within the Corporate segment. Once transferred to held-for-sale, these emission allowances are prohibited from moving back to held-for-use.

Out-of-market contracts — Due primarily to business acquisitions, NRG acquired certain out-of-market contracts, which are classified as non-current liabilities on NRG's consolidated balance sheet. These include out-of-market lease contracts of $790 million and out-of-market gas transportation and storage contracts of $327 million acquired in the acquisition of GenOn. These out-of-market contracts are amortized to cost of operations. In addition, the power and customer contracts are amortized to revenues, while the energy supply contracts are amortized to cost of operations.

The following table summarizes the estimated amortization related to NRG's out-of-market contracts:

Year Ended December 31,	Power Contracts (In millions)	Leases	Gas Transportation	Total
2014	$17	39	$ 36	$92
2015	17	39	37	93
2016	18	39	42	99
2017	18	39	37	94
2018	19	39	32	90

Note 12 — Debt and Capital Leases

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

	As of December 31,		
	2013	2012	Interest Rate % (a)
	(In millions except rates)		
NRG Recourse Debt:			
Senior notes, due 2018	$1,130	$1,200	7.625
Senior notes, due 2019	800	800	7.625
Senior notes, due 2019	602	693	8.500
Senior notes, due 2020	1,062	1,100	8.250
Senior notes, due 2021	1,128	1,128	7.875
Senior notes, due 2023	990	990	6.625
Term loan facility, due 2018	2,002	1,573	L+3.00/L+2.00
Indian River Power LLC, tax exempt bonds, due 2040 and 2045	247	247	5.375 - 6.00
Dunkirk Power LLC, tax exempt bonds, due 2042	59	59	5.875
Fort Bend County, tax-exempt bonds, due 2038 and 2042	67	28	4.750
Subtotal NRG Recourse Debt	8,087	7,818	
NRG Non-Recourse Debt:			
GenOn senior notes, due 2014	—	617	7.625
GenOn senior notes, due 2017	782	800	7.875
GenOn senior notes, due 2018	780	801	9.500
GenOn senior notes, due 2020	621	631	9.875
GenOn Americas Generation senior notes, due 2021	503	509	8.500
GenOn Americas Generation senior notes, due 2031	435	437	9.125
NRG Marsh Landing term loan, due 2017 and 2023(b)	473	390	L+2.75 - 3.00
CVSR - High Plains Ranch II LLC, due 2014 and 2037(b)	1,104	786	0.611 - 3.579
NRG West Holdings LLC, term loan, due 2023	512	350	L+2.25 - 2.75
Agua Caliente Solar, LLC, due 2037	878	640	2.395 - 3.633
Ivanpah Financing, due 2014 and 2038	1,575	1,437	1.116 - 4.256
South Trent Wind LLC, due 2020	69	72	L+ 2.625
NRG Peaker Finance Co. LLC, bonds, due 2019	154	173	L+1.07
NRG Energy Center Minneapolis LLC, senior secured notes, due 2013, 2017, and 2025(b)	127	137	5.95 - 7.31
NRG Solar Alpine LLC, due 2014 and 2022(b)	221	2	L+2.25 - 2.50
NRG Solar Borrego I LLC, due 2024 and 2038(b)	78	—	L+2.50/5.65
NRG Solar Avra Valley LLC(b)	63	66	L+2.25
TA - High Desert LLC, due 2014, 2023 and 2033	80	—	L+2.50/5.15
NRG Solar Kansas South LLC, due 2014 and 2031	58	—	L+2.00 - 2.625
Other	204	200	various
Subtotal NRG Non-Recourse Debt	8,717	8,048	
Subtotal Long Term Debt	16,804	15,866	
Capital leases:			
Chalk Point capital lease, due 2015	10	14	8.190
Other	3	3	various
Subtotal Capital Leases	13	17	
Subtotal	16,817	15,883	
Less current maturities	1,050	147	
Total long-term debt and capital leases	$15,767	$15,736	

(a) As of December 31, 2013, L+ equals 3 month LIBOR plus x%, with the exception of NRG Solar Alpine LLC cash grant loan and NRG Solar Kansas South LLC and TA - High Desert LLC cash grant bridge loan which are 1 month LIBOR plus x% and NRG Solar Kansas South LLC term loan which is 3 month LIBOR plus x%

(b) Debt related to projects in NRG Yield

Long-term debt includes the following premiums/(discounts):

	As of December 31,	
	2013	2012
	(in millions)	
Senior notes, due 2019	$(5)	$(7)
Term loan facility, due 2018 [(a)]	(5)	(3)
NRG Peaker Finance Co. LLC, bonds, due 2019 [(b)]	(11)	(15)
GenOn senior notes, due 2014 [(c)]	—	42
GenOn senior notes, due 2017 [(c)]	58	75
GenOn senior notes, due 2018 [(c)]	104	126
GenOn senior notes, due 2020 [(c)]	71	81
GenOn Americas Generation senior notes, due 2021 [(c)]	53	59
GenOn Americas Generation senior notes, due 2031 [(c)]	35	37
Total premium/(discount)	$300	$395

(a) Discount of $1 million is related to current maturities in 2013 and 2012.

(b) Discounts of $4 million and $5 million are related to current maturities in 2013 and 2012, respectively.

(c) Premiums for long-term debt acquired in the GenOn acquisition represent adjustments to record the debt at fair value in connection with the acquisition, as described further in Note 3, Business Acquisitions and Dispositions.

NRG Recourse Debt

Senior Notes

Issuance of 2022 Senior Notes

On January 27, 2014, NRG issued $1.1 billion in aggregate principal amount at par of 6.25% senior notes due 2022. The notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest is payable semi-annually beginning on July 15, 2014, until the maturity date of July 15, 2022. The proceeds were utilized to redeem the 8.5% and 7.625% 2019 Senior Notes, as described below, and are also expected to be utilized to fund the acquisition of EME.

In connection with the 2022 Senior Notes, NRG entered into a registration payment arrangement. For the first 90-day period immediately following a registration default, additional interest will be paid in an amount equal to 0.25% per annum of the principal amount of 2022 Senior Notes outstanding, as applicable. The amount of interest paid will increase by an additional 0.25% per annum with respect to each subsequent 90-day period until all registration defaults are cured, up to a maximum amount of interest of 1.0% per annum of the principal amount of the 2022 Senior Notes outstanding, as applicable. The additional interest is paid on the next scheduled interest payment date and following the cure of the registration default, the additional interest payment will cease.

Redemption of 8.5% and 7.625% 2019 Senior Notes

On February 10, 2014, the Company redeemed $308 million of its 8.5% 2019 Senior Notes and $91 million of its 7.625% 2019 Senior Notes through a tender offer and call, at an average early redemption percentage of 106.992% and 105.500%, respectively. A $33 million loss on debt extinguishment of the 8.5% and 7.625% Senior Notes was recorded in the first quarter of 2014, primarily consisting of the premiums paid on the redemption and the write-off of previously deferred financing costs.

Redemption of Senior Notes

In 2012, the Company redeemed its $1.1 billion 2017 Senior Notes through a tender offer and call, at an average early redemption percentage of 104.016%. A $51 million loss on debt extinguishment of the 2017 Senior Notes was recorded, primarily consisting of the premiums paid on the redemption and the write-off of previously deferred financing costs.

In 2011, the Company redeemed its $1.2 billion Senior Notes due 2014 and its $2.4 billion Senior Notes due 2016 at an average redemption percentage of 102.007% and 103.868%, respectively, and recorded a loss on debt extinguishment of $28 million and $115 million, respectively, primarily consisting of the premiums paid on the redemption and the write-off of previously deferred financing costs.

Senior Notes Outstanding

As of December 31, 2013, NRG had six outstanding issuances of senior notes, or Senior Notes, under an Indenture, dated February 2, 2006, or the Indenture, between NRG and Law Debenture Trust Company of New York, as trustee:

(i.)8.500% senior notes, issued June 5, 2009 and due June 15, 2019, or the 2019 Senior Notes;
(ii.)8.250% senior notes, issued August 20, 2010 and due September 1, 2020, or the 2020 Senior Notes;
(iii.)7.625% senior notes, issued January 26, 2011 and due January 15, 2018, or the 2018 Senior Notes;
(iv.)7.625% senior notes, issued May 24, 2011 and due May 15, 2019, or the 7.625% 2019 Senior Notes;
(v.)7.875% senior notes, issued May 24, 2011 and due May 15, 2021, or the 2021 Senior Notes; and
(vi.)6.625% senior notes, issued September 24, 2012 and due March 15, 2023, or the 2023 Senior Notes.

The Company periodically enters into supplemental indentures for the purpose of adding entities under the Senior Notes as guarantors.

The Indentures and the form of notes provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG. The Indentures also provide for customary events of default, which include, among others: nonpayment of principal or interest; breach of other agreements in the Indentures; defaults in failure to pay certain other indebtedness; the rendering of judgments to pay certain amounts of money against NRG and its subsidiaries; the failure of certain guarantees to be enforceable; and certain events of bankruptcy or insolvency. Generally, if an event of default occurs, the Trustee or the Holders of at least 25% in principal amount of the then outstanding series of Senior Notes may declare all of the Senior Notes of such series to be due and payable immediately. The terms of the Indentures, among other things, limit NRG's ability and certain of its subsidiaries' ability to return capital to stockholders, grant liens on assets to lenders and incur additional debt. Interest is payable semi-annually on the Senior Notes until their maturity dates.

Senior Notes Repurchases

On December 17, 2012, NRG entered into an agreement with a financial institution to repurchase up to $200 million of the Senior Notes in the open market by February 27, 2013. In the first quarter of 2013, the Company paid $80 million, $104 million, and $42 million, at an average price of 114.179%, 111.700%, and 113.082% of face value, for repurchases of the Company's 2018 Senior Notes, 2019 Senior Notes and 2020 Senior Notes, respectively. A $28 million loss on the debt extinguishment of the 2018 Senior Notes, 2019 Senior Notes and 2020 Senior Notes was recorded during the three months ended March 31, 2013 which primarily consisted of the premiums paid on the repurchases and the write-off of previously deferred financing costs.

2019 Senior Notes

Prior to June 15, 2014, NRG may redeem all or a portion of the 2019 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 104.25% of the note, plus interest payments due on the note from the date of redemption through June 15, 2014, discounted at a Treasury rate plus 0.50%. In addition, on or after June 15, 2014, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
June 15, 2014 to June 14, 2015	104.250	%
June 15, 2015 to June 14, 2016	102.830	%
June 15, 2016 to June 14, 2017	101.420	%
June 15, 2017 and thereafter	100.000	%

2020 Senior Notes

Prior to September 1, 2015, NRG may redeem all or a portion of the 2020 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of (i) 1% of the principal amount of the note; or (ii) the excess of the principal amount of the note over the following: the present value of 104.125% of the note, plus interest payments due on the note from the date of redemption through September 1, 2015, discounted at a Treasury rate plus 0.50%. In addition, on or after September 1, 2015, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
On or after September 1, 2015	104.125	%
On or after September 1, 2016	102.750	%
On or after September 1, 2017	101.375	%
September 1, 2018 and thereafter	100.000	%

2018 Senior Notes

Prior to maturity, NRG may redeem all or a portion of the 2018 Senior Notes at a redemption price equal to 100% of the principal amount of the notes redeemed plus a premium and accrued and unpaid interest. The premium is the greater of (i) 1% of the principal amount of the note or (ii) the excess of the present value of the principal amount at maturity plus all required interest payments due on the note through the maturity date discounted at a Treasury rate plus 0.50%.

7.625% 2019 Senior Notes

Prior to May 15, 2014, NRG may redeem up to 35% of the aggregate principal amount of the 7.625% 2019 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.625% of the principal amount. Prior to May 15, 2014, NRG may redeem all or a portion of the 7.625% 2019 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.813% of the note, plus interest payments due on the note from the date of redemption through May 15, 2014, discounted at a Treasury rate plus 0.50%. In addition, on or after May 15, 2014, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
May 15, 2014 to May 14, 2015	103.813	%
May 15, 2015 to May 14, 2016	101.906	%
May 15, 2016 and thereafter	100.000	%

2021 Senior Notes

Prior to May 15, 2016, NRG may redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 107.875% of the principal amount. Prior to May 15, 2016, NRG may redeem all or a portion of the 2021 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.938% of the note, plus interest payments due on the note from the date of redemption through May 15, 2016, discounted at a Treasury rate plus 0.50%. In addition, on or after May 15, 2016, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
May 15, 2016 to May 14, 2017	103.938	%
May 15, 2017 to May 14, 2018	102.625	%

May 15, 2018 to May 14, 2019	101.313	%
May 15, 2019 and thereafter	100.000	%

2023 Senior Notes

On September 24, 2012, NRG issued $990 million aggregate principal amount at par of 6.625% Senior Notes due 2023, or the 2023 Senior Notes. The 2023 Senior Notes were issued under the Indenture. The Indenture and the form of the notes provide, among other things, that the 2023 Senior Notes will be senior unsecured obligations of NRG. The proceeds, net of issuance costs, of $978 million for the 2023 Senior Notes were used to complete the tender offer of the 2017 Senior Notes.

Prior to September 15, 2015, NRG may redeem up to 35% of the aggregate principal amount of the 2023 Senior Notes with the net proceeds of certain equity offerings, at a redemption price of 106.625% of the principal amount. Prior to September 15, 2017, NRG may redeem all or a portion of the 2023 Senior Notes at a price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.313% of the note, plus interest payments due on the note from the date of redemption through September 15, 2017, discounted at a Treasury rate plus 0.50%. In addition, on or after September 15, 2017, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
September 15, 2017 to September 14, 2018	103.313	%
September 15, 2018 to September 14, 2019	102.208	%
September 15, 2019 to September 14, 2020	101.104	%
September 15, 2020 and thereafter	100.000	%

In connection with the 2023 Senior Notes, NRG entered into a registration payment arrangement. For the first 90-day period immediately following a registration default, additional interest will be paid in an amount equal to 0.25% per annum of the principal amount of 2023 Senior Notes outstanding, as applicable. The amount of interest paid will increase by an additional 0.25% per annum with respect to each subsequent 90-day period until all registration defaults are cured, up to a maximum amount of interest of 1.0% per annum of the principal amount of the 2023 Senior Notes outstanding, as applicable. The additional interest is paid on the next scheduled interest payment date and following the cure of the registration default, the additional interest payment will cease.

Senior Credit Facility

On June 4, 2013, NRG amended the Term Loan Facility to (i) obtain additional financing of $450 million, which was issued at a discount of 99.5%; and (ii) adjust the interest rate from LIBOR plus 2.50% to LIBOR plus 2.00%. In addition, the Company redeemed and re-issued $407 million of the Term Loan Facility to new lenders resulting in a $7 million loss on debt extinguishment, recorded during the second quarter 2013, which primarily consisted of the write-off of previously deferred financing costs and unamortized discount. The proceeds from the additional $450 million borrowed were used for general corporate purposes. Debt issuance costs of $23 million and a discount on debt issuance of $4 million will be amortized to interest expense through the maturity date of the Term Loan Facility. Repayments under the Term Loan Facility will consist of 0.25% per quarter, with the remainder due at maturity.

The Company also amended the Revolving Credit Facility to (i) increase the capacity by $211 million to a total of $2.5 billion; (ii) adjust the interest rate to LIBOR plus 2.25%; and (iii) extend the maturity date to July 1, 2018 to coincide with the maturity date of the Term Loan Facility. As a result of the amended Revolving Credit Facility, the Company capitalized debt issuance costs of $4 million, which will be amortized to interest expense through the maturity date of the Revolving Credit Facility. A $3 million loss on debt extinguishment was recorded during the three months ended June 30, 2013 related to the write-off of previously deferred financing costs. As of December 31, 2013, a total of $1.3 billion letters of credit were issued under the Revolving Credit Facility, with $1.2 billion remaining available to be issued. Commitment fees of 0.50% are charged on the unused portion of the Revolving Credit Facility.

The Senior Credit Facility replaced an existing senior credit facility in 2011, and NRG recorded a $32 million loss on extinguishment, which consisted of the write-off of previously deferred financing costs.

The Senior Credit Facility is guaranteed by substantially all of NRG's existing and future direct and indirect subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries, and certain other subsidiaries, including GenOn and its subsidiaries. The capital stock of these guarantor subsidiaries has been pledged for the benefit of the Senior Credit Facility's lenders.

The Senior Credit Facility is also secured by first-priority perfected security interests in substantially all of the property and assets owned or acquired by NRG and its subsidiaries, other than certain limited exceptions. These exceptions include assets of certain unrestricted subsidiaries, equity interests in certain of NRG's affiliates that have non-recourse debt financing, including GenOn and its subsidiaries, and voting equity interests in excess of 66% of the total outstanding voting equity interest of certain of NRG's foreign subsidiaries.
The Senior Credit Facility contains customary covenants, which, among other things, require NRG to meet certain financial tests, including minimum interest coverage ratio and a maximum leverage ratio on a consolidated basis, and limit NRG's ability to:

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments, loans and advances; and
- return capital to stockholders.

Interest Rate Swaps — NRG entered into interest rate swaps, which became effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. The Company pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the monthly equivalent of a floating interest payment based on a 1 month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparty are made monthly and the LIBOR is determined in advance of each interest period. The total notional amount of the swaps, which matured on February 1, 2013, was $900 million with changes in the fair value through June 30, 2011 recorded in OCI and subsequent changes in the fair value reported in interest expense.
Fort Bend County Tax Exempt Bonds
On May 3, 2012, NRG executed a $54 million tax-exempt bond financing with a maturity date of May 1, 2038, issued by the Fort Bend County Industrial Development Corporation, or the Fort Bend County Tranche A Bonds. The Fort Bend County Tranche A Bonds will be used for the construction of a peaking unit with one or more components of a carbon capture system at the W.A. Parish Generating Station in Thompsons, TX, or W.A. Parish. The bonds initially bore weekly interest based on the SIFMA rate, and were enhanced by a letter of credit under the Company's Revolving Credit Facility covering amounts drawn. On October 18, 2012, NRG fixed the rate on the Fort Bend County Tranche A Bonds at 4.75% payable semiannually, and the letter of credit was canceled and replaced with an NRG guarantee. As of December 31, 2013 the full $54 million was drawn.
On October 18, 2012, NRG executed an additional $73 million tax-exempt bond financing, with a maturity date of November 1, 2042, also issued by the Fort Bend County Industrial Development Corporation, or the Fort Bend County Tranche B Bonds. The Fort Bend County Tranche B Bonds will be used for environmental and maintenance upgrades at W.A. Parish. The bonds were issued at a fixed rate of 4.75% payable semiannually, and are supported by an NRG guarantee. The proceeds drawn through December 31, 2013 were $12 million and the remaining balance will be drawn over time as qualifying expenditures are paid.
NRG Non-Recourse Debt
The following are descriptions of certain indebtedness of NRG's subsidiaries that are outstanding as of December 31, 2013. All of NRG's non-recourse debt is secured by the assets in the respective GenOn subsidiaries and project subsidiaries as further described below. The net assets in the GenOn and project subsidiaries are subject to restrictions, including the ability to transfer assets out of the subsidiaries. As of December 31, 2013, NRG had net assets of $3.2 billion that were deemed restricted for purposes of Rule 4-08(e)(3)(iii) of Regulation S-X.
The indebtedness described below is non-recourse to NRG, unless otherwise noted.
GenOn Senior Notes
Under the GenOn Senior Notes and the related indentures, the GenOn Senior Notes are the sole obligation of GenOn and are not guaranteed by any subsidiary or affiliate of GenOn. The GenOn Senior Notes are senior unsecured obligations of GenOn having no recourse to any subsidiary or affiliate of GenOn. The GenOn Senior Notes restrict the ability of GenOn and its subsidiaries to encumber their assets. The GenOn Senior Notes are subject to acceleration of GenOn's obligations thereunder upon the occurrence of certain events of default, including: (a) default in interest payment for 30 days, (b) default in the payment of principal or premium, if any, (c) failure after 90 days of specified notice to comply with any other agreements in the indenture, (d) certain cross-acceleration events, (e) failure by GenOn or its significant subsidiaries to pay certain final and non-appealable judgments after 90 days and (f) certain

events of bankruptcy and insolvency.

Redemption of 2014 GenOn Senior Notes

In June 2013, the Company redeemed all of the 2014 GenOn Senior Notes with an aggregate outstanding principal amount of $575 million at a redemption price of 106.778% of face value as well as any accrued and unpaid interest as of the redemption date. In connection with the redemption, an $11 million loss on the debt extinguishment of the 2014 GenOn Senior Notes was recorded during the three months ended June 30, 2013 which primarily consisted of a make whole premium payment offset by the write-off of unamortized premium.

The GenOn Senior Notes due 2014, which had a face value of $575 million, were recorded at their fair value of $618 million on the GenOn acquisition date. The related $43 million premium was being amortized to interest expense until the notes were redeemed in June 2013, as previously discussed.

2018 and 2020 GenOn Senior Notes

The GenOn Senior Notes due 2018 and 2020 and the related indentures restrict the ability of GenOn to incur additional liens and make certain restricted payments, including dividends. In the event of a default or if restricted payment tests are not satisfied, GenOn would not be able to distribute cash to its parent, NRG. At December 31, 2013, GenOn did not meet the consolidated debt ratio component of the restricted payments test and, therefore, the ability of GenOn to make restricted payments, including dividends, loans and advances to NRG, is limited to specified exclusions, including up to $250 million of such restricted payments. As of December 31, 2013, GenOn net assets of $0 billion were deemed restricted for purposes of Rule 4-08(e)(3)(iii) of Regulation S-X.

Prior to maturity, GenOn may redeem the senior notes due 2018, in whole or in part, at a redemption price equal to 100% of the principal amount plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the following: the present value of 100% of the note, plus interest payments due on the note through maturity, discounted at a Treasury rate plus 0.50% over the principal amount of the note.

Prior to October 15, 2015, GenOn may redeem the senior notes due 2020, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the following: the present value of 100% of the note, plus interest payments due on the note through maturity, discounted at a Treasury rate plus 0.50% over the principal amount of the note. In addition, on or after October 15, 2015, GenOn may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption rate:

Redemption Period	Redemption Percentage	
October 15, 2015 to October 14, 2016	104.938	%
October 15, 2016 to October 14, 2017	103.292	%
October 15, 2017 to October 14, 2018	101.646	%
October 15, 2018 and thereafter	100.000	%

The GenOn Senior Notes due 2018 and 2020, which have a face value of $675 million and $550 million, respectively, were recorded at their fair values of $802 million and $632 million, respectively, on the GenOn acquisition date. The $127 million and $82 million premiums are being amortized to interest expense over the life of the related notes.

2017 GenOn Senior Notes

Prior to maturity, GenOn may redeem all or a part of the GenOn Senior Notes due 2017 at a redemption price equal to 100% of the notes plus a premium and accrued and unpaid interest. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the following: the present value of 100% of the note, plus interest payments due on the note through maturity, discounted at a Treasury rate plus 0.50% over the principal amount of the note.

The GenOn Senior Notes due 2017, which have a face value of $725 million, were recorded at their fair value of $800 million, on the GenOn acquisition date. The $75 million premium is being amortized to interest expense over the life of the notes.

GenOn Americas Generation Senior Notes

The GenOn Americas Generation Senior Notes due 2021 and 2031 are senior unsecured obligations of GenOn Americas Generation, a wholly owned subsidiary of NRG, having no recourse to any subsidiary or affiliate of GenOn Americas Generation.

Prior to maturity, GenOn Americas Generation may redeem all or a part of the senior notes due 2021 and 2031 at a redemption price equal to 100% of the notes plus a premium and accrued and unpaid interest. The premium is the greater of: (i) the discounted present value of the then-remaining scheduled payments of principal and interest on the outstanding notes, discounted at a Treasury rate plus 0.375%, less the unpaid principal amount; and (ii) zero.

The GenOn Americas Generation Senior Notes, which have a face value of $450 million and $400 million, respectively, were recorded at their fair values of $510 million and $437 million, respectively, on the GenOn acquisition date. The $60 million and $37 million premiums are being amortized to interest expense over the life of the related notes.

NRG Yield, Inc. Convertible Notes

On February 11, 2014, NRG Yield, Inc. closed on its offering of $300 million aggregate principal amount of 3.50% Convertible Senior Notes due 2019, or the NRG Yield Senior Notes. The initial purchasers exercised their option to purchase up to an additional $45 million in aggregate principal amount of the NRG Yield Senior Notes. NRG Yield, Inc. expects to receive the proceeds in early March. The NRG Yield Senior Notes are convertible, under certain circumstances, into NRG Yield, Inc. common stock, cash or a combination thereof at an initial conversion price of $46.55 per Class A common share, which is equivalent to an initial conversion rate of approximately 21.4822 shares of Class A common stock per $1,000 principal amount of NRG Yield Senior Notes. Interest on the NRG Yield Senior Notes is payable semi-annually in arrears on February 1 and August 1 of each year, commencing on August 1, 2014. The NRG Yield Senior Notes will mature on February 1, 2019, unless earlier repurchased or converted in accordance with their terms. Prior to the close of business on the business day immediately preceding August 1, 2018, the NRG Yield Senior Notes will be convertible only upon the occurrence of certain events and during certain periods, and thereafter, at any time until the close of business on the second scheduled trading day immediately preceding the maturity date.

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that are outstanding as of December 31, 2013.

Dandan Financing

In December 2013, with respect to the Guam solar project, NRG, through its wholly-owned subsidiary, NRG Solar Dandan LLC, or Dandan, entered into a credit agreement with a bank, or the Dandan Financing Agreement, for a $81 million construction loan that converts to a term loan in September 2014 and a $23 million cash grant loan. The construction loans have interest rates of LIBOR plus an applicable margin of 2.25% or base rate plus 1.25% and the cash grant loans have an interest rate of LIBOR plus an applicable margin of 1.75%. The term loan has an interest rate of LIBOR plus an applicable margin of 2.25%, which escalates 0.25% on the fifth, tenth, and fifteenth anniversary of the term conversion. The term loan, which is secured by all the assets of Dandan, matures on the 18th anniversary of the term conversion and amortizes based upon a predetermined schedule. The Dandan Financing Agreement also includes a letter of credit facility on behalf of Dandan of up to $5 million. Dandan pays an availability fee of 2.25% from the closing date until the 5th anniversary of the term conversion date and 2.50% from the 5th anniversary of the term conversion date on issued letters of credit. As of December 31, 2013, $19 million was outstanding under the term loan, and $5 million in letters of credit in support of the project were issued.

Kansas South Facility

In the second quarter of 2013, the Company, through its wholly owned subsidiary, NRG Solar PV LLC, acquired Kansas South, a 20 MW utility-scale photovoltaic solar facility located in Kings County, California, shortly before commercial operation. In June 2013, NRG recorded $59 million of non-recourse project level debt under the Kansas South Facility which includes a $38 million term loan due 2031 and a $21 million cash grant bridge loan due the earlier of 10 days after receipt of the cash grant or March 2014. The term loan has an interest rate of 3 month LIBOR plus an applicable margin of 2.625% and increases by 0.25% every four years. The cash grant bridge loan has an interest rate of 1 month LIBOR plus an applicable margin of 2.00%. The term loan amortizes on a predetermined schedule and is secured by all of the assets of Kansas South. As of December 31, 2013, $4 million of letters of credit were issued under the Kansas South Facility.

NRG Repowering Holdings LLC Facility

In June 2013, $82 million of letters of credit issued under the NRG Repowering Holdings LLC Facility were returned to the Company. In July 2013, the NRG Repowering Holding LLC Facility was terminated and the Company issued replacement letters of credit under its Revolving Credit Facility.

Marsh Landing Credit Agreement

In October 2010, Marsh Landing entered into a credit agreement for up to approximately $650 million of commitments to provide construction and permanent financing for the Marsh Landing generating facility. The credit facility consisted of a $155 million tranche A senior secured term loan facility, due 2017, a $345 million tranche B senior secured term loan facility, due 2023, a $50 million senior secured letter of credit facility to support debt service reserve requirements and a $100 million senior secured letter of credit facility to support collateral requirements under its PPA with PG&E. In May 2013, Marsh Landing met the conditions under the credit agreement to convert the construction loan for the facility to a term loan, which will amortize on a predetermined basis. Prior to term conversion, the Company drew the remaining funds available under the facility in order to pay costs due for construction. The Company issued a $24 million letter of credit under the facility in support of its debt service requirements. As of December 31, 2013, Marsh Landing had $473 million outstanding.

Avra Valley Financing

On August 30, 2012, NRG, through its subsidiary, NRG Solar Avra Valley LLC, or Avra Valley, entered into a credit agreement with a bank, or the Avra Valley Financing Agreement, for a $66 million construction loan that converted to a term loan in January 2013 and an $8 million cash grant loan. Both the construction and cash grant loans have interest rates of LIBOR plus an applicable margin of 2.25%. The term loan has an interest rate of LIBOR plus an applicable margin of 2.25%, which escalates 0.25% on the fifth, tenth, and fifteenth anniversary of the term conversion. The term loan, which is secured by all the assets of Avra Valley, matures on the 18th anniversary of the term conversion and amortizes based upon a predetermined schedule. The cash grant was received and the cash grant loan was repaid in June 2013. The Avra Valley Financing Agreement also includes a letter of credit facility on behalf of Avra Valley of up to $4 million. Avra Valley pays an availability fee of 100% of the applicable margin on issued letters of credit. As of December 31, 2013, $63 million was outstanding under the term loan, and $4 million in letters of credit in support of the project were issued.

Alpine Financing

On March 16, 2012, NRG, through its wholly-owned subsidiary, NRG Solar Alpine LLC, or Alpine, entered into a credit agreement with a group of lenders, or the Alpine Financing Agreement, for a $166 million construction loan, which converted to a term loan in March 2013, and a $68 million cash grant loan. On January 15, 2013 the credit agreement was amended reducing the cash grant loan to $63 million. The construction loan had an interest rate of LIBOR plus an applicable margin of 2.50% and the cash grant loan has an interest rate of 1 month LIBOR plus an applicable margin of 2.25%. The term loan has an interest rate of LIBOR plus an applicable margin of 2.50%, which escalates 0.25% on the fifth anniversary of the term conversion. The term loan, which is secured by all the assets of Alpine, amortizes based upon a predetermined schedule with final maturity in November 2022. The Alpine Financing Agreement also includes a letter of credit facility on behalf of Alpine of up to $37 million. Alpine pays an availability fee of 100% of the applicable margin on issued letters of credit. As of December 31, 2013, $159 million was outstanding under the term loans, and $37 million in letters of credit in support of the project were issued. In January, 2014, the Company was awarded the full cash grant of $72 million as applied for, relating to the Alpine project, and has received the post-sequestration funds of $66 million, and subsequently repaid the balance of the cash grant loan.

High Desert Facility

In the first quarter of 2013, the Company, through its wholly owned subsidiary, NRG Solar PV LLC, acquired High Desert, a 20 MW utility-scale photovoltaic solar facility located in Lancaster, California, shortly before commercial operation. As part of the acquisition of High Desert, NRG recorded $82 million of non-recourse project level debt in March 2013 issued under the High Desert Facility which is comprised of $53 million of fixed rate notes due 2033 at an interest rate of 5.15%, $7 million of floating rate notes due 2023, $22 million of bridge notes due the earlier of 10 days after receipt of the cash grant or May 2014 and a revolving facility of $12 million. The floating rate notes have an interest rate of 3 month LIBOR while the bridge notes have an interest rate of 1 month LIBOR plus 2.50%. The revolving facility can be used for cash or for the issuance of up to $9 million in letters of credit. As of December 31, 2013, $9 million of letters of credit were issued under the revolving facility. The notes amortize on predetermined schedules and are secured by all of the assets of High Desert.

NRG Yield Revolving Credit Facility

In connection with the initial public offering of Class A common stock of NRG Yield, Inc. in July 2013, as further described in Note 1, Nature of Business, NRG Yield LLC and its direct wholly owned subsidiary, NRG Yield Operating LLC, entered into a senior secured revolving credit facility, which provides a revolving line of credit of $60 million. The NRG Yield revolving credit facility can be used for cash or for the issuance of letters of credit. There was no cash drawn or letters of credit issued under the NRG Yield revolving credit facility as of December 31, 2013.

CVSR Financing

On September 30, 2011, NRG acquired CVSR, as discussed in Note 3, Business Acquisitions and Dispositions. In connection with the acquisition, High Plains Ranch II LLC, a wholly-owned subsidiary of NRG, entered into the CVSR Financing Agreement with the FFB, to borrow up to $1.2 billion to finance the costs of constructing this solar facility. The CVSR Financing Agreement, which matures in 2037, is non-recourse to NRG. Funding requests will be submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the CVSR Financing Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375%, and are secured by the assets of CVSR. As of December 31, 2013, $1,104 million was outstanding under the loan.

In January 2014, the U.S. Treasury Department awarded the Company cash grants for the CVSR project of $307 million, or $285 million net of sequestration, which was approximately 75% of the cash grant for which the Company had applied. NRG is evaluating the basis for the award and all of its options with respect to recovering the full amount of the award. Proceeds received in January 2014 were utilized to repay the borrowings due on February 5, 2014.

Under the terms of the CVSR Financing Agreement, on November 17, 2011, CVSR entered into a series of swaptions with a notional value of $686 million, or 80% of the guaranteed term loan amount, in order to hedge the project interest rate risk. These swaptions matured over a series of seven scheduled settlement dates to correspond with the completion dates of the project. As of December 31, 2013, all of the swaptions have expired.

NRG West Holdings Credit Agreement

On August 23, 2011, NRG, through its wholly-owned subsidiary, NRG West Holdings LLC, or West Holdings, entered into a credit agreement with a group of lenders in respect to the El Segundo Energy Center, or the West Holdings Credit Agreement. The West Holdings Credit Agreement, which establishes a $540 million, two tranche construction loan facility with additional facilities for the issuance of letters of credit or working capital loans, is secured by the assets of West Holdings.

The two tranche construction loan facility consists of the $480 million Tranche A Construction Facility, or the Tranche A Facility, and the $60 million Tranche B Construction Facility, or the Tranche B Facility. The Tranche A and Tranche B Facilities, which mature in August 2023, convert to a term loan and have an interest rate of LIBOR, plus an applicable margin which increases by 0.125% periodically from conversion through year eight for the Tranche A Facility and increases by 0.125% upon term conversion and on the third and sixth anniversary of the term conversion and by 0.250% on the eighth anniversary of the term conversion for the Tranche B Facility. The Tranche A and Tranche B Facilities amortize based upon a predetermined schedule over the term of the loan with the balance payable at maturity.

The West Holdings Credit Agreement also provides for the issuance of letters of credit and working capital loans to support the El Segundo Energy Center collateral needs. This includes letter of credit facilities on behalf of West Holdings of up to $90 million in support of the PPA, up to $48 million in support of the collateral agent, and a working capital facility which permits loans or the issuance of letters of credit of up to $10 million.

As of December 31, 2013, under the West Holdings Credit Agreement, West Holdings borrowed $480 million under the Tranche A Facility, $32 million under the Tranche B Facility, issued a $33 million letter of credit in support of the PPA, and issued a $1 million letter of credit under the working capital facility.

Agua Caliente Financing

On August 5, 2011, NRG acquired Agua Caliente, as discussed in Note 3, Business Acquisitions and Dispositions. In connection with the acquisition, Agua Caliente Solar LLC, a wholly-owned subsidiary of NRG, entered into the Agua Caliente Financing Agreement with the FFB, to borrow up to $967 million to finance the costs of constructing this solar facility. The Agua Caliente Financing Agreement, which matures in 2037, is non-recourse to NRG. Funding requests will be submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the Agua Caliente Financing Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375%, and are secured by the assets of Agua Caliente. As of December 31, 2013, $878 million had been drawn under this agreement.

Ivanpah Financing

On April 5, 2011, NRG acquired a majority interest in Ivanpah, as discussed in Note 3, Business Acquisitions and Dispositions. On April 5, 2011, Ivanpah entered into the Ivanpah Credit Agreement with the FFB to borrow up to $1.6 billion to finance the costs of constructing the Ivanpah solar facilities. Each phase of the project is governed by a separate financing agreement and is non-recourse to both the other projects and to NRG. Funding requests are submitted to the FFB on a monthly basis and the loans provided by the FFB are guaranteed by the U.S. DOE. Amounts borrowed under the Ivanpah Credit Agreement accrue interest at a fixed rate based on U.S. Treasury rates plus a spread of 0.375% and are secured by all the assets of Ivanpah. On February 27, 2014, Solar Partners II received an extension with respect to its borrowings previously due in 2014, which are subsequently due in 2015. Solar Partners II intends to submit an application to the U.S. Department of Treasury for a cash grant; any proceeds received will be utilized to repay the borrowings that mature in 2015.

The following table reflects the borrowings under the Ivanpah Credit Agreement as of December 31, 2013:

	Maximum borrowings available under Ivanpah Credit Agreement	Amounts borrowed	Weighted average interest rate on amounts borrowed	
	(In millions, except rates)			
Solar Partners I, due June 27, 2014 [(a)]	$159	$159	1.680	%
Solar Partners I, due June 27, 2033	392	371	2.808	%
Solar Partners II, due February 27, 2014 [(a)]	132	132	1.611	%
Solar Partners II, due February 27, 2038	387	377	3.132	%
Solar Partners VIII, due October 27, 2014 [(a)]	117	116	1.998	%
Solar Partners VIII, due October 27, 2038	440	420	3.097	%
	$1,627	$1,575		

(a) The cash portion of the loan is fully drawn; additional amounts will be utilized for capitalized interest.

Peakers

In June 2002, NRG Peaker Finance Company LLC, or Peakers, an indirect wholly-owned subsidiary of NRG, issued $325 million in floating rate bonds due June 2019. Peakers subsequently swapped such floating rate debt for fixed rate debt at an all-in cost of 6.67% per annum. Principal, interest, and swap payments were originally guaranteed by Syncora Guarantee Inc., successor in interest to XL Capital Assurance, through a financial guaranty insurance policy. In 2009, Assured Guaranty Mutual Corp assumed the responsibility as the bond insurer and controlling party. Syncora Guarantee Inc. continues to be the swap insurer. These notes are also secured by, among other things, substantially all of the assets of and membership interests in Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, NRG Rockford LLC, NRG Rockford II LLC, and NRG Rockford Equipment LLC. As of December 31, 2013, $165 million in principal remained outstanding on these bonds. Upon emergence from bankruptcy, NRG issued a $36 million letter of credit to Peakers' collateral agent. The letter of credit may be drawn if the project is unable to meet principal or interest payments. There are no provisions requiring NRG to replenish the letter of credit if it is drawn. On December 10, 2012, the collateral agent drew the remaining $4 million on the letter of credit, and NRG contributed $19 million in equity to Peakers to meet its debt service requirements. On December 10, 2013, NRG contributed an additional $32 million in equity to Peakers to meet its debt service requirements. As of December 31, 2013, nothing remains available for additional letters of credit issuances.

On February 21, 2014, NRG Peaker Finance Company LLC elected to redeem approximately $30 million of the outstanding bonds at a redemption price equal to the principal amount plus a redemption premium, accrued and unpaid interest, and other fees, totaling approximately $35 million in connection with the removal of Bayou Cove Peaking Power LLC from the peaker financing collateral package, which also involved limited commitments for certain repairs on other assets that were funded concurrently with the making of the December 10, 2013 debt service payment. The removal of Bayou Cove Peaking Power LLC from the collateral package provides the Company flexibility on future transactions with respect to this asset.

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Interest Rate Swaps — Project Financings

Many of NRG's project subsidiaries entered into interest rate swaps, intended to hedge the risks associated with interest rates on non-recourse project level debt. These swaps amortize in proportion to their respective loans and are floating for fixed where the project subsidiary pays its counterparty the equivalent of a fixed interest payment on a predetermined notional value and will receive quarterly the equivalent of a floating interest payment based on the same notional value. All interest rate swap payments by the project subsidiary and its counterparty are made quarterly and the LIBOR is determined in advance of each interest period. The following table summarizes the swaps, some of which are forward starting as indicated, related to NRG's project level debt as of December 31, 2013.

Non-Recourse Debt	% of Principal		Fixed Interest Rate		Floating Interest Rate	Notional Amount at December 31, 2013 (In millions)	Effective Date	Maturity Date
NRG Peaker Finance Co. LLC	100	%	6.673	%	3-mo. LIBOR + 1.07%	$165	June 18, 2002	June 10, 2019
NRG West Holdings LLC	75	%	2.417	%	3-mo. LIBOR	405	November 30, 2011	August 31, 2023
South Trent Wind LLC	75	%	3.265	%	3-mo. LIBOR	51	June 15, 2010	June 14, 2020
South Trent Wind LLC	75	%	4.95	%	3-mo. LIBOR	21	June 30, 2020	June 14, 2028
NRG Solar Roadrunner LLC	75	%	4.313	%	3-mo. LIBOR	33	September 30, 2011	December 31, 2029
NRG Solar Alpine LLC	85	%	2.744	%	3-mo. LIBOR	135	December 31, 2012	December 31, 2029
NRG Solar Avra Valley LLC	90	%	2.333	%	3-mo. LIBOR	56	November 30, 2012	November 30, 2030
NRG Marsh Landing	75	%	3.244	%	3-mo. LIBOR	472	June 28, 2013	June 30, 2023
Other	75	%	various		various	104	various	various

Consolidated Annual Maturities

Annual payments based on the maturities of NRG's debt, for the years ending after December 31, 2013, are as follows:

	(In millions)
2014	$1,045
2015	254
2016	270
2017	1,034
2018	4,035
Thereafter	10,166
Total	$16,804

Note 13 — Asset Retirement Obligations

NRG's AROs are primarily related to the future dismantlement of equipment on leased property and environmental obligations related to nuclear decommissioning, ash disposal, site closures, and fuel storage facilities. In addition, NRG has also identified conditional AROs for asbestos removal and disposal, which are specific to certain power generation operations.

See Note 6, Nuclear Decommissioning Trust Fund, for a further discussion of NRG's nuclear decommissioning obligations. Accretion for the nuclear decommissioning ARO and amortization of the related ARO asset are recorded to the Nuclear Decommissioning Trust Liability to the ratepayers and are not included in net income, consistent with regulatory treatment.

The following table represents the balance of ARO obligations as of December 31, 2013, and 2012, along with the additions, reductions and accretion related to the Company's ARO obligations for the year ended December 31, 2013:

(In millions)

Balance as of December 31, 2012	$646
Revisions in estimates for current obligations	(77)
Additions	29
Spending for current obligations	(5)
Accretion — Expense	19
Accretion — Nuclear decommissioning	17
Balance as of December 31, 2013	$629

Note 14 — Benefit Plans and Other Postretirement Benefits

NRG sponsors and operates defined benefit pension and other postretirement plans. As part of the GenOn acquisition, discussed in Note 3, Business Acquisitions and Dispositions, NRG assumed GenOn's defined benefit pension plans and other postretirement benefit plans, and GenOn's benefit plan obligations were recorded at fair value at the time of the acquisition. NRG expects to contribute $78 million to the Company's pension plans in 2014.

NRG pension benefits are available to eligible non-union and union employees through various defined benefit pension plans. These benefits are based on pay, service history and age at retirement. Most pension benefits are provided through tax-qualified plans. Certain executive pension benefits that cannot be provided by the tax-qualified plans are provided through unfunded non-tax-qualified plans. NRG also provides postretirement health and welfare benefits for certain groups of employees. Cost sharing provisions vary by the terms of any applicable collective bargaining agreements.

As part of the change in control associated with the GenOn acquisition, NRG has decided to terminate/settle the nonqualified legacy GenOn Benefit Restoration Plan and Supplemental Executive Retirement Plan. Final settlement payments totaling $12 million will be paid to remaining participants in the first quarter of 2014.

NRG Defined Benefit Plans

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

	Year Ended December 31,		
	Pension Benefits		
	2013	2012	2011
	(In millions)		
Service cost benefits earned	$30	$14	$14
Interest cost on benefit obligation	47	23	21
Expected return on plan assets	(55)	(23)	(21)
Amortization of unrecognized net loss	9	4	—
Curtailment	(1)	—	—
Net periodic benefit cost	$30	$18	$14

	Year Ended December 31,		
	Other Postretirement Benefits		
	2013	2012	2011
	(In millions)		
Service cost benefits earned	$4	$2	$2
Interest cost on benefit obligation	9	6	6
Amortization of unrecognized net loss	—	1	—
Net periodic benefit cost	$13	$9	$8

A comparison of the pension benefit obligation, other postretirement benefit obligations and related plan assets for NRG's plans on a combined basis is as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(In millions)			
Benefit obligation at January 1	$1,147	$456	$220	$122
Obligations assumed in the GenOn acquisition	—	596	—	87
Service cost	30	14	4	2
Interest cost	47	23	9	6
Plan amendments	5	—	(4)	(1)
Actuarial (gain)/loss	(125)	75	(29)	6
Employee and retiree contributions	—	—	2	1
Benefit payments	(43)	(17)	(11)	(3)
Curtailment	(1)	—	—	—
Benefit obligation at December 31	1,060	1,147	191	220
Fair value of plan assets at January 1	757	308	—	—
Assets acquired in the GenOn acquisition	—	402	—	—
Actual return on plan assets	116	41	—	—
Employee contributions	—	—	2	1
Employer contributions	50	23	9	2
Benefit payments	(43)	(17)	(11)	(3)
Fair value of plan assets at December 31	880	757	—	—
Funded status at December 31 — excess of obligation over assets	$(180)	$(390)	$(191)	$(220)

Amounts recognized in NRG's balance sheets were as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(In millions)			
Current liabilities	$12	$1	$9	$9
Non-current liabilities	166	389	182	211

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

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(In millions)			
Unrecognized (gain)/loss	$(57)	$140	$(12)	$17
Prior service cost/(credit)	4	(2)	(6)	(2)

Other changes in plan assets and benefit obligations recognized in OCI were as follows:

	Year Ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(In millions)			
Unrecognized (gain)/loss	$(188)	$56	$(29)	$7
Amortization of net actuarial gain	(9)	(4)	—	(1)
Prior service credit	5	—	(4)	(1)
Curtailment	1	—	—	—
Total recognized in other comprehensive loss	$(191)	$52	$(33)	$5
Total recognized in net periodic pension cost and other comprehensive income	$(161)	$71	$(20)	$13

The Company's estimated unrecognized gain and unrecognized prior service cost for NRG's pension plan that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is approximately $5 million. The Company's estimated unrecognized gain and unrecognized prior service cost for NRG's postretirement plan that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is $2 million.

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

	As of December 31,	
	Pension Benefits	
	2013	2012
	(In millions)	
Projected benefit obligation	$1,060	$1,147
Accumulated benefit obligation	967	1,024
Fair value of plan assets	880	757

NRG's market-related value of its plan assets is the fair value of the assets. The fair values of the Company's pension plan assets by asset category and their level within the fair value hierarchy are as follows:

	Fair Value Measurements as of December 31, 2013		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
	(In millions)		
Common/collective trust investment — U.S. equity	—	370	370
Common/collective trust investment — non-U.S. equity	—	212	212
Common/collective trust investment — fixed income	—	296	296
Short-term investment fund	2	—	2
Total	$2	$ 878	$880

	Fair Value Measurements as of December 31, 2012		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
	(In millions)		
U.S. equity investment	$—	$ 26	$26
Non-U.S. equity investment	24	44	68
Corporate bond investment — fixed income	—	32	32

Common/collective trust investment — U.S. equity	—	290	290
Common/collective trust investment — non-U.S. equity	—	111	111
Common/collective trust investment — fixed income	—	228	228
Short-term investment fund	—	2	2
Total	$24	$ 733	$757

In accordance with ASC 820, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the U.S. and non-U.S. equity investments and the corporate bond investment is based on quoted prices in active markets, and is categorized as Level 1. All equity investments are valued at the net asset value of shares held at year end. The fair value of the corporate bond investment is based on the closing price reported on the active market on which the individual securities are traded. The fair value of the common/collective trusts is valued at fair value which is equal to the sum of the market value of all of the fund's underlying investments, and is categorized as Level 2. There are no investments categorized as Level 3.

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

	As of December 31,							
	Pension Benefits				Other Postretirement Benefits			
Weighted-Average Assumptions	2013		2012		2013		2012	
Discount rate	4.99	%	4.16	%	5.06	%	4.31	%
Rate of compensation increase	3.65	%	3.57	%	N/A		N/A	
Health care trend rate	—		—		8.5% grading to 5.5% in 2019		8.0% grading to 5.0% in 2019	

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

	As of December 31,											
	Pension Benefits						Other Postretirement Benefits					
Weighted-Average Assumptions	2013		2012		2011		2013		2012		2011	
Discount rate	4.16	%	4.95	%	5.47	%	4.31	%	5.15	%	5.77	%
Expected return on plan assets	7.12	%	6.96	%	7.34	%	—		—		—	
Rate of compensation increase	3.57	%	4.34	%	4.4	%	—		—		—	
Health care trend rate	—		—		—		8.3% grading to 5.3% in 2019		8.0% grading to 5.0% in 2019		8.0% grading to 5.0% in 2019	

NRG uses December 31 of each respective year as the measurement date for the Company's pension and other postretirement benefit plans. The Company sets the discount rate assumptions on an annual basis for each of NRG's retirement related benefit plans at their respective measurement date. This rate is determined by NRG's Investment Committee based on information provided by the Company's actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine the future pension obligation as of December 31, 2013, 2012 and 2011 were based on the Aon Hewitt AA Above Median, or AAM, yield curve, which was designed by Aon Hewitt to provide a means for corporate plan sponsors to value the liabilities of defined pension benefit and other post retirement benefit plans. The AAM is a hypothetical Aa yield curve represented by a series of annualized individual discount rates from 0.5 to 99 years. Each bond issue is required to have an average rating of AA, when averaging all available ratings by Moody's Investor Services, Standard & Poor's and Fitch.

NRG employs a total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The Investment Committee reviews the asset mix periodically and as the plan assets increase in future years, the Investment Committee may examine other asset classes such as real estate or private equity. NRG employs a building block approach to determining the long-term rate of return for plan assets, with proper consideration given to diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed income are preserved, consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonableness and appropriateness.

The target allocations of NRG's pension plan assets were as follows for the years ended December 31, 2013 and 2012:

U.S. equity	38.5 - 45.5%
Non-U.S. equity	16.5 - 28%
U.S. fixed income	30 - 45%

Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. equities, as well as among growth, value, small and large capitalization stocks.

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

	Pension Benefit Payments	Other Postretirement Benefit Benefit Payments	Other Postretirement Benefit Medicare Prescription Drug Reimbursements
	(In millions)		
2014	$60	$9	$—
2015	53	10	—
2016	58	10	—
2017	59	10	—
2018	63	11	—
2019-2023	362	62	2

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total service and interest cost components	$1	$(1)
Effect on postretirement benefit obligation	14	(11)

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in STP, as discussed further in Note 27, Jointly Owned Plants. STPNOC, which operates and maintains STP, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. For the years ending December 31, 2013 and 2012, NRG reimbursed STPNOC $14 million and $15 million, respectively, towards its defined benefit plans. In 2014, NRG expects to reimburse STPNOC $18 million for its contributions towards the plans.

The Company has recognized the following in its statement of financial position, statement of operations and accumulated OCI related to its 44% interest in STP:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(In millions)			
Funded status — STPNOC benefit plans	$(42)	$(76)	$(52)	$(56)
Net periodic benefit costs	11	10	8	8
Other changes in plan assets and benefit obligations recognized in other comprehensive income	(31)	14	(10)	1

Defined Contribution Plans

NRG's employees are also eligible to participate in defined contribution 401(k) plans. Upon completion of the GenOn acquisition, NRG assumed GenOn's defined contribution 401(k) plans and amended the plan covering the majority of employees with NRG 401(k) plan features, effective January 1, 2013. On July 5, 2013, the GenOn defined contribution 401(k) plans were merged into the NRG 401(k) plan.

The Company's contributions to these plans were as follows:

	Year Ended December 31,		
	2013	2012 [(a)]	2011

	(In millions)		
Company contributions to defined contribution plans	$34	$24	$24

(a) Includes contributions to former GenOn plans for the period of December 15, 2012 to December 31, 2012.

Note 15 — Capital Structure

For the period from December 31, 2010 to December 31, 2013, the Company had 10,000,000 shares of preferred stock authorized, 500,000,000 shares of common stock authorized and 250,000 shares of preferred stock issued and outstanding. The following table reflects the changes in NRG's common shares issued and outstanding for each period presented:

	Common Issued	Treasury	Outstanding
Balance as of December 31, 2010	304,006,027	(56,808,672)	247,197,355
Shares issued under ESPP	—	120,127	120,127
Shares issued from LTIP	177,693	—	177,693
Share repurchases	—	(19,975,654)	(19,975,654)
Balance as of December 31, 2011	304,183,720	(76,664,199)	227,519,521
Shares issued under ESPP	—	158,481	158,481
Shares issued under LTIPs	996,262	—	996,262
Shares issued through GenOn acquisition	93,932,634	—	93,932,634
Balance as of December 31, 2012	399,112,616	(76,505,718)	322,606,898
Shares issued under ESPP	—	130,482	130,482
Shares issued under LTIPs	2,014,164	—	2,014,164
Share repurchases	—	(972,292)	(972,292)
Balance as of December 31, 2013	401,126,780	(77,347,528)	323,779,252

Common Stock

The following table summarizes NRG's common stock reserved for the maximum number of shares potentially issuable based on the conversion and redemption features of outstanding equity instruments and the long-term incentive plans as of December 31, 2013:

Equity Instrument	Common Stock Reserve Balance
3.625% Convertible perpetual preferred	16,000,000
Long-term incentive plans	21,121,160
Total	37,121,160

Common stock dividends — NRG paid its first quarterly dividend on the Company's common stock of $0.09 per share, or $0.36 per share on an annualized basis, on August 15, 2012. In 2013, the Company increased its annual common stock dividend by 33% to $0.48 per share. The following table lists the dividends paid per common share during 2013 and 2012:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2013	$0.09	$0.12	$0.12	$0.12
2012	$—	$—	$0.09	$0.09

On February 17, 2014, NRG paid a quarterly dividend on the Company's common stock of $0.12 per share.

Employee Stock Purchase Plan — Under the ESPP eligible employees may elect to withhold up to 10% of their eligible compensation to purchase shares of NRG common stock at 85% of its fair market value on the exercise date. An exercise date occurs each June 30 and December 31. As of December 31, 2013, there remained 888,388 shares of treasury stock reserved for issuance under the ESPP, and in the first quarter of 2014, 71,478 shares of common stock were issued to employee accounts from treasury stock.

2013 Capital Allocation Program — The Company was authorized to repurchase $200 million of its common stock in 2013 under the 2013 Capital Allocation Program. During the first quarter, the Company purchased 972,292 shares of NRG common stock for approximately $25 million at an average cost of $25.88 per share. As a result of the proposed acquisition of EME, the Company did not complete the remaining $175 million of share repurchases under the 2013 Capital Allocation Program.

Preferred Stock

3.625% Redeemable Preferred Stock

On August 11, 2005, NRG issued 250,000 shares of 3.625% Convertible Perpetual Preferred Stock, or 3.625% Preferred Stock, which is treated as Redeemable Preferred Stock, to the Credit Suisse Group in a private placement. The 3.625% Preferred Stock amount is located after the liabilities but before the stockholders' equity section on the balance sheet, due to the fact that the preferred shares can be redeemed in cash by the stockholder. The 3.625% Preferred Stock has a liquidation preference of $1,000 per share. Holders of the 3.625% Preferred Stock are entitled to receive, out of legally available funds, cash dividends at the rate of 3.625% per annum, or $36.25 per share per year, payable in cash quarterly in arrears commencing on December 15, 2005.

Each share of the 3.625% Preferred Stock is convertible during the 90-day period beginning August 11, 2015, at the option of NRG or the holder. Holders tendering the 3.625% Preferred Stock for conversion shall be entitled to receive, for each share of 3.625% Preferred Stock converted, $1,000 in cash and a number of shares of NRG common stock equal in value to the product of (a) the greater of (i) the difference between the average closing share price of NRG common stock on each of the twenty consecutive scheduled trading days starting on the date thirty exchange business days immediately prior to the conversion date, or the Market Price, and $29.54 and (ii) zero, times (b) 50.77. The number of shares of NRG common stock to be delivered under the conversion feature is limited to 16,000,000 shares. If upon conversion, the Market Price is less than $19.69, then the Holder will deliver to NRG cash or a number of shares of NRG common stock equal in value to the product of (i) $19.69 minus the Market Price, times (ii) 50.77. NRG may elect to make a cash payment in lieu of delivering shares of NRG common stock in connection with such conversion, and NRG may elect to receive cash in lieu of shares of common stock, if any, from the Holder in connection with such conversion. The conversion feature is considered an embedded derivative per ASC 815 that is exempt from derivative accounting as it is excluded from the scope pursuant to ASC 815.

If a fundamental change occurs, the holders will have the right to require NRG to repurchase all or a portion of the 3.625% Preferred Stock for a period of time after the fundamental change at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends. The 3.625% Preferred Stock is senior to all classes of common stock, and junior to all of the Company's existing and future debt obligations and all of NRG subsidiaries' existing and future liabilities and capital stock held by persons other than NRG or its subsidiaries.

Note 16 — Investments Accounted for by the Equity Method and Variable Interest Entities

NRG accounts for the Company's significant investments using the equity method of accounting. NRG's carrying value of equity investments can be impacted by impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates, as well as other adjustments.

The following table summarizes NRG's equity method investments as of December 31, 2013:

Name	Geographic Area	Economic Interest	
Avenal Solar Holdings LLC	United States	50.0	%
GenConn Energy LLC	United States	50.0	%
Saguaro Power Company	United States	50.0	%
Sherbino I Wind Farm LLC	United States	50.0	%
Texas Coastal Ventures, LLC	United States	50.0	%
Sabine CoGen, LP	United States	50.0	%
Sunora Energy Solutions I LLC	United States	50.0	%
Gladstone Power Station	Australia	37.5	%

	As of December 31,	
	2013	2012
	(In millions)	
Undistributed earnings from equity investments	$94	$149

Variable Interest Entities

NRG accounts for its interests in certain entities that are considered VIEs under ASC 810, but NRG is not the primary beneficiary, under the equity method.

GenConn Energy LLC — NRG owns a 50% interest in GenConn, a limited liability company formed to construct, own and operate two 190MW peaking generation facilities in Connecticut at NRG's Devon and Middletown sites. Each of these facilities was constructed pursuant to 30-year cost of service type contracts with the Connecticut Light & Power Company. All four units at the GenConn Devon facility reached commercial operation in 2010 and were released to the ISO-NE by July 2010. In June 2011, the GenConn Middletown facility reached commercial operation and was released to the ISO-NE. The project was funded through equity contributions from the owners and non-recourse, project level debt. As of December 31, 2013, NRG had a $118 million equity investment in GenConn. NRG's maximum exposure to loss is limited to its equity investment.

In April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a seven-year term loan facility, and also entered into a five-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the working capital facility. In March 2012, the working capital facility was amended to $35 million. On September 17, 2013, GenConn refinanced its existing project financing facility. The refinanced facility is comprised of a $237 million note with an interest rate of 4.73% and a maturity date of July 2041 and a 5-year, $35 million working capital facility which can be used to issue letters of credit at an interest rate of 1.875%. The refinancing is secured by all of the GenConn assets.

As discussed in Note 21, Related Party Transactions, in 2010 and 2011, NRG earned revenues from construction management agreements with Devon and Middletown and interest income from a note receivable with GenConn.

Sherbino I Wind Farm LLC — NRG owns a 50% interest in Sherbino, a joint venture with BP Wind Energy North America Inc. Sherbino is a 150 MW wind farm, which commenced commercial operations in October 2008. In December 2008, Sherbino entered into a 15-year term loan facility which is non-recourse to NRG. As of December 31, 2013, the outstanding principal balance of the term loan facility was $114 million, and is secured by substantially all of Sherbino's assets and membership interests. NRG's maximum exposure to loss is limited to its equity investment, which was $87 million as of December 31, 2013.

Texas Coastal Ventures, LLC — NRG owns a 50% interest in Texas Coastal Ventures, LLC, or TCV, a joint venture with Hilcorp Energy I, L.P., through its subsidiary Petra Nova LLC. Texas Coastal Ventures was formed by Petra

Nova and Hilcorp for the purpose of using carbon dioxide captured from flue gas from certain of NRG's coal-generating power plants in the United States Gulf Coast in an enhanced oil recovery process. TCV is managed by the joint venture participants and operated by Hilcorp. TCV entered into service agreements with Petra Nova LLC, which include a management services agreement for the operation and management of the joint venture's pipeline assets, as well as a CO_2 supply agreement having an initial term of twenty years. NRG's maximum exposure to loss is limited to its equity investment, which was $63 million as of December 31, 2013.

Other Equity Investments

Gladstone — Through a joint venture, NRG owns a 37.5% interest in Gladstone, a 1,613 megawatt coal-fueled power generation facility in Queensland, Australia. The power generation facility is managed by the joint venture participants and the facility is operated by NRG. Operating expenses incurred in connection with the operation of the facility are funded by each of the participants in proportion to their ownership interests. Coal is sourced from local mines in Queensland. NRG and the joint venture participants receive their respective share of revenues directly from the off takers in proportion to the ownership interests in the joint venture. Power generated by the facility is primarily sold to an adjacent aluminum smelter, with excess power sold to the Queensland Government owned utility under long term supply contracts. The Company recorded an impairment loss for Gladstone in the fourth quarter of 2013 of $92 million, as described in Note 10, Asset Impairments. NRG's investment in Gladstone was $188 million as of December 31, 2013.

Note 17 — (Loss)/Earnings Per Share

Basic (loss)/earnings per common share is computed by dividing net (loss)/income less accumulated preferred stock dividends by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted (loss)/earnings per share is computed in a manner consistent with that of basic (loss)/earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period.

Dilutive effect for equity compensation and other equity instruments — The outstanding non-qualified stock options, non-vested restricted stock units, deferred stock units, market stock units and performance units are not considered outstanding for purposes of computing basic (loss)/earnings per share. However, these instruments are included in the denominator for purposes of computing diluted (loss)/earnings per share under the treasury stock method. The if-converted method is used to determine the dilutive effect of embedded derivatives in the Company's 3.625% Preferred Stock.

The reconciliation of NRG's basic (loss)/earnings per share to diluted (loss)/earnings per share is shown in the following table:

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except per share amounts)		
Basic (loss)/earnings per share attributable to NRG common stockholders			
Net (loss)/income attributable to NRG Energy, Inc.	$(386)	$295	$197
Dividends for preferred shares	9	9	9
(Loss)/Income Available to Common Stockholders	$(395)	$286	$188
Weighted average number of common shares outstanding	323	232	240
(Loss)/Earnings per weighted average common share — basic	$(1.22)	$1.23	$0.78
Diluted (loss)/earnings per share attributable to NRG common stockholders			
Weighted average number of common shares outstanding	323	232	240
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	—	2	1
Total dilutive shares	323	234	241
(Loss)/Earnings per weighted average common share — diluted	$(1.22)	$1.22	$0.78

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

	Year Ended December 31,		
	2013	2012	2011
	(In millions of shares)		
Equity compensation	9	8	7
Embedded derivative of 3.625% redeemable perpetual preferred stock	16	16	16
Total	25	24	23

Note 18 — Segment Reporting

Effective June 2013, the Company's segment structure and its allocation of corporate expenses were updated to reflect how management currently makes financial decisions and allocates resources. The Company has recast data from prior periods to reflect this change in reportable segments to conform to the current year presentation. The Company's businesses are primarily segregated based on the Retail Business, conventional power generation, alternative energy businesses, NRG Yield, and corporate activities. Within NRG's conventional power generation, there are distinct components with separate operating results and management structures for the following geographical regions: Texas, East, South Central, West and Other, which includes international businesses and maintenance services. The Company's alternative energy segment includes solar and wind assets (excluding those in the NRG Yield segment), electric vehicle services and the carbon capture business. NRG Yield includes certain of the Company's contracted generation assets including three natural gas or dual-fired facilities, eight utility-scale solar and wind generation facilities, two portfolios of distributed solar facilities and thermal infrastructure assets. Intersegment sales are accounted for at market.

For the years ended December 31, 2013, 2012, and 2011, there were no customers from whom the Company derived more than 10% of the Company's consolidated revenues.

	Year Ended December 31, 2013										
		Conventional Power Generation									
	Retail	Texas	East	South Central	West	Other	Alternative Energy	NRG Yield	Corporate	Eliminations	Total
	(In millions)										
Operating revenues[(a)]	$6,241	$2,106	$3,209	$874	$475	$153	$233	$313	$7	$(2,316)	$11,295
Operating expenses	5,535	1,826	2,512	750	318	144	147	134	50	(2,307)	9,109
Depreciation and amortization	142	457	320	98	55	4	108	51	21	—	1,256
Impairment charges	—	—	459	—	—	—	—	—		—	459
Acquisition-related transaction and integration costs	—	—	—	—	—	—	—	—	128	—	128
Operating income/(loss)	564	(177)	(82)	26	102	5	(22)	128	(192)	(9)	343
Equity in earnings/(loss) of unconsolidated affiliates	—	—	—	4	(11)	6	(4)	22	—	(10)	7
Impairment losses on investments	—	—	—	—	—	(99)	—	—	—	—	(99)
Other income, net	—	1	28	1	1	3	2	2	74	(99)	13
Loss on debt extinguishment	—	—	—	—	—	—	—	—	(50)	—	(50)
Interest expense	(2)	(1)	(85)	(18)	(14)	—	(57)	(35)	(735)	99	(848)
Income/(loss) before income taxes	562	(177)	(139)	13	78	(85)	(81)	117	(903)	(19)	(634)
Income tax (benefit)/expense	—	—	—	—	—	(29)	—	8	(261)	—	(282)
Net income/(loss)	$562	$(177)	$(139)	$13	$78	$(56)	$(81)	$109	$(642)	$(19)	$(352)

Less: Net income attributable to noncontrolling interest	$—	$—	$—	$—	$—	$—	$27	$13	$—	$(6)	$34
Net income/(loss) attributable to NRG Energy, Inc.	$562	$(177)	$(139)	$13	$78	$(56)	$(108)	$96	$(642)	$(13)	$(386)
Balance sheet											
Equity investments in affiliates	—	—	5	17	(35)	188	150	227	—	(99)	453
Capital expenditures[a]	30	119	181	88	136	15	818	116	73		1,576
Goodwill	260	1,713	—	—	—	—	12	—	—	—	1,985
Total assets	4,717	11,656	8,437	2,431	1,638	468	6,213	2,313	25,290	(29,261)	33,902

(b) Operating revenues include inter-segment sales and net derivative gains and losses of:	$9	$2,058	$87	$16	$4	$64	$23	$—	$7

(a) Includes accruals.

	Year Ended December 31, 2012										
		Conventional Power Generation									
	Retail	Texas	East[d]	South[d] Central	West[d]	Other	Alternative Energy	NRG Yield	Corporate[f]	Eliminations	Total
	(In millions)										
Operating revenues[c]	$5,772	$2,074	$854	$807	$259	$173	$125	$175	$17	$(1,834)	$8,422
Operating expenses	5,065	1,712	754	695	194	161	87	119	47	(1,819)	7,015
Depreciation and amortization	162	458	137	93	12	2	49	25	12	—	950
Acquisition-related transaction and integration costs	—	—	—	—	—	—	—	—	107	—	107
Operating income/(loss)	545	(96)	(37)	19	53	10	(11)	31	(149)	(15)	350
Equity in earnings/(loss) of unconsolidated affiliates	—	—	—	—	7	13	—	19	(2)	—	37
Impairment losses on investments	—	—	—	—	—	—	—	—	(2)	—	(2)
Bargain purchase gain related to GenOn acquisition	—	—	—	—	—	—	—	—	296	—	296
Other income, net	—	2	2	1	1	4	—	1	26	(18)	19
Loss on debt extinguishment	—	—	—	—	—	—	—	—	(51)	—	(51)
Interest expense	(4)	—	(20)	(18)	(2)	(3)	(26)	(28)	(578)	18	(661)
Income/(loss) before income taxes	541	(94)	(55)	2	59	24	(37)	23	(460)	(15)	(12)
Income tax expense/(benefit)	—	—	—	—	—	3	—	10	(340)	—	(327)
Net income/(loss)	541	(94)	(55)	2	59	21	(37)	13	(120)	(15)	315
Less: Net income attributable to noncontrolling interest	—	—	—	—	—	—	20		—	—	20
Net income/(loss) attributable to NRG Energy, Inc.	$541	$(94)	$(55)	$2	$59	$21	$(57)	$13	$(120)	$(15)	$295
Balance sheet											
Equity investments in affiliates	$—	$—	$7	$19	$27	$322	$163	$220	$10	$(92)	$676
Capital expenditures [e]	19	117	71	36	244	16	2,700	478	12	—	3,693

Goodwill	231	1,713	—	—	—	—	12	—	—	—	1,956
Total assets	$3,122	$10,988	$6,972	$1,935	$1,313	$442	$5,367	$1,964	$28,330	$(25,450)	$34,983
(c) Operating revenues include inter-segment sales and net derivative gains and losses of:	$5	$1,657	$73	$—	$—	$69	$20	$—	$10		

(d) Includes GenOn results for the period December 15, 2012 to December 31, 2012.
(e) Includes accruals.

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	Year Ended December 31, 2011										
		Conventional Power Generation									
	Retail[(f)(g)]	Texas[(f)]	East[(f)]	South Central[(f)]	West[(f)]	Other[(f)]	Alternative Energy[(f)]	NRG Yield[(f)]	Corporate[(f)]	Eliminations	Total
		(In millions)									
Operating revenues	$5,642	$2,832	$924	$817	$149	$183	$22	$164	$11	$(1,665)	$9,079
Operating expenses	5,113	1,910	859	703	92	178	62	114	30	(1,673)	7,388
Depreciation and amortization	159	463	118	89	10	—	23	22	12	—	896
Impairment losses	—	160	—	—	—	—	—		—	—	160
Operating income/(loss)	370	299	(53)	25	47	5	(63)	28	(31)	8	635
Equity in earnings of unconsolidated affiliates	—	—	—	—	9	9	4	13	—	—	35
Impairment losses on investments	—	—	—	—	—	—	—	—	(495)	—	(495)
Other income, net	—	1	2	2	—	5	3	2	21	(17)	19
Loss on debt extinguishment	—	—	—	—	—	—	—	—	(175)	—	(175)
Interest (expense)/income	(4)	16	(47)	(41)	(2)	(6)	(7)	(19)	(571)	16	(665)
Income/(loss) before income taxes	366	316	(98)	(14)	54	13	(63)	24	(1,251)	7	(646)
Income tax (benefit)/expense	(3)	—	—	—	—	—	—	9	(847)	(2)	(843)
Net income/(loss)	369	316	(98)	(14)	54	13	(63)	15	(404)	9	197
(f) Operating revenues include inter-segment sales and net derivative gains and losses of:	$5	$1,586	$43	$—	$—	$25	$23	$—	$—		

(g) Includes Green Mountain Energy results and Energy Plus results for the period October 1, 2011 to December 31, 2011.

Note 19 — Income Taxes

The income tax provision from continuing operations consisted of the following amounts:

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except percentages)		
Current			
U.S. Federal	$—	$—	$(538)
State	11	20	10
Foreign	—	13	16
Total — current	11	33	(512)
Deferred			
U.S. Federal	(207)	(326)	(317)

State	(57)	(24)	(5)
Foreign	(29)	(10)	(9)
Total — deferred	(293)	(360)	(331)
Total income tax benefit	$(282)	$(327)	$(843)
Effective tax rate	44.5%	2,725.0%	130.5%

The following represents the domestic and foreign components of loss before income tax benefit:

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
U.S.	$(549)	$(41)	$(680)
Foreign	(85)	29	34
Total	$(634)	$(12)	$(646)

A reconciliation of the U.S. federal statutory rate of 35% to NRG's effective rate is as follows:

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except percentages)		
Loss Before Income Taxes	$(634)	$(12)	$(646)
Tax at 35%	(222)	(4)	(226)
State taxes, including change in rate, net of federal benefit	11	1	15
Foreign operations	5	(24)	(3)
Federal and state tax credits	(36)	(158)	(1)
Valuation allowance	(5)	5	(63)
Expiration/utilization of capital losses	10	—	45
Reversal of valuation allowance on expired/utilized capital losses	(10)	—	(45)
Impact of non-taxable equity earnings	(14)	(7)	—
Bargain purchase gain related to GenOn acquisition	—	(104)	—
Foreign earnings	—	—	4
Interest accrued on uncertain tax positions	(3)	2	2
Production tax credit	(14)	(14)	(14)
Reversal of uncertain tax position reserves	(11)	(13)	(561)
Tax expense attributable to consolidated partnerships	8	—	—
Other	(1)	(11)	4
Income tax benefit	$(282)	$(327)	$(843)
Effective income tax rate	44.5%	2,725.0%	130.5%

For the year ended December 31, 2013, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to generation of ITCs from the Company's Agua Caliente solar project in Arizona of $36 million and production tax credits, or PTCs, generated from certain Texas wind facilities of $14 million.

For the year ended December 31, 2012, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of ITCs from the Company's Agua Caliente solar project in Arizona of $158 million, a benefit of $104 million resulting from the gain on bargain purchase of GenOn, and PTCs generated from certain Texas wind facilities of $14 million.

The effective tax rate for the year ended December 31, 2011, differs from the statutory rate of 35% primarily due to a benefit of $633 million resulting from the resolution of the federal tax audit. The benefit is predominantly due to the recognition of previously uncertain tax benefits that were settled upon audit in 2011 and that were mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes.

The temporary differences, which gave rise to the Company's deferred tax assets and liabilities consisted of the following:

	As of December 31, 2013	2012
	(In millions)	
Deferred tax liabilities:		
Emissions allowances	$15	$15
Difference between book and tax basis of property	22	123
Derivatives, net	334	323
Goodwill	191	165
Cumulative translation adjustments	9	19
Intangibles amortization (excluding goodwill)	—	85
Investment in projects	540	52
Other	—	—
Total deferred tax liabilities	1,111	782
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	203	232
Discount/premium on notes	111	156
Differences between book and tax basis of contracts	285	343
Pension and other postretirement benefits	168	274
Equity compensation	57	57
Bad debt reserve	18	14
U.S. capital loss carryforwards	1	1
U.S. Federal net operating loss carryforwards	1,381	605
Foreign net operating loss carryforwards	77	89
State net operating loss carryforwards	161	89
Foreign capital loss carryforwards	1	1
Deferred financing costs	3	33
Federal and state tax credits	308	258
Federal benefit on state uncertain tax positions	23	18
Intangibles amortization (excluding goodwill)	20	—
Other	23	7
Total deferred tax assets	2,840	2,177
Valuation allowance	(291)	(191)
Total deferred tax assets, net of valuation allowance	2,549	1,986
Net deferred tax asset	$1,438	$1,204

The following table summarizes NRG's net deferred tax position:

	As of December 31, 2013	2012
	(In millions)	
Net deferred tax asset — current	$258	$56
Net deferred tax asset — noncurrent	1,202	1,203
Net deferred tax liability — noncurrent	$(22)	$(55)
Net deferred tax asset	$1,438	$1,204

Deferred tax assets and valuation allowance

Net deferred tax balance — As of December 31, 2013, and 2012, NRG recorded a net deferred tax asset of $1.4 billion and $1.2 billion, respectively. The Company believes it is more likely than not that the results of future operations will generate sufficient taxable income which includes the future reversal of existing taxable temporary differences to realize deferred tax assets, net of valuation allowances. In arriving at this conclusion to utilize projections of future profit before tax in our estimate of future taxable income, we considered the profit before tax generated in recent years. Based on our assessment of positive and negative evidence, including available tax planning strategies, NRG believes that it is more likely than not that a benefit will not be realized on $291 million and $191 million of tax assets as of December 31, 2013 and 2012, respectively, thus a valuation allowance has been recorded. The Company estimates it will need to generate future taxable income of approximately $3.1 billion, to fully realize the net federal deferred tax asset before expiration commencing in 2026.

In connection with the accounting for the GenOn acquisition, the Company recorded the realizable deferred tax assets and liabilities acquired, primarily consisting of net operating losses and other temporary differences. In addition, the excess of GenOn's historical tax basis of assets and liabilities over the amount assigned to the fair value of the assets acquired and liabilities assumed generated deferred tax assets and liabilities that were recorded on the acquisition date.

NOL carryforwards — At December 31, 2013, the Company had tax effected cumulative domestic NOLs consisting of carryforwards for federal income tax purposes of $1.4 billion and state of $161 million. In addition, NRG has cumulative foreign NOL carryforwards of $77 million of which $4 million will expire through 2016 and of which $73 million do not have an expiration date.

Valuation allowance — As of December 31, 2013, the Company's tax effected valuation allowance was $291 million, consisting of $216 million for state deferred tax assets, primarily operating loss carryovers, and $75 million for foreign deferred tax assets, primarily operating loss carryovers for which there is insufficient earnings to support future realization.

Taxes Receivable and Payable

As of December 31, 2013, NRG recorded a current tax payable of $12 million that represents a tax liability due for domestic state taxes of $11 million, as well as foreign taxes payable of $1 million. NRG has a domestic tax receivable of $551 million, of which $539 million relates to federal cash grants applied for eligible solar energy projects net of sequestration of $42 million; the balance of $12 million is related to federal refunds anticipated from multiple income tax carry-back claims to prior tax years. In addition, a $65 million non-current receivable has been established relating to property tax refunds due to the New York State Empire Zone program generated in years 2010 through 2013.

Uncertain tax benefits

NRG has identified uncertain tax benefits whose after-tax value was $115 million that if recognized, would impact the Company's income tax expense.

As of December 31, 2013, and 2012, NRG has recorded a non-current tax liability of $61 million and $72 million, respectively. As of December 31, 2012 and 2011, the balance primarily related to positions taken on various state returns, including accrued interest.

The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense. During the year ended December 31, 2013, the Company recognized a benefit of $5 million in interest and penalties and accrued interest of $2 million. For the year ended December 31, 2012, the Company accrued interest of $3 million. As of December 31, 2013, and 2012, NRG had cumulative interest and penalties related to these uncertain tax benefits of $14 million and $15 million, respectively.

Tax jurisdictions — NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including operations located in Australia.

Prior to the GenOn acquisition in December 2012, the Company was not subject to U.S. federal income tax examinations for years prior to 2007. GenOn is no longer subject to U.S. federal income tax examinations for years prior to 2010. With few exceptions, state and local income tax examinations are no longer open for years before 2007. The Company's significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2008.

During 2011, the Company settled the Internal Revenue Service's audit examination for the years 2004 through 2006 and recognized a benefit of $633 million. The benefit is predominantly due to the recognition of previously uncertain tax benefits mainly composed of net operating losses of $536 million which had been classified as capital loss carryforwards for financial statement purposes. The Company continues to be under examination for various state jurisdictions for multiple years.

The following table reconciles the total amounts of uncertain tax benefits:

	As of December 31,	
	2013	2012
	(In millions)	
Balance as of January 1	$193	$178
Increase due to current year positions	2	21
Decrease due to current year positions	—	(3)
Increase due to prior year positions	4	13
Decrease due to prior year positions	(40)	(21)
Increase due to acquisitions	—	5
Decrease due to settlements and payments	(44)	—
Uncertain tax benefits as of December 31	$115	$193

Note 20 — Stock-Based Compensation

NRG Energy, Inc. Long-Term Incentive Plan

As of December 31, 2013, and 2012, a total of 22,000,000 shares of NRG common stock were authorized for issuance under the NRG LTIP, subject to adjustments in the event of reorganization, recapitalization, stock split, reverse stock split, stock dividend, and a combination of shares, merger or similar change in NRG's structure or outstanding shares of common stock. There were 7,238,065 and 7,580,318 shares of common stock remaining available for grants under the NRG LTIP as of December 31, 2013, and 2012, respectively.

GenOn Acquisition

Effective December 14, 2012, in connection with the GenOn acquisition, as discussed in Note 3, Business Acquisitions and Dispositions, NRG assumed the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, and the name was changed to the NRG 2010 Stock Plan for GenOn Employees, or the NRG GenOn LTIP. As of December 31, 2013, 5,558,390 shares of NRG common stock were authorized for issuance under the NRG GenOn LTIP, and there were 1,053,485 shares of common stock remaining available for grants under the NRG GenOn LTIP. In addition, NRG assumed certain other terminated GenOn plans, under which NRG will not grant any further awards. All outstanding awards under the NRG GenOn LTIP and the terminated plans were appropriately adjusted based on the Exchange Ratio, and remain subject to the terms and conditions of the applicable plans prior to the acquisition.

In addition, upon completion of the GenOn acquisition, the following occurred to GenOn's outstanding stock-based incentive awards: (i) each outstanding and unvested RSU that was granted under the GenOn plans before 2012 vested in full and was exchanged for shares of NRG common stock in the acquisition based on the Exchange Ratio; (ii) each outstanding and unvested GenOn NQSO that was granted under the GenOn plans before 2012 vested in full and converted into an option to purchase NRG common stock; (iii) each outstanding and unvested RSU that was granted under the GenOn plans in 2012, was converted into an unvested RSU of NRG, and (iv) each outstanding and unvested GenOn NQSO that was granted under the GenOn plans during 2012 was converted into an NQSO to purchase NRG common stock on the same vesting schedule.

Under the acquisition method of accounting, GenOn employee NQSOs and RSUs which vested upon close of the acquisition were measured and recorded at acquisition-date fair value, resulting in additional purchase price consideration of $28 million. As of December 14, 2012, unvested NQSOs that were converted to options to purchase NRG common stock and RSUs that were converted to NRG RSUs were recorded in NRG's consolidated balance sheet.

Non-Qualified Stock Options

NQSOs granted under the NRG LTIP and the NRG GenOn LTIP typically have three-year graded vesting schedules beginning on the grant date and become exercisable at the end of the requisite service period. NRG recognizes compensation costs for NQSOs over the requisite service period for the entire award. The maximum contractual term is ten years for 2.8 million of NRG's outstanding NQSOs, and six years for the remaining 1.2 million NQSOs. No NQSOs were granted in 2013.

The following table summarizes the Company's NQSO activity and changes during the year:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)
	(In whole)			
Outstanding at December 31, 2012	6,677,885	$28.85	4	$17
Forfeited	(1,044,902)	27.75		
Exercised	(1,656,002)	14.28		
Outstanding at December 31, 2013	3,976,981	35.20	2	17
Exercisable at December 31, 2013	3,592,810	31.80	2	13

The following table summarizes the weighted average grant date fair value of options granted, the total intrinsic value of options exercised, and the cash received from the exercises of options:

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except for weighted average)		
Weighted average grant date fair value per option granted	$—	$—	$8.73
Total intrinsic value of options exercised	19	0.3	0.2
Cash received from options exercised	33	1	2

Restricted Stock Units

As of December 31, 2013, RSUs granted under the Company's LTIPs fully vest three years from the date of issuance. Fair value of the RSUs is based on the closing price of NRG common stock on the date of grant. The following table summarizes the Company's non-vested RSU awards and changes during the year:

	Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Non-vested at December 31, 2012	2,608,551	$21.28
Granted	617,009	23.37
Forfeited	(322,448)	21.34
Vested	(879,933)	22.64
Non-vested at December 31, 2013	2,023,179	21.22

The total fair value of RSUs vested during the years ended December 31, 2013, 2012, and 2011, was $22 million, $18 million and $2 million, respectively. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2013, 2012, and 2011 was $23.37, $17.90, and $22.78, respectively.

Deferred Stock Units

DSUs represent the right of a participant to be paid one share of NRG common stock at the end of a deferral period established under the terms of the award. DSUs granted under the Company's LTIPs are fully vested at the date of issuance. Fair value of the DSUs, which is based on the closing price of NRG common stock on the date of grant, is recorded as compensation expense in the period of grant.

The following table summarizes the Company's outstanding DSU awards and changes during the year:

	Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Outstanding at December 31, 2012	697,515	$20.91
Granted	205,667	23.18
Conversions [(a)]	(524,636)	22.55
Outstanding at December 31, 2013	378,546	19.78

(a) 52,864 Deferred Stock Units were converted to cash for the year ended December 31, 2013.

The aggregate intrinsic values for DSUs outstanding as of December 31, 2013, 2012, and 2011 were approximately $7 million, $15 million, and $8 million respectively. The aggregate intrinsic values for DSUs converted to common stock for the years ended December 31, 2013, 2012, and 2011 were $12 million, $1.4 million and $0.4 million, respectively. The weighted average grant date fair value of DSUs granted during the years ended December 31, 2013, 2012, and 2011 was $23.18, $16.33 and $24.31, respectively.

Market Stock Units

MSUs are restricted grants where the quantity of shares increases and decreases alongside the Company's Total Shareholder Return, or TSR. Each MSU represents the potential to receive NRG common stock after the completion of three years of service from the date of grant. The number of shares of NRG common stock to be paid (if any) as of the vesting date for each MSU will depend on the TSR. The number of shares of common stock to be paid as of the vesting date for each MSU is equal to: (i) one half of one share of common stock if the TSR has decreased by no more than 50% of the value of the common stock on the date of grant; (ii) one share of common stock, if the TSR equals the value of the common stock on the date of grant; and (iii) two shares of common stock if the TSR is 200% or greater of the value of the common stock on the date of grant. If the TSR is less than 50% of the value of the common stock on the date of grant, no common stock will be paid. If the TSR is between 50% and 200%, shares awarded are interpolated. The value of the common stock on the date of grant is based on the 20-day average of the common stock closing price.

The following table summarizes the Company's non-vested MSU awards and changes during the year:

	Units	Weighted Average Grant-Date Fair Value per Unit
	(in whole)	
Non-vested at December 31, 2012	1,003,920	$22.43
Granted	1,066,626	27.46
Vested	(20,000)	26.64
Forfeited	(214,040)	24.16
Non-vested at December 31, 2013	1,836,506	24.72

The weighted average grant date fair value of MSUs granted during the years ended December 31, 2013, 2012 and 2011, was $27.46, $22.11 and $27.59, respectively.

The fair value of MSUs is estimated on the date of grant using a Monte Carlo simulation model and expensed over the service period, which equals the vesting period. Significant assumptions used in the fair value model with respect to the Company's MSUs are summarized below:

	2013	2012
Expected volatility	27.12%-29.11%	29.60%-35.98%
Expected term (in years)	3	3
Risk free rate	0.37%-0.59%	0.29%-0.40%

For the years ended December 31, 2013 and 2012, expected volatility is calculated based on NRG's historical stock price volatility data over the period commensurate with the expected term of the MSU, which equals the vesting period.

Performance Units

PUs granted under the Company's LTIP fully vest three years from the date of issuance. PUs are paid out upon vesting if the Measurement Price is equal to or greater than Threshold Price. The Threshold Price, Target Price and Maximum Price are determined on the date of issuance. The payout for each PU will be equal to: (i) a pro-rata amount between 0.5 and 1 share of common stock, if the Measurement Price is equal to or greater than the target Threshold Price but less than the Target Price; (ii) one share of common stock, if the Measurement Price equals the Target Price; (iii) a pro-rata amount between one and two shares of common stock, if the Measurement Price is greater than the Target Price but less than the Maximum Price; and (iv) two shares of common stock, if the Measurement Price is equal to, or greater than, the Maximum Price.

The following table summarizes the Company's non-vested PU awards and changes during the year:

	Outstanding Units	Weighted Average Grant-Date Fair Value per Unit
	(In whole)	
Non-vested at December 31, 2012	647,200	$21.88
Vested	(36,700)	19.89
Forfeited	(296,200)	23.28
Non-vested at December 31, 2013	314,300	20.80

The weighted average grant date fair value of PUs granted during the year ended December 31, 2011 was $20.80. No PUs were granted in 2013 or 2012.

The fair value of PUs is estimated on the date of grant using a Monte Carlo simulation model and expensed over the service period, which equals the vesting period.

Supplemental Information

The following table summarizes NRG's total compensation expense recognized for the years presented as well as total non-vested compensation costs not yet recognized and the period over which this expense is expected to be recognized as of December 31, 2013, for each of the five types of awards issued under the LTIPs. Minimum tax withholdings of $13 million, $6 million, and $1 million for the years ended December 31, 2013, 2012, and 2011, respectively, are reflected as a reduction to Additional Paid-in Capital on the Company's Consolidated Balance Sheet, and are reflected as operating activities on the Company's Consolidated Statement of Cash Flows.

	Compensation Expense			Non-vested Compensation Cost	
				Unrecognized Total Cost	Weighted Average Recognition Period Remaining (In years)
	Year Ended December 31			As of December 31	
Award	2013	2012	2011	2013	2013
	(In millions, except weighted average data)				
NQSOs	$4	$6	$8	$1	1.1
RSUs	18	21	12	18	1.4
DSUs	2	2	2	—	0
MSUs	14	7	—	28	1.7
PUs	2	4	5	—	0
Total	$40	$40	$27	$47	
Tax detriment recognized	$(12)	$8	$1		

Note 21 — Related Party Transactions

The following table summarizes NRG's material related party transactions with affiliates that are included in the Company's operating revenues, operating costs and other income and expense:

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Revenues from Related Parties Included in Operating Revenues			
Gladstone	$6	$7	$7
GenConn [(a)]	5	6	3
Total	$11	$13	$10
Interest income from Related Parties Included in Other Income and Expense			
GenConn [(a)]	$—	$—	$1
Kraftwerke Schkopau GBR [(b)]	—	2	4
Total	$—	$2	$5

(a) The period in 2011 is from January 1, 2011 to June 30, 2011.

(b) The period in 2012 is from January 1, 2012 to July 17, 2012.

Gladstone — NRG provides services to Gladstone, an equity method investment, under an operations and maintenance agreement. Fees for services under this contract primarily include recovery of NRG's costs of operating the plant as approved in the annual budget, as well as, a base monthly fee.

GenConn — NRG has O&M agreements with GenConn Devon and GenConn Middletown that began in June 2011. Under a construction management agreement with GenConn, NRG had received fees for management, design and construction services. The construction at GenConn was completed in June 2011. In addition, NRG entered into a loan agreement with GenConn during 2009, pursuant to which it received interest income, which was converted into equity during 2011. See further discussion in Note 16, Investments Accounted for by the Equity Method and Variable Interest Entities.

Kraftwerke Schkopau GBR — SEG had a loan agreement with Kraftwerke Schkopau GBR, a partnership between Saale Energie GmbH and E.ON Kraftwerke GmbH, pursuant to which NRG received interest income. On July 17, 2012, the Company completed the sale of its 100% interest in Saale Energie GmbH, as discussed in Note 3, Business Acquisitions and Dispositions.

Conemaugh and Keystone facilities — The Company operates the Conemaugh and Keystone facilities under five-year agreements that expire in December 2015 that, subject to certain provisions and notifications, could be terminated annually with one year's notice. The Company is reimbursed by the other owners for the cost of direct services provided to the Conemaugh and Keystone facilities. Additionally, the Company received fees of $10 million during 2013 and $1 million in 2012 subsequent to the GenOn acquisition. These fees, which are recorded in O&M expense in the consolidated statements of operations, are primarily to cover NRG REMA LLC's administrative support costs of providing these services.

Note 22 — Commitments and Contingencies
Operating Lease Commitments
GenOn Mid-Atlantic Leases
The Company leases a 100% interest in the Dickerson and Morgantown coal generation units and associated property through 2029 and 2034, respectively, through its indirect subsidiary, GenOn MidAtlantic, LLC. The Company accounts for these leases as operating leases and records lease expense on a straight-line basis over the lease term. As further described in Note 3, Business Acquisitions and Dispositions, in connection with the acquisition of GenOn, the Company recorded the out-of-market value as a liability in out-of-market contracts of $604 million. The liability will be amortized through rent expense on a straight-line basis over the term of the lease. The Company expects to record lease expense, net of amortization of the out-of-market liability, of approximately $44 million per year through the term of the lease.
Future minimum lease commitments under the GenOn Mid-Atlantic operating leases for the years ending after December 31, 2013, are as follows:

Period	(In millions)
2014	$131
2015	110
2016	150
2017	144
2018	105
Thereafter	686
Total	$1,326

REMA Leases
The Company, through its indirect subsidiary, NRG REMA, LLC, leases a 100% interest in the Shawville coal generation facility through 2026 and leases 16.5% and 16.7% interest in the Keystone and Conemaugh coal generation facilities through 2034, and expects to make payments under the lease through 2029. The Company accounts for these leases as operating leases and records lease expense on a straight-line basis over the lease term. As further described in Note 3, Business Acquisitions and Dispositions, in connection with the acquisition of GenOn, the Company recorded the out-of-market value as a liability in out-of-market contracts of $186 million. The liability will be amortized through rent expense on a straight-line basis over the term of the lease. The Company expects to record lease expense, net of amortization of the out-of-market liability, of approximately $33 million per year through the term of the lease.
During 2011, GenOn completed an analysis of the cost of environmental controls required for the Shawville generating facility, including the installation of cooling towers. After evaluation of the forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes and other factors, GenOn concluded that the forecasted returns on investments necessary to comply with the environmental regulations are insufficient. Accordingly, NRG plans to place the coal-fired units at the Shawville generating facility in a long-term protective layup in April 2015. Under the lease agreement for Shawville, NRG's obligations generally are to pay the required rent and to maintain the leased assets in accordance with the lease documentation, including in compliance with prudent competitive electric generating industry practice and applicable laws. NRG will continue to evaluate options under the lease, including termination of the lease for economic obsolescence and/or keeping the facility in long-term protective layup during the term of the lease, or continuing operations with a different fuel.
Future minimum lease commitments under the REMA operating leases for the years ending after December 31, 2013, are as follows:

Period	(In millions)
2014	$63
2015	56
2016	61
2017	63
2018	55
Thereafter	400

Total	$698

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Other Operating Leases

NRG leases certain Company facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2041. NRG also has certain tolling arrangements to purchase power which qualifies as operating leases. Certain operating lease agreements over their lease term include provisions such as scheduled rent increases, leasehold incentives, and rent concessions. The Company recognizes the effects of these scheduled rent increases, leasehold incentives, and rent concessions on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed. Lease expense under operating leases was$88 million, $67 million, and $81 million for the years ended December 31, 2013, 2012, and 2011, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2013, are as follows:

Period	(In millions)
2014	$79
2015	78
2016	63
2017	41
2018	38
Thereafter	138
Total [(a)]	$437

(a) Amounts in the table exclude future sublease income of $20 million associated with GenOn's long-term lease for its corporate headquarters in Houston, Texas.

Coal, Gas and Transportation Commitments

NRG has entered into long-term contractual arrangements to procure fuel and transportation services for the Company's generation assets and for the years ended December 31, 2013, 2012, and 2011, the Company purchased $2.8 billion, $1.4 billion, and $1.6 billion, respectively, under such arrangements.

As of December 31, 2013, the Company's commitments under such outstanding agreements are estimated as follows:

Period	(In millions)
2014	$963
2015	272
2016	254
2017	220
2018	136
Thereafter	719
Total	$2,564

Purchased Power Commitments

NRG has purchased power contracts of various quantities and durations that are not classified as derivative assets and liabilities and do not qualify as operating leases. These contracts are not included in the consolidated balance sheet as of December 31, 2013. Minimum purchase commitment obligations are as follows as of December 31, 2013:

Period	(In millions)
2014	$24
2015	18
2016	12
2017	10
2018	1
Thereafter	—
Total [(a)]	$65

(a) As of December 31, 2013, the maximum remaining term under any individual purchased power contract is five years.

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Lignite Contract with Texas Westmoreland Coal Co.

The lignite used to fuel the Texas region's Limestone facility is obtained from the Jewett mine, a surface mine adjacent to the Limestone facility, under a long-term contract with Texas Westmoreland Coal Co., or TWCC. The contract is based on a cost-plus arrangement with incentives and penalties to ensure proper management of the mine. NRG has the flexibility to increase or decrease lignite purchases from the mine within certain ranges, including the ability to suspend or terminate lignite purchases with adequate notice. The mining period extends through 2018 with an option to further extend the mining period by two five-year intervals.

TWCC is responsible for performing ongoing reclamation activities at the mine until all lignite reserves have been produced. When production is completed at the mine, NRG will be responsible for final mine reclamation obligations. The Railroad Commission of Texas has imposed a bond obligation of $107.5 million on TWCC for the reclamation of this lignite mine. Pursuant to the contract with TWCC, NRG supports this obligation as follows: $76 million is guaranteed by NRG Energy, Inc., and $31.5 million is supported by surety bonds posted by NRG. Additionally, NRG is required to provide additional performance assurance over TWCC's current bond obligations if required by the Railroad Commission of Texas.

First Lien Structure

NRG has granted first liens to certain counterparties on substantially all of the Company's assets, excluding assets acquired in the GenOn acquisition, to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or MWh equivalents. The Company's lien counterparties may have a claim on NRG's assets to the extent market prices exceed the hedged price. As of December 31, 2013, the first lien exposure of net out-of-the-money positions to counterparties on hedges was $61 million.

Nuclear Insurance

STP maintains required insurance coverage for liability claims arising from nuclear incidents pursuant to the Price-Anderson Amendment to the Energy Policy Act of 2005, referred to as the Price-Anderson Act. Effective September 30, 2013, the current liability limit per incident was $13.6 billion, subject to change to account for the effects of inflation and the number of licensed reactors. An inflation adjustment must be made at least once every five years with the most recent adjustment effective September 2013. Under the Price-Anderson Act, owners of nuclear power plants in the U.S. are required to purchase primary insurance limits of $375 million for each operating site. In addition, the Price-Anderson Act requires an additional layer of protection through mandatory participation in a retrospective rating plan for power reactors resulting in an additional $13.2 billion in funds available for public liability claims. The current maximum assessment per incident, per reactor, is approximately $127 million, taking into account a 5% adjustment for administrative fees, payable at no more than $19 million per year, per reactor. NRG would be responsible for 44% of the maximum assessment, or $8 million per year, per reactor, and a maximum of $112 million per incident. In addition, the U.S. Congress retains the ability to impose additional financial requirements on the nuclear industry to pay liability claims that exceed $13.6 billion for a single incident. The liabilities of the co-owners of STP with respect to the retrospective premium assessments for nuclear liability insurance are joint and several.

STP purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Limited, or NEIL, an industry mutual insurance company, of which STP is a member. STP has purchased $2.75 billion in limits for nuclear events and $1.5 billion in limits for non-nuclear events, the maximum available from NEIL. The upper $1 billion in limits (excess of the first $1.75 billion in limits) is a single limit blanket policy shared with two Diablo Canyon nuclear reactors, which have no affiliation with the Company. This shared limit is not subject to automatic reinstatement in the event of a loss. The NEIL policy covers both nuclear and non-nuclear property damage events, and includes coverage for six weeks of lost revenue following a property damage event, at a weekly indemnity limit of $4 million, subject to a seventeen week waiting period. NRG also purchased an Accidental Outage policy from NEIL, which provides protection for lost revenue due to an insurable event. This coverage allows for reimbursement up to $1.98 million per week per unit up to a maximum of $215.6 million nuclear and $144 million non-nuclear, and is subject to an eight week waiting period. Under the terms of the NEIL policies, member companies may be assessed up to ten times their annual premium if the NEIL Board of Directors determines their surplus has been depleted due to the payment of property losses at any of the licensed reactors in a single policy year. NEIL requires that its members maintain an investment grade credit rating or insure their annual retrospective obligation by providing a financial guarantee, letter of credit, deposit premium, or an insurance policy. NRG has purchased an insurance policy from NEIL to guarantee the Company's obligation; however this insurance will only respond to retrospective premium adjustments assessed within twenty-four months after the policy term, whereas NEIL's Board of Directors can make such an adjustment up to six years after the policy expires.

Contingencies

The Company's material legal proceedings are described below. The Company believes that it has valid defenses to these legal proceedings and intends to defend them vigorously. NRG records reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition, legal costs are expensed as incurred. Management has assessed each of the following matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, the Company is unable to predict the outcome of these legal proceedings or reasonably estimate the scope or amount of any associated costs and potential liabilities. As additional information becomes available, management adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of the Company's liabilities and contingencies could be at amounts that are different from its currently recorded reserves and that such difference could be material.

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect NRG's consolidated financial position, results of operations, or cash flows.

California Department of Water Resources

This matter concerned, among other contracts and other defendants, CDWR and its wholesale power contract with subsidiaries of WCP (Generation) Holdings, Inc., or WCP. The case originated with a 2002 complaint filed by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State of California. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, FERC rejected this complaint, denied rehearing, and the case was appealed to the U.S. Court of Appeals for the Ninth Circuit.

On December 19, 2006, the Ninth Circuit decided that in FERC's review of the contracts at issue, FERC could not rely on the Mobile-Sierra standard presumption of just and reasonable rates, where such contracts were not reviewed by FERC with full knowledge of the then existing market conditions. WCP and others sought review by the U.S. Supreme Court. WCP's appeal was not selected, but instead held by the Supreme Court. In the appeal that was selected by the Supreme Court, on June 26, 2008, the Supreme Court ruled: (i) that the Mobile-Sierra public interest standard of review applied to contracts made under a seller's market-based rate authority; (ii) that the public interest “bar” required to set aside a contract remains a very high one to overcome; and (iii) that the Mobile-Sierra presumption of contract reasonableness applies when a contract is formed during a period of market dysfunction unless (a) such market conditions were caused by the illegal actions of one of the parties or (b) the contract negotiations were tainted by fraud or duress.

This matter was extensively litigated and on March 22, 2012, NRG reached an agreement in principle with the CPUC to settle and resolve this matter, including all related claims, on behalf of NRG and on behalf of Dynegy. The settlement agreement contains three material elements to be fulfilled over a four to six year period, depending upon several factors. First, the settlement agreement includes a $20 million cash payment due 30 days after FERC approval. Second, it includes the construction and operation of a fee-based charging network, to be owned and operated by NRG subsidiary, eVgo, which will consist of at least 200 publicly available fast-charging electric vehicle stations installed at locations across California. Last, it calls for the wiring and associated work required to improve at least 10,000 individual parking spaces to allow for the charging of electric vehicles in at least 1,000 multi-family complexes, worksites, and public interest locations such as community colleges, public universities, and public or non-profit hospitals. Although these improved newly wired parking spaces will continue to be owned by the local property owner, eVgo will have an 18-month exclusive right to obtain customers from these locations starting from the date of each completed installation. The expected $20 million cash payment was accrued and expensed in the statement of operations for the three months ended March 31, 2012. In addition, the Company expects to spend approximately $100 million over the ensuing four to six year period, during which the Company will fulfill the other elements of the settlement, and will capitalize a substantial majority of the costs as property, plant and equipment, representing the costs to construct the charging network and the wiring, which will be productive assets. The Company will expense the costs to operate the assets as incurred. The documented agreement was executed and submitted to FERC on April 27, 2012 for its approval. The settlement agreement was approved by FERC on November 2, 2012. Final settlement payment of $20 million was made on January 16, 2013. Given that there was no challenge to the FERC order approving the settlement in the statutory period, the order became final and non-appealable.

Louisiana Generating, LLC
In 2009, the U.S. DOJ, on behalf of the EPA, and later the Louisiana Department of Environmental Quality, or LDEQ, on behalf of the State of Louisiana, sued Louisiana Generating, LLC, or LaGen, a wholly owned subsidiary of NRG, in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. On March 6, 2013, the court entered a Consent Decree resolving the matter. In addition to imposing a fine of $3.5 million and requiring LaGen to carry out mitigation projects totaling $10.5 million, the Consent Decree requires: (i) specified annual emission caps for NO_x and SO_2; (ii) installation of selective non-catalytic reduction on Units 1, 2 and 3 by May 1, 2014; (iii) installation of dry sorbent injection on Unit 1 by April 15, 2015 followed by a further reduction in SO_2 in March 2025; (iv) conversion of Unit 2 to natural gas; and (v) surrender of any excess allowances associated with the NRG owned portion of the plant. Further discussion of this matter can be found in Note 24, Environmental Matters - South Central Region.
In a related matter, soon after the filing of the above referenced U.S. DOJ lawsuit, LaGen sought insurance coverage from its insurance carrier, Illinois Union Insurance Company, or ILU. ILU denied coverage and refused to provide a defense for LaGen, and thereafter LaGen filed a lawsuit in federal district court in the Middle District of Louisiana (which was consolidated with a prior suit filed by ILU) seeking a declaration that ILU must provide coverage to LaGen for the defense costs incurred in defending the U.S. DOJ lawsuit as well as indemnity costs. LaGen and ILU both filed motions for summary judgment and on January 30, 2012, the district court issued an order granting LaGen's motion finding that ILU had a duty to defend LaGen. On May 25, 2012, ILU filed a petition with the U.S. Court of Appeals for the Fifth Circuit seeking to appeal the trial court's summary judgment ruling. The Fifth Circuit heard oral argument on March 6, 2013. On May 15, 2013, the Fifth Circuit affirmed the district court's ruling that ILU had a duty to defend LaGen against the U.S. DOJ lawsuit and subsequently denied ILU's petition for rehearing. On October 2, 2013, LaGen filed a motion for summary judgment in the U.S. District Court for the Middle District of Louisiana for recovery of LaGen's fees and costs related to the U.S. DOJ lawsuit, as well as its fees and costs related to the insurance coverage action.
Big Cajun II Alleged Opacity Violations — On September 7, 2012, LaGen received a Consolidated Compliance Order & Notice of Potential Penalty, or CCO&NPP, from the LDEQ. The CCO&NPP alleges there were opacity exceedance events from the Big Cajun II Power Plant on certain dates during the years 2007-2012. On October 8, 2012, LaGen filed a Request for Administrative Adjudicatory hearing. LaGen and LDEQ have since reached an agreement to resolve the matter for approximately $47,000. The settlement has been published for public comment, and is subject to approval by the Louisiana Attorney General within 90 days of the notice.
Global Warming
In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a suit in the U.S. District Court for the Northern District of California against GenOn and 23 other electric generating and oil and gas companies. The lawsuit sought damages of up to $400 million for the cost of relocating the village allegedly because of global warming caused by the GHG emissions of the defendants. In late 2009, the District Court ordered that the case be dismissed and the plaintiffs appealed. In September 2012, the U.S. Court of Appeals for the Ninth Circuit dismissed plaintiffs' appeal. In October 2012, the plaintiffs petitioned for en banc rehearing of the case, which petition was denied in November 2012. In February 2013, plaintiffs filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the U.S. Court of Appeals. In May 2013, the U.S. Supreme Court denied plaintiffs' petition, thereby ending the case.
Actions Pursued by MC Asset Recovery
With Mirant Corporation's emergence from bankruptcy protection in 2006, certain actions filed by GenOn Energy Holdings and some of its subsidiaries against third parties were transferred to MC Asset Recovery, a wholly owned subsidiary of GenOn Energy Holdings. MC Asset Recovery is governed by a manager who is independent of NRG and GenOn. MC Asset Recovery is a disregarded entity for income tax purposes.
Under the remaining action transferred to MC Asset Recovery, MC Asset Recovery seeks to recover damages from Commerzbank AG and various other banks, or the Commerzbank Defendants, for alleged fraudulent transfers that occurred prior to GenOn Energy Holdings' bankruptcy proceedings. In December 2010, the U.S. District Court for the Northern District of Texas dismissed MC Asset Recovery's complaint against the Commerzbank Defendants. In

January 2011, MC Asset Recovery appealed the District Court's dismissal of its complaint against the Commerzbank Defendants to the U.S. Court of Appeals for the Fifth Circuit. In March 2012, the Court of Appeals reversed the District Court's dismissal and reinstated MC Asset Recovery's amended complaint against the Commerzbank Defendants. If MC Asset Recovery succeeds in obtaining any recoveries from the Commerzbank Defendants, the Commerzbank Defendants have asserted that they will seek to file claims in GenOn Energy Holdings' bankruptcy proceedings for the amount of those recoveries. GenOn Energy Holdings would vigorously contest the allowance of any such claims. If the Commerzbank Defendants were to receive an allowed claim as a result of a recovery by MC Asset Recovery on its claims against them, GenOn Energy Holdings would retain from the net amount recovered by MC Asset Recovery an amount equal to the dollar amount of the resulting allowed claim.

Pending Natural Gas Litigation

GenOn is party to several lawsuits, certain of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada and Wisconsin. These lawsuits were filed in the aftermath of the California energy crisis in 2000 and 2001 and the resulting FERC investigations and relate to alleged conduct to increase natural gas prices in violation of antitrust and similar laws. The lawsuits seek treble or punitive damages, restitution and/or expenses. The lawsuits also name as parties a number of energy companies unaffiliated with NRG. In July 2011, the U.S. District Court for the District of Nevada, which is handling four of the five cases, granted the defendants' motion for summary judgment and dismissed all claims against GenOn in those cases. The plaintiffs appealed to the U.S. Court of Appeals for the Ninth Circuit. The Ninth Circuit reversed the decision of the U.S. District Court for the District of Nevada. On August 26, 2013, GenOn along with the other defendants in the lawsuit filed a petition for certiorari to the U.S. Supreme Court challenging the Ninth Circuit's decision. On December 2, 2013, the United States Supreme Court requested the views of the U.S. Solicitor General on the petition for certiorari. In September 2012, the State of Nevada Supreme Court, which is handling the remaining case, affirmed dismissal by the Eighth Judicial District Court for Clark County, Nevada of all plaintiffs' claims against GenOn. In February 2013, the plaintiffs in the Nevada case filed a petition for certiorari to the U.S. Supreme Court. In June 2013, the U.S. Supreme Court denied the petition for certiorari, thereby ending one of the five lawsuits. GenOn has agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

New Source Review Matters

The EPA and various states are investigating compliance of electric generating facilities with the pre-construction permitting requirements of the CAA known as "new source review." Since 2000, the EPA has made information requests concerning several of the Company's subsidiaries' plants. The Company continues to correspond with the EPA regarding some of these requests. The EPA agreed to share information relating to its investigations with state environmental agencies. In 2005 and 2006, the Company received an NOV from the EPA alleging that past work at Big Cajun II violated regulations regarding new source review. Further discussion of this matter can be found in Note 24, Environmental Matters - South Central Region. In January 2009, the EPA issued an NOV alleging that past work at the Shawville, Portland and Keystone generating facilities violated regulations regarding new source review. In June 2011, the EPA issued an NOV alleging that past work at the Niles and Avon Lake generating facilities violated regulations regarding new source review. In April 2013, the Connecticut Department of Energy and Environmental Protection issued four NOVs alleging that past work at combustion turbines at three of the Company's Connecticut Jet Power facilities and Middletown facility violated regulations regarding new source review.

In December 2007, the NJDEP sued GenOn in the U.S. District Court for the Eastern District of Pennsylvania, alleging that new source review violations occurred at the Portland generating facility. The suit sought installation of BACT for each pollutant, to enjoin GenOn from operating the generating facility if it is not in compliance with the CAA and civil penalties. The suit also named past owners of the plant as defendants, but the claims against the past owners were dismissed. In March 2009, the Connecticut Department of Energy and Environmental Protection became an intervening party to the suit. In July 2013, the court entered a Consent Decree which generally requires the cessation of coal combustion at Portland Units 1 and 2 and the payment of $1 million to benefit the environment in New Jersey and Connecticut. The entry of the Consent Decree resolved this matter.

Cheswick Class Action Complaint

In April 2012, a putative class action lawsuit was filed against GenOn in the Court of Common Pleas of Allegheny County, Pennsylvania alleging that emissions from the Cheswick generating facility have damaged the property of neighboring residents. The Company disputes these allegations. Plaintiffs have brought nuisance, negligence, trespass and strict liability claims seeking both damages and injunctive relief. Plaintiffs seek to certify a class that consists of people who own property or live within one mile of the Company's plant. In July 2012, the Company removed the lawsuit to the U.S. District Court for the Western District of Pennsylvania. In October 2012, the court granted the Company's motion to dismiss, which Plaintiffs appealed to the U.S. Court of Appeals for the Third Circuit. On August 20, 2013, the Third Circuit reversed the decision of the District Court. On September 3, 2013, the Company filed a petition for rehearing with the Third Circuit which was subsequently denied. In February 2014, the Company filed a petition for a writ of certiorari to the U.S. Supreme Court seeking review and reversal of the Third Circuit Decision.

The District Court has stayed further proceedings in the case pending a decision on the petition for writ of certiorari.

Cheswick Monarch Mine NOV

In 2008, the PADEP issued an NOV related to the Monarch mine located near the Cheswick generating facility. This mine has not been mined for many years. The Company uses it for disposal of low-volume wastewater from the Cheswick generating facility and for disposal of leachate collected from ash disposal facilities. The NOV addresses the alleged requirement to maintain a minimum pumping volume from the mine. The PADEP indicated it will seek a civil penalty of approximately $200,000. The Company contests the allegations in the NOV and has not agreed to such penalty. The Company is currently planning capital expenditures in connection with wastewater from Cheswick and leachate from ash disposal facilities.

Ormond Beach Alleged Federal Clean Water Act Violations

In October 2012, the Wishtoyo Foundation, a California-based cultural and environmental advocacy organization, through its Ventura Coastkeeper Program, filed suit in the U.S. District Court for the Central District of California regarding alleged violations of the CWA associated with discharges of stormwater from the Ormond Beach generating facility. The Wishtoyo Foundation alleged that elevated concentrations of pollutants in stormwater discharged from the Ormond Beach generating facility were affecting adjacent aquatic resources in violation of (i) the Statewide General Industrial Stormwater permit (a general National Pollution Discharge Elimination System permit issued by the California State Water Resources Control Board that authorizes stormwater discharges from industrial facilities in California) and (ii) the state's Porter-Cologne Water Quality Control Act. The Wishtoyo Foundation further alleged that the Company had not implemented effective stormwater control and treatment measures and that the Company had not complied with the sampling and reporting requirements of the General Industrial Stormwater permit. The Company settled this matter in May 2013 and agreed to make operational changes and pay $79,000 in legal fees, $65,000 for supplemental environmental projects, and $15,000 for monitoring costs.

Maryland Fly Ash Facilities

The Company has three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. Fly ash from the Morgantown and Chalk Point generating facilities is disposed of at Brandywine. Fly ash from the Dickerson generating facility is disposed of at Westland. Fly ash is no longer disposed of at the Faulkner facility. As described below, the MDE had sued NRG MD Ash Management and GenOn Mid-Atlantic regarding Faulkner, Brandywine and Westland. The MDE also had threatened not to renew the water discharge permits for all three facilities.

Faulkner Litigation — In May 2008, the MDE sued GenOn MidAtlantic and NRG MD Ash Management in the Circuit Court for Charles County, Maryland alleging violations of Maryland's water pollution laws at Faulkner. The MDE contended that the operation of Faulkner had resulted in the discharge of pollutants that exceeded Maryland's water quality criteria and without the appropriate NPDES permit. The MDE also alleged that GenOn failed to perform certain sampling and reporting required under an applicable NPDES permit. The MDE complaint requested that the court (i) prohibit continuation of the alleged unpermitted discharges, (ii) require GenOn to cease from further disposal of any coal combustion byproducts at Faulkner and close and cap the existing disposal cells and (iii) assess civil penalties. In July 2008, GenOn filed a motion to dismiss the complaint, arguing that the discharges are permitted by a December 2000 Consent Order. In January 2011, the MDE dismissed without prejudice its complaint and informed GenOn that it intended to file a similar lawsuit in federal court. In May 2011, the MDE filed a complaint against GenOn Mid-Atlantic and NRG MD Ash Management in the U.S. District Court for the District of Maryland alleging violations at Faulkner of the Clean Water Act and Maryland's Water Pollution Control Law. The MDE contends that (i) certain of GenOn's water discharges are not authorized by the existing permit and (ii) operation of the Faulkner facility has resulted in discharges of pollutants that violate water quality criteria. The complaint asked the court to, among other things, (i) enjoin further disposal of coal ash; (ii) enjoin discharges that are not authorized by the existing permit; (iii) require numerous technical studies; (iv) impose civil penalties and (v) award MDE attorneys' fees. The Company disputed these allegations.

Brandywine Litigation — In April 2010, the MDE filed a complaint against GenOn MidAtlantic and NRG MD Ash Management in the U.S. District Court for the District of Maryland asserting violations at Brandywine of the CWA and Maryland's Water Pollution Control Law. The MDE contended that the operation of Brandywine has resulted in discharges of pollutants that violate Maryland's water quality criteria. The complaint requested that the court, among other things, (i) enjoin further disposal of coal combustion waste at Brandywine, (ii) require the existing open disposal cells to be closed and capped within one year, (iii) impose civil penalties, and (iv) award MDE attorneys' fees. In September 2010, four environmental advocacy groups became intervening parties in the proceeding.

Westland Litigation — In January 2011, the MDE informed GenOn that it intended to sue for alleged violations at Westland of Maryland's water pollution laws, which suit was filed in U.S. District Court for the District of Maryland in December 2012.

Permit Renewals — In March 2011, the MDE tentatively decided to deny NRG MD Ash Management's application for renewal of the water discharge permit for Brandywine, which could have resulted in a significant increase in operating expenses for GenOn Mid Atlantic's Chalk Point and Morgantown generating facilities. The MDE also had indicated that it was planning to deny the Company's applications for renewal of the water discharge permits for Faulkner and Westland. Denial of the renewal of the water discharge permit for the latter facility could have resulted in a significant increase in operating expenses for the Dickerson generating facility.

Settlement — In April 2013, NRG MD Ash Management and MDE signed a Consent Decree settling the disputes at each of the three ash facilities. GenOn agreed to pay a civil penalty of $1.9 million for alleged past violations and an additional $0.6 million (for agreed prospective penalties while the settlement is implemented). GenOn agreed to develop a technical solution, which includes installing synthetic caps on the closed cells of each of the three ash facilities, for which $47 million has been reserved, and to remediate the site. At this time, the Company cannot reasonably estimate the upper range of its obligation for remediating the sites because the Company has not: (i) finished assessing each site including identifying the full impacts to both ground and surface water and the impacts to the surrounding habitat; (ii) finalized with the MDE the standards to which it must remediate; and (iii) identified the technologies required, if any, to meet the yet to be determined remediation standards at each site nor the timing of the design and installation of such technologies.

Energy Plus Holdings Purported Class Actions

Energy Plus Holdings was sued in six purported class action lawsuits, two in New York, two in New Jersey, and two in Pennsylvania. On February 28, 2013, Energy Plus Holdings entered into a settlement agreement with plaintiffs to resolve all of the claims in the six pending suits, subject to court approval. On September 17, 2013, the U.S. District Court for the Southern District of New York entered an order approving the settlement. This settlement became final and nonappealable on October 27, 2013. Energy Plus Holdings continues to cooperate with the Connecticut Office of Attorney General and Office of Consumer Counsel and the State of New York Office of Attorney General to resolve certain issues related to Energy Plus Holdings sales, marketing and business practices. Energy Plus Holdings and the Connecticut Office of Attorney General and Office of Consumer Counsel have been involved in settlement discussions and their efforts to reach a resolution continue.

Purported Class Actions related to July 22, 2012 Announcement of NRG/GenOn Merger Agreement

NRG was named as a defendant in eight purported class actions in Texas and Delaware related to its announcement of its agreement to acquire all outstanding shares of GenOn. These cases were consolidated into one state court case in each of Delaware and Texas and a federal court case in Texas. The plaintiffs generally alleged breach of fiduciary duties, as well as conspiracy, aiding and abetting breaches of fiduciary duties. Plaintiffs generally sought to: be certified as a class; enjoin the merger; direct the defendants to exercise their fiduciary duties; rescind the acquisition; and be awarded attorneys' fees costs and other relief that the court deems appropriate. Plaintiffs also demanded that there be additional disclosures regarding the merger terms. On October 24, 2012, the parties to the Delaware state court case executed a Memorandum of Understanding to resolve the Delaware purported class action lawsuit. In March 2013, the parties finalized the settlement of the Delaware action. On June 3, 2013, the court approved the Delaware class action settlement thereby ending the Delaware lawsuit. The remaining Texas state and federal court cases were dismissed in July 2013 and August 2013, respectively, thereby ending these matters.

Maryland Department of the Environment v. GenOn Chalk Point and GenOn Mid-Atlantic

On January 25, 2013, Food & Water Watch, the Patuxent Riverkeeper and the Potomac Riverkeeper (together, the Citizens Group) sent NRG a letter alleging that the Chalk Point, Dickerson and Morgantown generating facilities were violating the terms of the three National Pollution Discharge Elimination System permits by discharging nitrogen and phosphorous in excess of the limits in each permit. On March 21, 2013, the MDE sent the Company a similar letter with respect to the Chalk Point and Dickerson facilities, threatening to sue within 60 days if the Company did not bring itself into compliance. On June 11, 2013, the Maryland Attorney General on behalf of the MDE filed a complaint in the U.S. District Court for the District of Maryland alleging violations of the Clean Water Act and Maryland environmental laws related to water. The lawsuit seeks injunctive relief and civil penalties in excess of $100,000.

Huntley Power LLC Subpoena

Huntley Power LLC was served with a subpoena on May 13, 2013 from the U.S. Department of Justice requesting information regarding the plant's use and handling of diesel fuel. The Company cooperated with the U.S Department of Justice inquiry into the issues related to the use and handling of diesel fuel. The U.S. Department of Justice has advised that it is not pursuing information related to this subpoena and has closed its file, thereby ending the matter.

Texas Franchise Audit

During the second quarter of 2013, the Company settled the Texas Franchise tax dispute with the state relating to years 2001 through 2007. Prior to the GenOn acquisition, the State of Texas issued franchise tax assessments against GenOn as a result of its audit indicating an underpayment of franchise tax of $72 million (including interest and penalties through June 30, 2013 of $29 million). These assessments relate primarily to a claim by Texas that would change the sourcing of intercompany receipts thereby increasing the amount of tax due. GenOn disagreed with most of the State's assessment and its determination and had accordingly accrued a portion of the liability but had protested the entire assessment. In June 2013, the Company settled the matter with the State by agreeing to pay $11 million on issues arising from the audit, and reversed the remainder of the accrual. The reversal was recorded as a measurement period adjustment to the amounts recognized on the acquisition date.

Note 23 — Regulatory Matters
NRG operates in a highly regulated industry and is subject to regulation by various federal and state agencies. As such, NRG is affected by regulatory developments at both the federal and state levels and in the regions in which NRG operates. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO and RTO markets in which NRG participates. These power markets are subject to ongoing legislative and regulatory changes that may impact NRG's wholesale and retail businesses.
In addition to the regulatory proceedings noted below, NRG and its subsidiaries are a party to other regulatory proceedings arising in the ordinary course of business or have other regulatory exposure. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect NRG's consolidated financial position, results of operations, or cash flows.
East Region
Reliability Must Run Agreements for Elrama and Niles — In May 2012, GenOn filed with FERC an RMR rate schedule governing operation of unit 4 of the Elrama generating facility and unit 1 of the Niles generating facility. PJM determined that each of these units was needed past its planned deactivation date of June 1, 2012 to maintain transmission system reliability on the PJM system pending the completion of transmission upgrades. The RMR rate schedule sets forth the terms, conditions and cost-based rates under which GenOn operated the units for reliability purposes through September 30, 2012, the date PJM indicated the units would no longer be needed for reliability. In July 2012, FERC accepted GenOn's RMR rate schedule subject to hearing and settlement procedures. In the settlement discussions ordered by FERC, or in any subsequent hearing, the Company's RMR rate schedule may be modified from that which was filed. The rates GenOn charged are subject to refund pending a ruling or settlement. The Company filed a settlement of all outstanding issues in May 2013, which several parties are contesting. The matter is pending before FERC.
Montgomery County Station Power Tax — On December 20, 2013, the Company received a letter from Montgomery County, Maryland requesting payment of an energy tax for the consumption of station power at the Dickerson Facility over the last three years. The letter seeks payment in the amount of $14.6 million, which includes tax, interest and penalty. The Company is disputing the applicability of the tax and GenOn Mid-Atlantic, LLC filed suit against the County in Maryland Tax Court and the Circuit Court for Montgomery County on January 21, 2014. The parties jointly filed on February 25, 2014, to stay the Circuit Court proceeding pending resolution of the Tax Court proceeding. The Tax Court proceeding is still pending.
Retail
MISO SECA — Green Mountain Energy previously provided competitive retail energy supply in the MISO region during the relevant period of January 1, 2002, to December 31, 2005. By order dated November 18, 2004, FERC eliminated certain regional through-and-out transmission rates charged by transmission owners in MISO and PJM. In order to temporarily compensate the transmission owners for lost revenues, FERC ordered MISO, PJM and their respective transmission owners to revamp the way that ISOs manage certain cross-system congestion costs, known as Seams Elimination Charge/Cost Adjustments/Assignments, or SECA, charges effective December 1, 2004, through March 31, 2006. The tariff amendments filed by MISO and the MISO transmission owners allocated certain SECA charges to various zones and sub-zones within MISO, including a sub-zone called the Green Mountain Energy Company Sub-zone. During several years of extensive litigation before FERC, several transmission owners sought to recover SECA charges from Green Mountain Energy. Green Mountain Energy denied responsibility for any SECA charges and did not pay any asserted SECA charges.
On May 21, 2010, FERC issued two orders, including its Order on Initial Decision, in which FERC determined that approximately $22 million plus interest of SECA charges were owed not by Green Mountain Energy but rather by BP Energy - one of Green Mountain Energy's suppliers during the period at issue. On August 19, 2010, the transmission owners and MISO made compliance filings in accordance with FERC's Orders allocating SECA charges to a BP Energy Sub-zone, and making no allocation to a Green Mountain Energy sub-zone. FERC has not yet ruled on those compliance filings.
On September 30, 2011, FERC issued orders denying all requests for rehearing and again determined that SECA charges were not owed by Green Mountain Energy. Numerous parties, including BP Energy, sought judicial review

of FERC's orders, and Green Mountain Energy was granted intervenor status in the consolidated appeals. Most appellants subsequently settled with the transmission owners and withdrew their appeals, including BP Energy, which agreed to pay approximately $24 million to the three transmission owners signing the agreement, with another $1 million offered to the remaining PJM transmission owners, should they choose to join the settlement; all chose to do so. FERC approved the settlement, and BP Energy moved to dismiss its appeals; its motions to dismiss were granted by the Court.

West Region

California Station Power — On December 18, 2012, in Calpine Corporation v. FERC, the U.S. Court of Appeals for the D.C. Circuit upheld a decision by FERC disclaiming jurisdiction over how the states impose retail station power charges. The CPUC may now establish retail charges for future station power consumption. Due to reservation-of-rights language in the California utilities' state-jurisdictional station power tariffs, the court's ruling arguably requires California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO's station power program (February 1, 2009, for the Company's Encina and El Segundo facilities; March 1, 2009, for the Company's Long Beach facility).

On November 18, 2011, Southern California Edison Company filed with the CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively, which the Company and other generators have challenged. On August 13, 2012, the CPUC Energy Division issued a draft resolution in which it rejected the Company's arguments and approved Southern California Edison's proposed station power charges, including retroactive implementation, but proposing a credit to generators for some portion of their retail station power bill. However, the CPUC withdrew the draft resolution from the calendar and consideration of the measure has not yet been rescheduled. The Company believes it has established an appropriate reserve.

Note 24 — Environmental Matters

NRG is subject to a wide range of environmental regulations in the development, ownership, construction and operation of projects in the United States and Australia. These laws and regulations generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental regulations have become increasingly stringent and NRG expects this trend to continue. The electric generation industry is likely to face new requirements to address various emissions, including greenhouse gases, as well as combustion byproducts, water discharge and use, and threatened and endangered species. In general, future laws and regulations are expected to require the addition of emissions controls or other environmental controls or to impose certain restrictions on the operations of the Company's facilities, which could have a material effect on the Company's operations.

The EPA released CSAPR on July 7, 2011, which was scheduled to replace CAIR on January 1, 2012. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating CSAPR and keeping CAIR in place until the EPA can replace it. The EPA petitioned the U.S. Supreme Court seeking review of this decision, which petition was granted. The Supreme Court heard oral argument in the case on December 10, 2013. The Court of Appeals decision was beneficial to the Company as it eliminated an SO_2 allowance reduction which was to have occurred before the MATS compliance date. While NRG is unable to predict the final outcome of the ongoing litigation, the Company's investment in pollution controls and cleaner technologies coupled with planned strategic plant retirements leaves the fleet well positioned for compliance.

Under CSAPR, use of discounted Acid Rain SO_2 and CAIR NO_x allowances would have been discontinued and replaced with completely distinct allowance programs. Acid Rain allowances would still be required on a 1:1 basis under the Acid Rain Program. Consequently, in the third quarter 2011, the Company recorded an impairment charge of $160 million on the Company's Acid Rain Program SO_2 emission allowances, which were recorded as an intangible asset on the Company's balance sheet. The impairment charge reflects the write-off of the value of emission allowances in excess of those required for compliance with the Acid Rain Program.

In January 2014, EPA re-proposed the NSPS for CO_2 emissions from new fossil-fuel-fired electric generating units that had been previously proposed in April 2012. The re-proposed standards are 1,000 pounds of CO_2 per MWh for large gas units and 1,100 pounds of CO_2 per MWh for coal units and small gas units. Proposed standards are in effect until a final rule is published or another rule is re-proposed. In 2014, EPA intends to propose another rule that would require states to develop CO_2 standards that would apply to existing fossil-fueled generating facilities.

Environmental Capital Expenditures

Based on current (and in some cases proposed) rules, technology and preliminary plans based on some proposed rules, NRG estimates that environmental capital expenditures from 2014 through 2018 required to comply with environmental laws will be approximately $332 million, which includes $120 million for GenOn. These costs are primarily associated with (i) controls to satisfy MATS and the recent NSR settlement at Big Cajun II; (ii) controls to satisfy MATS at W.A. Parish, Limestone and Conemaugh; and (iii) NO_x controls for Sayreville and Gilbert. NRG continues to explore cost-effective compliance alternatives to further reduce costs.

NRG's contracts with its rural electric cooperative customers in the South Central region allow for recovery of a portion of the region's environmental capital costs incurred as the result of complying with any change in environmental law. Cost recoveries begin once the environmental equipment becomes operational and include a return on capital. The actual recoveries will depend, among other things, on the timing of the completion of the capital projects and the remaining duration of the contracts.

East Region

The EPA and various states are investigating compliance of electric generating facilities with the pre-construction permitting requirements of the CAA known as "new source review," or NSR. In January 2009, GenOn received an NOV from the EPA alleging that past work at Keystone, Portland and Shawville generating facilities violated regulations regarding NSR. In June 2011, GenOn received an NOV from the EPA alleging that past work at Avon Lake and Niles generating stations violated NSR. In December 2007, the NJDEP filed suit alleging that NSR violations occurred at the Portland generating station, which suit was resolved pursuant to a July 2013 Consent Decree. The Shawville and Portland generating units that are the subject of the NOVs are scheduled for retirement soon. The Niles coal generating unit, also subject to the NOV, was retired in 2012. Additionally, in April 2013, the Connecticut Department of Energy and Environmental Protection issued four NOVs alleging that past work at oil-fired combustion turbines at the Torrington Terminal, Franklin, Branford and Middletown violated regulations regarding NSR.

In 2008, the PADEP issued an NOV related to the inactive Monarch mine where low-volume wastewater from the Cheswick Generating Station and ash leachate was historically disposed. Resolution of the NOV could result in operational requirements such as pumping a minimum volume of water from the mine and a penalty of approximately $200,000.

In January 2006, NRG's Indian River Operations, Inc. was notified that it may be a potentially responsible party with respect to Burton Island Old Ash Landfill, a historic captive landfill located at the Indian River facility. On October 1, 2007, NRG signed an agreement with DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, DNREC issued findings that no further action is required in relation to surface water and that a previously planned shoreline stabilization project would satisfactorily address shoreline erosion. The landfill itself required a Remedial Investigation and Feasibility Study to determine the type and scope of any additional required work. The DNREC approved the Feasibility Study in December 2012. In January 2013, DNREC proposed a remediation plan based on the Feasibility Study. The remediation plan was approved in October 2013. The cost of completing the work required by the approved remediation plan is consistent with amounts previously budgeted. On May 29, 2008, DNREC requested that NRG's Indian River Operations, Inc. participate in the development and performance of a Natural Resource Damage Assessment at the Burton Island Old Ash Landfill. NRG is currently working with DNREC and other trustees to close out the assessment process.

The MDE sued GenOn for alleged violations of water pollution laws at three fly ash disposal sites in Maryland: Faulkner (2008/2011), Brandywine (2010) and Westland (2012). On April 30, 2013, the court approved the consent decree resolving these issues. GenOn has discontinued use of the Faulkner disposal site and opened a new, state of the art carbon burnout facility at its Morgantown plant that allows greater beneficial reuse (as a cement substitute).

In addition, the MDE has announced that it intends to promulgate more stringent regulations regarding NO_x emissions, which could negatively affect certain of the Company's coal facilities located in Maryland.

In 2013, each of the RGGI member states finalized a rule that collectively reduced the CO_2 emissions cap from 165 million tons to 91 million tons in 2014 with a 2.5% reduction each year from 2015 to 2020. The Company expects earnings at its plants in Massachusetts, New York, and particularly those in Maryland, to be negatively affected. The extent to which the Company would be negatively affected depends on the price of the CO_2 emissions allowances, which in turn will be significantly influenced by future natural gas prices, power prices, generation resource mix, dispatch order, and any nuclear plant retirements.

For further discussion of these matters, refer to Note 22, Commitments and Contingencies.

South Central Region

In 2009, the U.S. DOJ, on behalf of the EPA, and later the Louisiana Department of Environmental Quality on behalf of the state of Louisiana, sued LaGen in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. On March 6, 2013, the court entered a Consent Decree resolving the matter.

In addition to a fine of $3.5 million and mitigation projects totaling $10.5 million the Consent Decree includes: (i) annual emission caps for NO_x and SO_2; (ii) installation of selective non-catalytic reduction on Units 1, 2 and 3 by May 1, 2014; (iii) installation of dry sorbent injection on Unit 1 by April 15, 2015 followed by a further reduction in SO_2 in March 2025; (iv) conversion of Unit 2 to natural gas; and (v) surrender of any excess allowances associated with the NRG owned portion of the plant. For further discussion of this matter, refer to Note 22, Commitments and Contingencies.

Note 25 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Interest paid, net of amount capitalized	$836	$579	$642
Income taxes (refunded)/paid [(a)]	(60)	17	26
Non-cash investing and financing activities:			
Additions to fixed assets for accrued capital expenditures	405	563	292
Decrease to fixed assets for accrued grants and related tax impact	(681)	(87)	(32)
Decrease to notes receivable for equity conversion	—	—	63
Issuance of shares for GenOn acquisition	—	(2,188)	—

(a) In 2013, the net income taxes refunded are net of $28 million income taxes paid and $87 million income tax refunds. No tax refunds were received in 2012. In 2011, income taxes paid are net of $8 million of income tax refunds received.

Note 26 — Guarantees

NRG and its subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of the Company's business activities. Examples of these contracts include asset purchases and sale agreements, commodity sale and purchase agreements, retail contracts, joint venture agreements, EPC agreements, operation and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. The Company is obligated with respect to customer deposits associated with the Retail Business. NRG has also assumed guarantees for some non-qualified benefits of existing retirees resulting from the acquisition of GenOn. In some cases, NRG's maximum potential liability cannot be estimated, since the underlying agreements contain no limits on potential liability.

In accordance with ASC 460, Guarantees, or ASC 460, NRG has estimated that the current fair value for issuing these guarantees was $5.4 million as of December 31, 2013, and the liability in this amount is included in the Company's non-current liabilities.

The following table summarizes the maximum potential exposures that can be estimated for NRG's guarantees, indemnities, and other contingent liabilities by maturity:

	By Remaining Maturity at December 31, 2013					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2012 Total
	(In millions)					
Letters of credit and surety bonds	$1,654	$47	$—	$—	$1,701	$1,594
Asset sales guarantee obligations	—	—	275	—	275	275
Commercial sales arrangements	81	112	23	1,338	1,554	1,579
Other guarantees	78	4	—	469	551	356
Total guarantees	$1,813	$163	$298	$1,807	$4,081	$3,804

Letters of credit and surety bonds — As of December 31, 2013, NRG and its consolidated subsidiaries were contingently obligated for a total of $1.8 billion under letters of credit and surety bonds. Most of these letters of credit and surety bonds are issued in support of the Company's obligations to perform under commodity agreements and in support of equity contribution requirements for solar projects in construction, as well as for financing or other arrangements. A majority of these letters of credit and surety bonds expire within one year of issuance, and it is typical for the Company to renew them on similar terms.

The material indemnities, within the scope of ASC 460, are as follows:
Asset purchases and divestitures — The purchase and sale agreements which govern NRG's asset or share investments and divestitures customarily contain guarantees and indemnifications of the transaction to third parties. The contracts indemnify the parties for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party, or as a result of a change in tax laws. These obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or estimate at the time of the transaction. In several cases, the contract limits the liability of the indemnifier. NRG has no reason to believe that the Company currently has any material liability relating to such routine indemnification obligations.
Commercial sales arrangements — In connection with the purchase and sale of fuel, emission allowances and power generation products to and from third parties with respect to the operation of some of NRG's generation facilities in the United States, the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments.
Other guarantees — NRG has issued guarantees of obligations that its subsidiaries may incur as a provision for environmental site remediation, payment of debt obligations, rail car leases, performance under purchase, EPC and operating and maintenance agreements. The Company does not believe that it will be required to perform under these guarantees.
Other indemnities — Other indemnifications NRG has provided cover operational, tax, litigation and breaches of representations, warranties and covenants. NRG has also indemnified, on a routine basis in the ordinary course of business, consultants or other vendors who have provided services to the Company. NRG's maximum potential exposure under these indemnifications can range from a specified dollar amount to an indeterminate amount, depending on the nature of the transaction. Total maximum potential exposure under these indemnifications is not estimable due to uncertainty as to whether claims will be made or how they will be resolved. NRG does not have any reason to believe that the Company will be required to make any material payments under these indemnity provisions.
Because many of the guarantees and indemnities NRG issues to third parties and affiliates do not limit the amount or duration of its obligations to perform under them, there exists a risk that the Company may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit the Company's liability exposure, it may not be able to estimate what the Company's liability would be, until a claim is made for payment or performance, due to the contingent nature of these contracts.
Note 27 — Jointly Owned Plants
Certain NRG subsidiaries own undivided interests in jointly-owned plants, as described below. These plants are maintained and operated pursuant to their joint ownership participation and operating agreements. NRG is responsible for its subsidiaries' share of operating costs and direct expenses and includes its proportionate share of the facilities and related revenues and direct expenses in these jointly-owned plants in the corresponding balance sheet and income statement captions of the Company's consolidated financial statements.
The following table summarizes NRG's proportionate ownership interest in the Company's jointly-owned facilities:

As of December 31, 2013	Ownership Interest		Property, Plant & Equipment	Accumulated Depreciation		Construction in Progress
	(In millions unless otherwise stated)					
South Texas Project Units 1 and 2, Bay City, TX	44.00	%	$2,679	$(1,293	)	$19
Big Cajun II Unit 3, New Roads, LA	58.00	%	178	(95	)	18
Cedar Bayou Unit 4, Baytown, TX	50.00	%	215	(49	)	—
Keystone, Shelocta, PA	3.70	%	92	(35	)	1
Conemaugh, New Florence, PA	3.72	%	82	(38	)	14

Note 28 — Unaudited Quarterly Financial Data

Refer to Note 3, Business Acquisitions and Dispositions, and Note 10, Asset Impairments, for a description of the effect of unusual or infrequently occurring events during the quarterly periods. Summarized unaudited quarterly financial data is as follows:

	Quarter Ended 2013			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$2,795	$3,490	$2,930	$2,081
Operating (loss)/income	(205)	527	287	(266)
Net (loss)/income	(283)	$135	130	(334)
Net (loss)/income attributable to NRG Energy, Inc.	$(290)	$116	$122	$(334)
Weighted average number of common shares outstanding — basic	323	323	323	323
Net (loss)/income per weighted average common share — basic	$(0.90)	$0.36	$0.38	$(1.03)
Weighted average number of common shares outstanding — diluted	323	327	327	323
Net (loss)/income per weighted average common share — diluted	$(0.90)	$0.35	$0.37	$(1.03)

	Quarter Ended 2012			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$2,063	$2,331	$2,166	$1,862
Operating income/(loss)	37	86	397	(170)
Net income/(loss)	254	8	259	(206)
Net income/(loss) attributable to NRG Energy, Inc.	$252	$(1)	$251	$(207)
Weighted average number of common shares outstanding — basic	247	228	228	228
Net income/(loss) per weighted average common share — basic	$1.02	$(0.01)	$1.09	$(0.92)
Weighted average number of common shares outstanding — diluted	249	228	229	228
Net income/(loss) per weighted average common share — diluted	$1.01	$(0.01)	$1.08	$(0.92)

Note 29 — Condensed Consolidating Financial Information
As of December 31, 2013, the Company had outstanding $5.7 billion of Senior Notes due 2018 - 2023, as shown in Note 12, Debt and Capital Leases. These Senior Notes are guaranteed by certain of NRG's current and future 100% owned domestic subsidiaries, or guarantor subsidiaries. These guarantees are both joint and several. The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries, including GenOn and its subsidiaries.
Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 31, 2013:

Ace Energy, Inc.	Middletown Power LLC	NRG Oswego Harbor Power Operations Inc.
Allied Warranty LLC	Montville Power LLC	NRG PacGen Inc.
Allied Home Warranty GP LLC	NEO Corporation	NRG Power Marketing LLC
Arthur Kill Power LLC	NEO Freehold-Gen LLC	NRG Reliability Solutions LLC
Astoria Gas Turbine Power LLC	NEO Power Services Inc.	NRG Renter's Protection LLC
BidURenergy, Inc.	New Genco GP, LLC	NRG Retail LLC
Cabrillo Power I LLC	Norwalk Power LLC	NRG Retail Northeast LLC
Cabrillo Power II LLC	NRG Affiliate Services Inc.	NRG Rockford Acquisition LLC
Carbon Management Solutions LLC	NRG Artesian Energy LLC	NRG Saguaro Operations Inc.
Clean Edge Energy LLC	NRG Arthur Kill Operations Inc.	NRG Security LLC
Conemaugh Power LLC	NRG Astoria Gas Turbine Operations Inc.	NRG Services Corporation
Connecticut Jet Power LLC	NRG Bayou Cove LLC	NRG SimplySmart Solutions LLC
Cottonwood Development LLC	NRG Cabrillo Power Operations Inc.	NRG South Central Affiliate Services Inc.
Cottonwood Energy Company LP	NRG California Peaker Operations LLC	NRG South Central Generating LLC
Cottonwood Generating Partners I LLC	NRG Cedar Bayou Development Company, LLC	NRG South Central Operations Inc.
Cottonwood Generating Partners II LLC	NRG Connecticut Affiliate Services Inc.	NRG South Texas LP
Cottonwood Generating Partners III LLC	NRG Construction LLC	NRG Texas C&I Supply LLC
Cottonwood Technology Partners LP	NRG Curtailment Solutions LLC	NRG Texas Gregory LLC
Devon Power LLC	NRG Development Company Inc.	NRG Texas Holding Inc.
Dunkirk Power LLC	NRG Devon Operations Inc.	NRG Texas LLC
Eastern Sierra Energy Company LLC	NRG Dispatch Services LLC	NRG Texas Power LLC
El Segundo Power, LLC	NRG Dunkirk Operations Inc.	NRG Unemployment Protection LLC
El Segundo Power II LLC	NRG El Segundo Operations Inc.	NRG Warranty Services LLC
Elbow Creek Wind Project LLC	NRG Energy Labor Services LLC	NRG West Coast LLC
Energy Alternatives Wholesale, LLC	NRG Energy Services Group LLC	NRG Western Affiliate Services Inc.
Energy Curtailment Specialists, Inc.	NRG Energy Services International Inc.	O'Brien Cogeneration, Inc. II
Energy Plus Holdings LLC	NRG Energy Services LLC	ONSITE Energy, Inc.
Energy Plus Natural Gas LLC	NRG Generation Holdings, Inc.	Oswego Harbor Power LLC
Energy Protection Insurance Company	NRG Home & Business Solutions LLC	RE Retail Receivables, LLC
Everything Energy LLC	NRG Home Solutions LLC	Reliant Energy Northeast LLC
GCP Funding Company, LLC	NRG Home Solutions Product LLC	Reliant Energy Power Supply, LLC
Green Mountain Energy Company	NRG Homer City Services LLC	Reliant Energy Retail Holdings, LLC

Green Mountain Energy Company (NY Com) LLC	NRG Huntley Operations Inc.	Reliant Energy Retail Services, LLC
	NRG Identity Protect LLC	RERH Holdings LLC
Green Mountain Energy Company (NY Res) LLC	NRG Ilion Limited Partnership	Saguaro Power LLC
	NRG Ilion LP LLC	Somerset Operations Inc.
Gregory Partners, LLC	NRG International LLC	Somerset Power LLC
Gregory Power Partners LLC	NRG Maintenance Services LLC	Texas Genco Financing Corp.
Huntley Power LLC	NRG Mextrans Inc.	Texas Genco GP, LLC
Independence Energy Alliance LLC	NRG MidAtlantic Affiliate Services Inc.	Texas Genco Holdings, Inc.
Independence Energy Group LLC	NRG Middletown Operations Inc.	Texas Genco LP, LLC
Independence Energy Natural Gas LLC	NRG Montville Operations Inc.	Texas Genco Operating Services, LLC
Indian River Operations Inc.	NRG New Jersey Energy Sales LLC	Texas Genco Services, LP
Indian River Power LLC	NRG New Roads Holdings LLC	US Retailers LLC
Keystone Power LLC	NRG North Central Operations Inc.	Vienna Operations Inc.
Langford Wind Power, LLC	NRG Northeast Affiliate Services Inc.	Vienna Power LLC
Lone Star A/C & Appliance Repairs, LLC	NRG Norwalk Harbor Operations Inc.	WCP (Generation) Holdings LLC
Louisiana Generating LLC	NRG Operating Services, Inc.	West Coast Power LLC
Meriden Gas Turbines LLC		

The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries, including GenOn and its subsidiaries. NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company's ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG's ability to receive funds from its subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under the Company's Peaker financing agreements, there are no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to NRG. In addition, there may be restrictions for certain non-guarantor subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities.

In this presentation, NRG Energy, Inc. consists of parent company operations. Guarantor subsidiaries and non-guarantor subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

In addition, the condensed parent company financial statements are provided in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of NRG Energy, Inc.’s subsidiaries exceed 25 percent of the consolidated net assets of NRG Energy, Inc. These statements should be read in conjunction with the consolidated statements and notes thereto of NRG Energy, Inc. For a discussion of NRG Energy, Inc.'s long-term debt, see Note 12, Debt and Capital Leases to the consolidated financial statements. For a discussion of NRG Energy, Inc.'s contingencies, see Note 22, Commitments and Contingencies to the consolidated financial statements. For a discussion of NRG Energy, Inc.'s guarantees, see Note 26, Guarantees to the consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2013

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
	(In millions)				
Operating Revenues					
Total operating revenues	$8,223	$ 3,211	$—	$ (139)	$ 11,295
Operating Costs and Expenses					
Cost of operations	6,150	2,104	—	(133)	8,121
Depreciation and amortization	837	407	12		1,256
Impairment losses	459	—	—	—	459
Selling, general and administrative	446	230	234	(6)	904
Acquisition-related transaction and integration costs	—	70	58	—	128
Development activity expenses	—	34	50	—	84
Total operating costs and expenses	7,892	2,845	354	(139)	10,952
Operating Income/(Loss)	331	366	(354)	—	343
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	(67)	(14)	221	(140)	—
Equity in earnings/(losses) of unconsolidated affiliates	(11)	22	—	(4)	7
Impairment charge on investment	—	(99)		—	(99)
Other income, net	6	11	(2)	(2)	13
Loss on debt extinguishment		(12)	(38)	—	(50)
Interest expense	(24)	(318)	(506)	—	(848)
Total other income/(expense)	(96)	(410)	(325)	(146)	(977)
Income/(Loss) Before Income Taxes	235	(44)	(679)	(146)	(634)
Income tax expense/(benefit)	114	(89)	(307)	—	(282)
Net Income	121	45	(372)	(146)	(352)
Less: Net income attributable to noncontrolling interest	—	27	13	(6)	34
Net Income attributable to NRG Energy, Inc	$121	$ 18	$(385)	$ (140)	$ (386)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME
For the Year Ended December 31, 2013

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income	$121	$45	$(372)	$(146)	$(352)
Other comprehensive (loss)/income, net of tax					
Unrealized loss on derivatives, net	(71)	50	120	(91)	8
Foreign currency translation adjustments, net	—	(20)	(4)	—	(24)
Available-for-sale securities, net	—	—	3	—	3
Defined benefit plan, net	75	63	30	—	168
Other comprehensive loss	4	93	149	(91)	155
Comprehensive income	125	138	(223)	(237)	(197)
Less: Comprehensive income attributable to noncontrolling interest	—	27	13	(6)	34
Comprehensive income attributable to NRG Energy, Inc.	125	111	(236)	(231)	(231)
Dividends for preferred shares	—	—	9	—	9
Comprehensive income available for common stockholders	$125	$111	$(245)	$(231)	$(240)

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2013

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
	(In millions)				
ASSETS					
Current Assets					
Cash and cash equivalents	$56	$ 870	$1,328	$ —	$ 2,254
Funds deposited by counterparties	7	56	—	—	63
Restricted cash	12	252	4	—	268
Accounts receivable - trade, net	965	249	—	—	1,214
Inventory	436	462	—	—	898
Derivative instruments	866	470	—	(8)	1,328
Deferred income taxes	—	41	217	—	258
Cash collateral paid in support of energy risk management activities	214	62	—	—	276
Renewable energy grant receivable	—	539	—	—	539
Prepayments and other current assets	4,778	379	(3,802)	(857)	498
Total current assets	7,334	3,380	(2,253)	(865)	7,596
Net Property, Plant and Equipment	9,116	10,604	153	(22)	19,851
Other Assets					
Investment in subsidiaries	32	422	18,266	(18,720)	—
Equity investments in affiliates	(30)	583		(100)	453
Notes receivable, less current portion	—	62	105	(94)	73
Goodwill	1,973	12	—	—	1,985
Intangible assets, net	925	232	4	(21)	1,140
Nuclear decommissioning trust fund	551		—	—	551
Deferred income taxes	—	681	521	—	1,202
Derivative instruments	110	202	—	(1)	311
Other non-current assets	76	281	383	—	740
Total other assets	3,637	2,475	19,279	(18,936)	6,455
Total Assets	$20,087	$ 16,459	$17,179	$ (19,823)	$ 33,902
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$1	$ 1,029	$20	$ —	$ 1,050
Accounts payable	652	352	34	—	1,038
Accounts payable - affiliate	1,350	760	(1,253)	(857)	—
Derivative instruments	859	204	—	(8)	1,055
Deferred income taxes	—	—	—	—	—
Cash collateral received in support of energy risk management activities	6	57	—	—	63
Accrued expenses and other current liabilities	297	410	291	—	998
Total current liabilities	3,165	2,812	(908)	(865)	4,204
Other Liabilities					
Long-term debt and capital leases	317	7,837	7,707	(94)	15,767

Nuclear decommissioning reserve	294	—	—	—	294
Nuclear decommissioning trust liability	324	—	—	—	324
Postretirement and other benefit obligations	218	194	94	—	506
Deferred income taxes	1,024	(1,002)	—	—	22
Derivative instruments	147	49	—	(1)	195
Out-of-market contracts	127	1,050	—	—	1,177
Other non-current liabilities	194	421	80	—	695
Total non-current liabilities	2,645	8,549	7,881	(95)	18,980
Total liabilities	5,810	11,361	6,973	(960)	23,184
3.625% Preferred Stock			249		249
Stockholders' Equity	14,277	5,098	9,957	(18,863)	10,469
Total Liabilities and Stockholders' Equity	$20,087	$16,459	$17,179	$(19,823)	$33,902

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2013

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
	(In millions)				
Net Cash Provided/(Used) by Operating Activities	2,318	(217)	(2,546)	1,715	1,270
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(1,722)	7	1,715	—	—
Acquisition of business, net of cash acquired		(179)	(315)	—	(494)
Capital expenditures	(528)	(1,413)	(46)	—	(1,987)
Increase in restricted cash, net	(1)	(22)	1	—	(22)
Decrease in restricted cash - U.S. DOE projects		(31)	5	—	(26)
Increase in notes receivable	2	(7)	(6)	—	(11)
Proceeds from renewable energy grants		55	—	—	55
Purchases of emission allowances, net of proceeds	5	—	—	—	5
Investments in nuclear decommissioning trust fund securities	(514)	—	—	—	(514)
Proceeds from sales of nuclear decommissioning trust fund securities	488	—	—	—	488
Proceeds/(purchases) from sale of assets, net	13	—	—	—	13
Other	(4)	(11)	(20)	—	(35)
Net Cash Used by Investing Activities	(2,261)	(1,601)	1,334	—	(2,528)
Cash Flows from Financing Activities					
Proceeds/(payments) from intercompany loans	—	—	1,715	(1,715)	—
Payment of dividends to preferred stockholders			(154)	—	(154)
Payments of intercompany dividends	—	—	—	—	—
Payment for treasury stock	—	—	(25)	—	(25)
Payments for settlement of acquired derivatives that include financing elements	(79)	346	—	—	267
Proceeds from issuance of long-term debt	—	1,292	485	—	1,777
Sale proceeds and other contributions from noncontrolling interests in subsidiaries	—	531	—	—	531
Proceeds from issuance of common stock	—	—	16	—	16
Payment of debt issuance and hedging costs	—	(21)	(29)	—	(50)
Payments for short and long-term debt	—	(716)	(219)	—	(935)
Net Cash (Used)/Provided by Financing Activities	(79)	1,432	1,789	(1,715)	1,427
Effect of exchange rate changes on cash and cash equivalents	—	(2)	—	—	(2)
Net Increase/(decrease) in Cash and Cash Equivalents	(22)	(388)	577	—	167
	78	1,258	751	—	2,087

Cash and Cash Equivalents at Beginning of Period					
Cash and Cash Equivalents at End of Period	$56	$ 870	$ 1,328	$ —	$ 2,254

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2012

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
	(In millions)				
Operating Revenues					
Total operating revenues	$7,998	$ 509	$—	$ (85)	$ 8,422
Operating Costs and Expenses					
Cost of operations	5,916	300	—	(76)	6,140
Depreciation and amortization	860	79	11	—	950
Selling, general and administrative	466	45	307	(11)	807
Acquisition-related transactions and integration costs	—	53	54	—	107
Development activity expense	—	32	36	—	68
Total operating costs and expenses	7,242	509	408	(87)	8,072
Operating Income/(Loss)	756	—	(408)	2	350
Other (Expense)/Income					
Equity in earnings/(losses) of consolidated subsidiaries	30	(15)	620	(635)	—
Equity in earnings/(losses) of unconsolidated affiliates	8	31	(2)	—	37
Bargain purchase gain related to GenOn acquisition	—	—	296	—	296
Impairment charge on investment	(2)	—	—	—	(2)
Other income, net	6	6	9	(2)	19
Loss on debt extinguishment	—	—	(51)	—	(51)
Interest expense	(26)	(90)	(545)	—	(661)
Total other income/(expense)	16	(68)	327	(637)	(362)
Income/(Loss) Before Income Taxes	772	(68)	(81)	(635)	(12)
Income tax expense/(benefit)	237	(188)	(376)	—	(327)
Net Income	$535	$ 120	$295	$ (635)	$ 315
Less: Net income attributable to noncontrolling interest	—	20	—	—	20
Net Income attributable to NRG Energy, Inc	$535	$ 100	$295	$ (635)	$ 295

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME
For the Year Ended December 31, 2012

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income	$535	$ 120	$295	$ (635)	$315
Other comprehensive income/(loss), net of tax					
Unrealized loss on derivatives, net	(160)	(30)	(214)	241	(163)
Foreign currency translation adjustments, net	—	(2)	1	—	(1)
Reclassification adjustment for translation loss realized upon sale of Schkopau, net	—	(11)	—	—	(11)
Available-for-sale securities, net	—	—	3	—	3
Defined benefit plan, net	(38)	—	(14)	—	(52)
Other comprehensive loss	(198)	(43)	(224)	241	(224)
Comprehensive income	337	77	71	(394)	91
Less: Comprehensive income attributable to noncontrolling interest	—	20	—	—	20
Comprehensive income attributable to NRG Energy, Inc.	337	57	71	(394)	71
Dividends for preferred shares	—	—	9	—	9
Comprehensive income available for common stockholders	$337	$ 57	$62	$ (394)	$62

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2012

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
	(In millions)				
ASSETS					
Current Assets					
Cash and cash equivalents	$78	$ 1,258	$751	$ —	$ 2,087
Funds deposited by counterparties	131	140	—	—	271
Restricted cash	11	196	10	—	217
Accounts receivable - trade, net	807	254	—	—	1,061
Inventory	472	431	—	—	903
Derivative instruments	2,058	604	—	(18)	2,644
Deferred income taxes	(153)	10	199	—	56
Cash collateral paid in support of energy risk management activities	81	148	—	—	229
Renewable energy grant receivable	—	58	—	—	58
Prepayments and other current assets	2,966	(12)	(2,518)	10	446
Total current assets	6,451	3,087	(1,558)	(8)	7,972
Net Property, Plant and Equipment	9,905	10,147	121	(20)	20,153
Other Assets					
Investment in subsidiaries	244	(102)	17,565	(17,707)	—
Equity investments in affiliates	33	633	10	—	676
Notes receivable, less current portion	3	74	531	(529)	79
Goodwill	1,944	12	—	—	1,956
Intangible assets, net	1,042	187	33	(52)	1,210
Nuclear decommissioning trust fund	473	—	—	—	473
Deferred income taxes	(915)	1,886	232	—	1,203
Derivative instruments	149	515	—	(2)	662
Other non-current assets	85	304	210	—	599
Total other assets	3,058	3,509	18,581	(18,290)	6,858
Total Assets	$19,414	$ 16,743	$17,144	$ (18,318)	$ 34,983
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$1	$ 137	$15	$ (6)	$ 147
Accounts payable	541	585	46	—	1,172
Accounts payable - affiliate	(55)	1,421	(1,366)	—	—
Derivative instruments	1,726	271	2	(18)	1,981
Cash collateral received in support of energy risk management activities	131	140	—	—	271
Accrued expenses and other current liabilities	354	502	243	—	1,099
Total current liabilities	2,698	3,056	(1,060)	(24)	4,670
Other Liabilities					
Long-term debt and capital leases	310	8,459	7,496	(529)	15,736
Nuclear decommissioning reserve	354	—	—	—	354

Nuclear decommissioning trust liability	273	—	—	—	273
Postretirement and other benefit obligations	431	326	46	—	803
Deferred income taxes	—	—	55	—	55
Derivative instruments	312	190	—	(2)	500
Out-of-market commodity contracts	180	1,129	—	(31)	1,278
Other non-current liabilities	187	520	89	—	796
Total non-current liabilities	2,047	10,624	7,686	(562)	19,795
Total liabilities	4,745	13,680	6,626	(586)	24,465
3.625% Preferred Stock	—	—	249	—	249
Stockholders' Equity	14,669	3,063	10,269	(17,732)	10,269
Total Liabilities and Stockholders' Equity	$19,414	$ 16,743	$17,144	$ (18,318)	$ 34,983

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2012

	Guarantor Subsidiaries (In millions)	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
Cash Flows from Operating Activities					
Net Cash Provided/Used by Operating Activities	2,163	66	(902)	(178)	1,149
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(1,792)	792	—	1,000	—
Acquisition of businesses, net of cash acquired	—	(17)	(64)	—	(81)
Cash acquired in GenOn acquisition	—	983	—	—	983
Capital expenditures	(241)	(3,091)	(64)	—	(3,396)
Increase in restricted cash, net	(3)	(63)	—	—	(66)
Decrease in restricted cash - U.S. DOE projects	—	121	43	—	164
Increase in notes receivable	(1)	(21)	(2)	—	(24)
Purchases of emission allowances, net of proceeds	(1)	—	—	—	(1)
Investments in nuclear decommissioning trust fund securities	(436)	—	—	—	(436)
Proceeds from sales of nuclear decommissioning trust fund securities	399	—	—	—	399
Proceeds from renewable energy grants	3	59	—	—	62
Proceeds from sale of assets, net	133	—	4	—	137
Equity investment in unconsolidated affiliate	(1)	(12)	(12)	—	(25)
Other	24	—	(2)	—	22
Net Cash Used by Investing Activities	(1,916)	(1,249)	(97)	1,000	(2,262)
Cash Flows from Financing Activities					
Proceeds from intercompany loans	—	—	1,000	(1,000)	—
Payment of dividends to preferred stockholders	—	—	(50)	—	(50)
Payment of intercompany dividends	(172)	(6)	—	178	—
Net (payments of)/receipts from acquired derivatives that include financing elements	(83)	15	—	—	(68)
Proceeds from issuance of long-term debt	42	2,105	1,018	—	3,165
Cash proceeds from sale of noncontrolling interest in subsidiary	—	347	—	—	347
Payment of debt issuance and hedging costs	—	(19)	(16)	—	(35)
Payments of short and long-term debt	—	(82)	(1,178)	—	(1,260)
Net Cash (Used)/Provided by Financing Activities	(213)	2,360	774	(822)	2,099
Effect of exchange rate changes on cash and cash equivalents	—	(4)	—	—	(4)
Net Increase/(Decrease) in Cash and Cash Equivalents	34	1,173	(225)	—	982
Cash and Cash Equivalents at Beginning of Period	44	85	976	—	1,105
Cash and Cash Equivalents at End of Period	$ 78	$ 1,258	$ 751	$ —	$ 2,087

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2011

	Guarantor Subsidiaries (In millions)	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
Operating Revenues					
Total operating revenues	$8,730	$ 381	$—	$ (32)	$ 9,079
Operating Costs and Expenses					
Cost of operations	6,489	277	—	(21)	6,745
Depreciation and amortization	843	40	13	—	896
Impairment losses	160	—	—	—	160
Selling, general and administrative	334	4	252	(4)	586
Development activity expenses	—	11	46	—	57
Total operating costs and expenses	7,826	332	311	(25)	8,444
Operating Income/(Loss)	904	49	(311)	(7)	635
Other Income					
Equity in earnings/(losses) of consolidated subsidiaries	24	(7)	593	(610)	—
Equity in earnings of unconsolidated affiliates	10	25	—	—	35
Impairment charge on investment	(495)	—	—	—	(495)
Other income, net	2	13	4	—	19
Loss on debt extinguishment	—	—	(175)	—	(175)
Interest expense	(59)	(56)	(550)	—	(665)
Total other expense	(518)	(25)	(128)	(610)	(1,281)
Income/(Loss) Before Income Taxes	386	24	(439)	(617)	(646)
Income tax (benefit)/expense	(214)	7	(636)	—	(843)
Net Income attributable to NRG Energy, Inc	$600	$ 17	$197	$ (617)	$ 197

(a) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Year Ended December 31, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income	$600	$17	$197	$(617)	$197
Other comprehensive income/(loss), net of tax					
Unrealized loss on derivatives, net	(303)	(27)	(345)	366	(309)
Foreign currency translation adjustments, net	—	(2)	—	—	(2)
Available-for-sale securities, net	—	—	(1)	—	(1)
Defined benefit plan, net	(34)	—	(12)	—	(46)
Other comprehensive loss	(337)	(29)	(358)	366	(358)
Comprehensive income/(loss) attributable to NRG Energy, Inc.	263	(12)	(161)	(251)	(161)
Dividends for preferred shares	—	—	9	—	9
Comprehensive income/(loss) available for common stockholders	$263	$(12)	$(170)	$(251)	$(170)

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2011

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Elimin-ations [(a)]	Consolidated Balance
	(In millions)				
Cash Flows from Operating Activities					
Net Cash Provided by Operating Activities	621	294	1,620	(1,369)	1,166
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	796	—	287	(1,083)	—
Investment in subsidiaries	—	(1,300)	—	1,300	—
Capital expenditures	(383)	(1,882)	(45)	—	(2,310)
Acquisition of business, net of cash acquired	—	(115)	(262)	—	(377)
Increase in restricted cash	(5)	(29)	(1)	—	(35)
Increase in restricted cash to support equity requirements for U.S. DOE funded projects	—	(162)	(53)	—	(215)
Decrease in notes receivable	—	12	—	—	12
Purchases of emission allowances, net of proceeds	(19)	—	—	—	(19)
Investments in nuclear decommissioning trust fund securities	(406)	—	—	—	(406)
Proceeds from sales of nuclear decommissioning trust fund securities	385	—	—	—	385
Proceeds from sale of assets, net	13	(6)	—	—	7
Equity investment in unconsolidated affiliates, net	(2)	(64)	—	—	(66)
Other	(2)	(8)	(13)	—	(23)
Net Cash Provided/(Used) by Investing Activities	377	(3,554)	(87)	217	(3,047)
Cash Flows from Financing Activities					
(Payments of)/proceeds from intercompany loans	(1,112)	825	(796)	1,083	—
Payment of intercompany dividends	(65)	(4)	—	69	—
Payment for dividends to preferred stockholders	—	—	(9)	—	(9)
Payments for acquired derivatives including financing elements	(83)	—	—	—	(83)
Payment for treasury stock	—	—	(430)	—	(430)
Installment proceeds from sale of noncontrolling interest of subsidiary	—	29	—	—	29
Proceeds from issuance of common stock	—	—	2	—	2
Proceeds from issuance of long-term debt	138	1,290	4,796	—	6,224
Proceeds from issuance of term loan for funded letter of credit facility	—	1,300	—	—	1,300
Increase in restricted cash supporting funded letter of credit facility	—	—	(1,300)	—	(1,300)
Payment of debt issuance and hedging costs	—	(92)	(115)	—	(207)
Payments of short and long-term debt	—	(116)	(5,377)	—	(5,493)
Net Cash (Used)/Provided by Financing Activities	(1,122)	3,232	(3,229)	1,152	33
Effect of exchange rate changes on cash and cash equivalents	—	2	—	—	2
Net Decrease in Cash and Cash Equivalents	(124)	(26)	(1,696)	—	(1,846)
Cash and Cash Equivalents at Beginning of Period	168	111	2,672	—	2,951

Cash and Cash Equivalents at End of Period	$44	$ 85	$ 976	$ —	$ 1,105

(a) All significant intercompany transactions have been eliminated in consolidation.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2013, 2012, and 2011

	Balance at Beginning of Period (In millions)	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Allowance for doubtful accounts, deducted from accounts receivable					
Year Ended December 31, 2013	$32	$66	$—	$(58) [(a)]	40
Year Ended December 31, 2012	23	46	—	(37) [(a)]	32
Year Ended December 31, 2011	25	60	—	(62) [(a)]	23
Income tax valuation allowance, deducted from deferred tax assets					
Year Ended December 31, 2013	$191	$32	$68	$—	291
Year Ended December 31, 2012	83	5	103	—	191
Year Ended December 31, 2011	191	(63)	(45)	—	83

(a) Represents principally net amounts charged as uncollectible.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NRG ENERGY, INC.
(Registrant)

By: /s/ DAVID W. CRANE

David W. Crane
Chief Executive Officer

Date: February 28, 2014

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints David W. Crane, David R. Hill and Brian E. Curci, each or any of them, such person's true and lawful attorney-in-fact and agent with full power of substitution and resubstitution for such person and in such person's name, place and stead, in any and all capacities, to sign any and all amendments to this report on Form 10-K, and to file the same with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing necessary or desirable to be done in and about the premises, as fully to all intents and purposes as such person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or his or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

In accordance with the Exchange Act, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on February 28, 2014.

Signature	Title	Date
/s/ DAVID W. CRANE David W. Crane	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2014
/s/ KIRKLAND B. ANDREWS Kirkland B. Andrews	Chief Financial Officer (Principal Financial Officer)	February 28, 2014
/s/ RONALD B. STARK Ronald B. Stark	Chief Accounting Officer (Principal Accounting Officer)	February 28, 2014
/s/ HOWARD E. COSGROVE Howard E. Cosgrove	Chairman of the Board	February 28, 2014
/s/ EDWARD R. MULLER Edward R. Muller	Vice Chairman of the Board	February 28, 2014
/s/ E. SPENCER ABRAHAM E. Spencer Abraham	Director	February 28, 2014
/s/ KIRBYJON H. CALDWELL Kirbyjon H. Caldwell	Director	February 28, 2014
/s/ LAWRENCE S. COBEN Lawrence S. Coben	Director	February 28, 2014
/s/ TERRY G. DALLAS Terry G. Dallas	Director	February 28, 2014
/s/ WILLIAM E. HANTKE William E. Hantke	Director	February 28, 2014
/s/ PAUL W. HOBBY Paul W. Hobby	Director	February 28, 2014
/s/ GERALD LUTERMAN Gerald Luterman	Director	February 28, 2014
/s/ ANNE C. SCHAUMBURG Anne C. Schaumburg	Director	February 28, 2014
/s/ EVAN J. SILVERSTEIN Evan J. Silverstein	Director	February 28, 2014
/s/ THOMAS H. WEIDEMEYER Thomas H. Weidemeyer	Director	February 28, 2014
/s/ WALTER R. YOUNG Walter R. Young	Director	February 28, 2014

EXHIBIT INDEX

Number	Description	Method of Filing
2.1	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 19, 2003.
2.2	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 19, 2003.
2.3	Acquisition Agreement, dated as of September 30, 2005, by and among NRG Energy, Inc., Texas Genco LLC and the Direct and Indirect Owners of Texas Genco LLC.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 3, 2005.
2.4	Purchase and Sale Agreement by and between Denali Merger Sub and NRG Energy, Inc. dated as of August 13, 2010.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 13, 2010.
2.5	Agreement and Plan of Merger, dated as of July 20, 2012, by and among NRG Energy, Inc., Plus Energy Corporation and GenOn Energy, Inc.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on July 23, 2012.
2.6	Plan Sponsor Agreement, dated October 18, 2013, by and among NRG Energy, Inc., NRG Energy Holdings, Inc., Edison Mission Energy, certain of Edison Mission Energy’s debtor subsidiaries, the Official Committee of Unsecured Creditors of Edison Mission Energy and its debtor subsidiaries, the PoJo Parties (as defined therein) and the proponent noteholders thereto.	Incorporated herein by reference to Exhibit 2.1 to Amendment No. 1 to the Registrant’s current report on Form 8-K filed on October 21, 2013.
2.7	Asset Purchase Agreement, dated October 18, 2013, by and among NRG Energy, Inc., Edison Mission Energy and NRG Energy Holdings Inc.	Incorporated herein by reference to Exhibit 2.2 to Amendment No. 1 to the Registrant’s current report on Form 8-K filed on October 21, 2013.
3.1	Amended and Restated Certificate of Incorporation.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 3, 2012.
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 14, 2012.
3.3	Second Amended and Restated By-Laws.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 14, 2012.
3.4	Certificate of Designations of 3.625% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on August 11, 2005.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 11, 2005.
3.5	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 4, 2006.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 10, 2006.
3.6	Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q

	Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on February 27, 2008.	filed on May 1, 2008.
3.7	Second Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 8, 2008.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on October 30, 2008.
4.1	Supplemental Indenture dated as of December 30, 2005, among NRG Energy, Inc., the subsidiary guarantors named on Schedule A thereto and Law Debenture Trust Company of New York, as trustee.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on January 4, 2006.
4.2	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto dated as of January 6, 2004, together with Annex A to the Common Agreement.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 16, 2004.
4.3	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 16, 2004.
4.4	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 16, 2004.

4.5	Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 31, 2003.
4.6	Specimen of Certificate representing common stock of NRG Energy, Inc.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on August 4, 2006.
4.7	Indenture, dated February 2, 2006, among NRG Energy, Inc. and Law Debenture Trust Company of New York.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on February 6, 2006.
4.8	Form of 8.5% Senior Note due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on June 5, 2009.
4.9	Twenty-Second Supplemental Indenture, dated June 5, 2009, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on June 5, 2009.
4.10	Twenty-Third Supplemental Indenture, dated July 14, 2009, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on July 15, 2009.
4.11	Twenty-Seventh Supplemental Indenture, dated October 5, 2009, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 6, 2009.
4.12	Thirty-First Supplemental Indenture, dated as of April 16, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.50% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 21, 2010.
4.13	Thirty-Fifth Supplemental Indenture, dated as of June 23, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.50% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on June 29, 2010.
4.14	Thirty-Sixth Supplemental Indenture, dated August 20, 2010, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 20, 2010.

4.15	Form of 8.25% Senior Note due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 20, 2010.
4.16	Registration Rights Agreement, dated August 20, 2010, among NRG Energy, Inc., the guarantors named therein and Citigroup Global Markets Inc., Banc of America Securities LLC and Deutsche Bank Securities Inc., as representatives of the several initial purchasers.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 20, 2010.
4.17	Fortieth Supplemental Indenture, dated as of December 15, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.50% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 16, 2010.
4.18	Forty-First Supplemental Indenture, dated as of December 15, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 16, 2010.
4.19	Forty-Second Supplemental Indenture, dated January 26, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on January 28, 2011.
4.20	Form of 7.625% Senior Note due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on January 28, 2011.
4.21	Registration Rights Agreement, dated January 26, 2011, among NRG Energy, Inc., the guarantors named therein and J.P. Morgan Securities LLC, as initial purchaser.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on January 28, 2011.

4.22	Forty-Third Supplemental Indenture, dated April 22, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's Registration Statement on Form S-4 filed on July 11, 2011.
4.23	Forty-Seventh Supplemental Indenture, dated May 20, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.24	Forty-Eighth Supplemental Indenture, dated May 20, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.25	Forty-Ninth Supplemental Indenture, dated May 20, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.26	Fiftieth Supplemental Indenture, dated May 24, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.27	Form of 7.625% Senior Note due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.28	Fifty-First Supplemental Indenture, dated May 24, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.29	Form of 7.875% Senior Note due 2021.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.30	Registration Rights Agreement, dated May 24, 2011, among NRG Energy, Inc., the guarantors named therein and Morgan Stanley & Co. Incorporated, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., J.P. Morgan Securities LLC and RBS Securities Inc., as representatives of the initial purchasers.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 25, 2011.

4.31	Fifty-Third Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.32	Fifty-Fourth Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.33	Fifty-Fifth Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.34	Fifty-Sixth Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.35	Fifty-Seventh Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on November 8, 2011.

4.36	Fifty-Ninth Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.37	Sixtieth Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.38	Sixty-First Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.39	Sixty-Second Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.40	Sixty-Third Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.41	Sixty-Fifth Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.42	Sixty-Sixth Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.43	Sixty-Seventh Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.44	Sixty-Eighth Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.45	Sixty-Ninth Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named	Incorporated herein by reference to the Registrant's current report on Form 8-K filed

	therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	on May 11, 2012.
4.46	Seventieth Supplemental Indenture, dated September 24, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on September 24, 2012.
4.47	Form of 6.625% Senior Note due 2023.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on September 24, 2012.
4.48	Seventy-First Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.49	Seventy-Second Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.50	Seventy-Third Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 12, 2012.

4.51	Seventy-Fourth Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.’s 7.625% Senior Notes due 2019.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.52	Seventy-Fifth Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.’s 7.875% Senior Notes due 2021.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.53	Seventy-Sixth Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.’s 6.625% Senior Notes due 2023.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.54	Senior Indenture, dated December 22, 2004, between Reliant Energy, Inc. and Wilmington Trust Company.	Incorporated herein by reference to GenOn Energy, Inc.’s current report on Form 8-K filed on December 27, 2004.
4.55	Fourth Supplemental Indenture, dated June 13, 2007, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company as Trustee, re: GenOn Energy, Inc.’s 7.625% Senior Notes due 2014.	Incorporated herein by reference to GenOn Energy Inc.'s current report on Form 8-K filed on June 15, 2007.
4.56	Fifth Supplemental Indenture, dated June 13, 2007, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company as Trustee, re: GenOn Energy, Inc.’s 7.875% Senior Notes due 2017.	Incorporated herein by reference to Exhibit 4.2 to GenOn Energy Inc.'s current report on Form 8-K filed June 15, 2007.
4.57	Indenture, dated May 1, 2001, between Mirant Americas Generation, Inc. and Bankers Trust Company as Trustee.	Incorporated herein by reference to Exhibit 4.1 to Mirant Americas Generation, Inc.'s Registration Statement on Form S-4 filed on June 18, 2001.
4.58	Third Supplemental Indenture, dated May 1, 2001, between Mirant Americas Generation, Inc. and Bankers Trust Company as Trustee, re: GenOn Americas Generation, LLC’s 9.125% Senior Notes due 2031.	Incorporated herein by reference to Exhibit 4.4 to Mirant Americas Generation, Inc.'s Registration Statement on Form S-4 filed on June 18, 2001.
4.59	Fifth Supplemental Indenture, dated October 9, 2001, between Mirant Americas Generation, Inc. and Bankers Trust Company as Trustee, re: GenOn Americas Generation, LLC’s 8.5% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.6 to Mirant Americas Generation, Inc.'s Registration Statement on Form S-4/A filed on May 7, 2002.
4.60	Sixth Supplemental Indenture, dated November 1, 2001, between Mirant Americas Generation LLC and Bankers Trust Company, re: Indenture, dated May 1, 2001.	Incorporated herein by reference to Exhibit 4.6 to Mirant Corporation's annual report on Form 10-K filed on February 27, 2009.
4.61	Seventh Supplemental Indenture, dated January 3, 2006, between Mirant Americas Generation LLC and Wells Fargo Bank National Association (as successor to Bankers Trust Company), re: Indenture, dated May 1, 2001.	Incorporated herein by reference to Exhibit 4.1 to Mirant Americas Generation, LLC's quarterly report on Form 10-Q filed on May 14, 2007.

4.62	Senior Notes Indenture, dated October 4, 2010, by GenOn Escrow Corp. and Wilmington Trust Company as trustee, re: GenOn Energy, Inc.'s 9.5% Senior Notes due 2018 and 9.875% Senior Notes due 2020.	Incorporated by reference to Exhibit 4.4 to Mirant Corporation's quarterly report on Form 10-Q filed on November 5, 2010.
4.63	Supplemental Indenture, dated December 3, 2010, between GenOn Energy, Inc. and Wilmington Trust Company as trustee, re: GenOn Energy, Inc.'s 9.5% Senior Notes due 2018 and 9.875% Senior Notes due 2020.	Incorporated by reference to Exhibit 4.2 to GenOn Energy Inc.'s current report on Form 8-K filed on December 7, 2010.
4.64	Seventy-Seventh Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.65	Seventy-Eighth Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.66	Seventy-Ninth Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.67	Eightieth Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on January 9, 2013.

4.68	Eighty-First Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.69	Eighty-Second Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.70	Eighty-Third Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.71	Eighty-Fourth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.72	Eighty-Fifth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.73	Eighty-Sixth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.74	Eighty-Seventh Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.75	Eighty-Eighth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.76	Eighty-Ninth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.7 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.77	Ninetieth Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on May 3, 2013.

4.78	Ninety-First Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.79	Ninety-Second Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.8	Ninety-Third Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.81	Ninety-Fourth Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.82	Ninety-Fifth Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.83	Ninety-Sixth Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.84	Ninety-Seventh Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on September 6, 2013.

4.85	Ninety-Eighth Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.86	Ninety-Ninth Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.87	One Hundredth Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.88	One Hundred-First Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.89	One Hundred-Second Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.90	One Hundred-Third Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.91	One Hundred-Fourth Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.92	One Hundred-Fifth Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2019.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.93	One Hundred-Sixth Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.94	One Hundred-Seventh Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on October 8, 2013.

	6.626% Senior Notes due 2023.	
4.95	One Hundred-Eighth Supplemental Indenture, dated as of November 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019, 8.25% Senior Notes due 2020, 7.625% Senior Notes due 2018, 7.625% Senior Notes due 2019, 7.875% Senior Notes due 2021 and 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on November 13, 2013.
10.1	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.	Incorporated herein by reference to the Registrant's Registration Statement on Form S-1, as amended, Registration No. 333-33397.
10.2	Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.	Incorporated herein by reference to the Registrant's Registration Statement on Form S-1, as amended, Registration No. 333-33397.
10.3*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 30, 2005.
10.4*	Form of NRG Energy, Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 30, 2005.
10.5*	Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on November 9, 2004.
10.6*	Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on November 9, 2004.
10.7*	Form of NRG Energy, Inc. Long Term Incentive Plan Performance Unit Agreement.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 23, 2010.

10.8*	Amended and Restated Annual Incentive Plan for Designated Corporate Officers.	Incorporated herein by reference to the Registrant's 2009 proxy statement on Schedule 14A filed on June 16, 2009.
10.9	Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.	Incorporated herein by reference to the Registrant's annual report on Form 10-K for the quarter ended March 30, 2005.
10.10	Purchase Agreement (West Coast Power) dated as of December 27, 2005, by and among NRG Energy, Inc., NRG West Coast LLC (Buyer), DPC II Inc. (Seller) and Dynegy, Inc.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 28, 2005.
10.11	Purchase Agreement (Rocky Road Power), dated as of December 27, 2005, by and among Termo Santander Holding, L.L.C.(Buyer), Dynegy, Inc., NRG Rocky Road LLC (Seller) and NRG Energy, Inc.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 28, 2005.
10.12	Stock Purchase Agreement, dated as of August 10, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 11, 2005.
10.13	Agreement with respect to the Stock Purchase Agreement, dated December 19, 2008, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.14	Investor Rights Agreement, dated as of February 2, 2006, by and among NRG Energy, Inc. and Certain Stockholders of NRG Energy, Inc. set forth therein.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on February 8, 2006.
10.15†	Terms and Conditions of Sale, dated as of October 5, 2005, between Texas Genco II LP and Freight Car America, Inc., (including the Proposal Letter and Amendment thereto).	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on March 7, 2006.
10.16*	Amended and Restated Employment Agreement, dated December 4, 2008, between NRG Energy, Inc. and David Crane.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.17*	CEO Compensation Table.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on December 9, 2009.
10.18	Limited Liability Company Agreement of NRG Common Stock Finance I LLC.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 10, 2006.
10.19	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 10, 2006.
10.20	Amendment Agreement, dated February 27, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.21	Amendment Agreement, dated December 19, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.

	Credit Suisse Securities (USA) LLC.	
10.22	Amendment Agreement, dated December 19, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance II LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.23	Agreement with respect to Note Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.24	Agreement with respect to Note Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance II LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.25	Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 10, 2006.
10.26	Preferred Interest Amendment Agreement, dated February 27, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.27	Preferred Interest Amendment Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.28	Preferred Interest Amendment Agreement, dated December 19, 2008, by and among NRG Common Stock Finance II LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.

10.28	Agreement with respect to Preferred Interest Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.29	Agreement with respect to Preferred Interest Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance II LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.30*	Amended and Restated Long-Term Incentive Plan.	Incorporated herein by reference to the Registrant's 2009 proxy statement on Schedule 14A filed on June 16, 2009.
10.31*	NRG Energy, Inc. Executive Change-in-Control and General Severance Agreement, dated December 9, 2008.	Incorporated herein by reference to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.32†	Amended and Restated Contribution Agreement (NRG), dated March 25, 2008, by and among Texas Genco Holdings, Inc., NRG South Texas LP and NRG Nuclear Development Company LLC and Certain Subsidiaries Thereof.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.33†	Contribution Agreement (Toshiba), dated February 29, 2008, by and between Toshiba Corporation and NRG Nuclear Development Company LLC.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.34†	Multi-Unit Agreement, dated February 29, 2008, by and among Toshiba Corporation, NRG Nuclear Development Company LLC and NRG Energy, Inc.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.35†	Amended and Restated Operating Agreement of Nuclear Innovation North America LLC, dated May 1, 2008.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.37†	LLC Membership Purchase Agreement between Reliant Energy, Inc. and NRG Retail LLC, dated as of February 28, 2009.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on April 30, 2009.
10.38	Project Agreement, Settlement Agreement and Mutual Release, dated March 1, 2010, by and among by and among Nuclear Innovation North America LLC, the City of San Antonio acting by and through the City Public Service Board of San Antonio, a Texas municipal utility, NINA Texas 3 LLC and NINA Texas 4 LLC, and solely for purposes of certain sections of the Settlement Agreement, by NRG Energy, Inc and NRG South Texas LP.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on March 2, 2010.
10.39†	STP 3 & 4 Owners Agreement, dated March 1, 2010, by and among Nuclear Innovation North America LLC, the City of San Antonio, NINA Texas 3 LLC and NINA Texas 4 LLC.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on March 2, 2010.
10.40*	2009 Executive Change-in-Control and General Severance Plan.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on April 1, 2010.
10.41†	Investment and Option Agreement by and among Nuclear Innovation North America LLC, Nuclear Innovation	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q

	North America Investments Holdings LLC and TEPCO Nuclear Energy America LLC, dated as of May 10, 2010.	filed on August 2, 2010.
10.42†	Parent Company Agreement by and among NRG Energy, Inc., Nuclear Innovation North America LLC, TEPCO and TEPCO Nuclear Energy America LLC, dated as of May 10, 2010.	Incorporated herein by reference to the Registrant's quarterly report on Form 10-Q filed on August 2, 2010.
10.44(a)	Letter of Credit and Reimbursement Agreement, dated as of June 30, 2010.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on July 1, 2010.
10.44(b)	Letter of Credit and Reimbursement Agreement, dated as of June 30, 2010.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on July 1, 2010.
10.45*	The NRG Energy, Inc. Amended and Restated Long Term Incentive Plan.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on August 3, 2010.
10.46	Amended and Restated Credit Agreement, dated July 1, 2011, by and among NRG Energy, Inc., the lenders party thereto, and the joint lead bookrunners and joint lead arrangers party thereto.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on July 5, 2011.
10.47*	Form of Market Stock Unit Grant Agreement.	Incorporated herein by reference to the Registrant's current report on Form 8-K/A filed on September 12, 2011.
10.48	Registration Rights Agreement, dated September 24, 2012, among NRG Energy, Inc., the guarantors named therein and Deutsche Bank Securities Inc., Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Goldman, Sachs & Co., J.P. Morgan Securities LLC, Morgan Stanley & Co. Incorporated and RBS Securities Inc., as initial purchasers.	Incorporated herein by reference to the Registrant's current report on Form 8-K filed on September 24, 2012.

10.49*	NRG 2010 Stock Plan for GenOn Employees	Incorporated herein by reference to Exhibit 10-.49 to the Registrant's annual report on Form 10-K filed on February 27, 2013.
10.50	Revolving Credit Agreement among GenOn Energy, Inc., as Borrower, GenOn Americas, Inc., as Borrower, the several lenders from time to time parties hereto, and NRG Energy, Inc., as Administrative Agent, dated as of December 14, 2012.	Incorporated herein by reference to Exhibit 10-.49 to the Registrant's annual report on Form 10-K filed on February 27, 2013.
10.51	First Amendment Agreement, dated as of February 6, 2013, to the Amended and Restated Credit Agreement and the Second Amended and Restated Collateral Trust Agreement.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's quarterly report on Form 10-Q filed on May 7, 2013.
10.52	Second Amendment Agreement, dated as of June 4, 2013, to the Amended and Restated Credit Agreement and the Second Amended and Restated Collateral Trust Agreement.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on June 10, 2013.
10.53*	NRG Energy, Inc. Long-Term Incentive Plan Market Stock Unit Agreement	Filed herewith.
10.54*	NRG Energy, Inc. 2010 Stock Plan For GenOn Employees Market Stock Unit Agreement	Filed herewith.
12.1	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges.	Filed herewith.
12.2	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividend Requirements.	Filed herewith.
21.1	Subsidiaries of NRG Energy. Inc.	Filed herewith.
23.1	Consent of KPMG LLP.	Filed herewith.
31.1	Rule 13a-14(a)/15d-14(a) certification of David W. Crane.	Filed herewith.
31.2	Rule 13a-14(a)/15d-14(a) certification of Kirkland B. Andrews.	Filed herewith.
31.3	Rule 13a-14(a)/15d-14(a) certification of Ronald B. Stark.	Filed herewith.
32	Section 1350 Certification.	Filed herewith.
101 INS	XBRL Instance Document	Filed herewith.
101 SCH	XBRL Taxonomy Extension Schema	Filed herewith.
101 CAL	XBRL Taxonomy Extension Calculation Linkbase	Filed herewith.
101 DEF	XBRL Taxonomy Extension Definition Linkbase	Filed herewith.
101 LAB	XBRL Taxonomy Extension Label Linkbase	Filed herewith.
101 PRE	XBRL Taxonomy Extension Presentation Linkbase	Filed herewith.

* Exhibit relates to compensation arrangements.

† Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Secretary of the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.