NRG ENERGY, INC.
Form 10-K
February 27, 2015

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, 2014.

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 $9,508,294,816 based on the closing sale price of $37.20 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 January 31, 2015
Common Stock, par value $0.01 per share	337,695,251

Documents Incorporated by Reference:

Portions of the Registrant's definitive Proxy Statement relating to its 2015 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:

AB32	California GHG Allowance Program
AEP	American Electric Power
ARO	Asset Retirement Obligation
ARRA	American Recovery and Reinvestment Act of 2009
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
B2B	Business-to-business, which includes demand response, commodity sales, energy efficiency and energy management services
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
BETM	Boston Energy Trading and Marketing LLC
BTU	British Thermal Unit
Buffalo Bear	Buffalo Bear, LLC, the operating subsidiary of Tapestry Wind LLC, which owns the Buffalo Bear project
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
CCF	Carbon Capture Facility
CCPI	Clean Coal Power Initiative
CDWR	California Department of Water Resources
CenterPoint	CenterPoint Energy Houston Electric, LLC
C&I	Commercial, industrial and governmental/institutional
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CPS	Combined Pollutant Standard
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
Discrete customers	Customers measured by unit sales of one-time products or services, such as connected home thermostats, portable solar products and portable battery solutions
Distributed Solar	Solar power projects 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
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act
Dominion	Dominion Resources, Inc.
DSU	Deferred Stock Unit
Dunkirk Power	Dunkirk Power LLC
El Segundo Energy Center	NRG West Holdings LLC, the subsidiary of Natural Gas Repowering LLC, which owns the El Segundo Energy Center project
EME	Edison Mission Energy
Energy Plus Holdings	Energy Plus Holdings LLC

EPA	U.S. Environmental Protection Agency

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EPC	Engineering, Procurement and Construction
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESPP	Employee Stock Purchase Plan
ESPS	Existing Source Performance Standards
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
FRCC	Florida Reliability Coordinating Council
Fresh Start	Reporting requirements as defined by ASC-852, Reorganizations
GenConn	GenConn Energy LLC
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
GHG	Greenhouse Gases
Goal Zero	Goal Zero LLC
Green Mountain Energy	Green Mountain Energy Company
GWh	Gigawatt Hour
HAP	Hazardous Air Pollutant
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, the operating subsidiary of NRG Solar Mayfair LLC, which owns the High Desert project
IL CPS	Illinois Combined Pollutant Standard
ISO	Independent System Operator, also referred to as RTOs
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
Kansas South	NRG Solar Kansas South LLC, the operating subsidiary of NRG Solar Kansas South Holdings LLC, which owns the RE Kansas South project
kWh	Kilowatt-hour
LaGen	Louisiana Generating LLC
Laredo Ridge	Laredo Ridge Wind, LLC, the operating subsidiary of Mission Wind Laredo, LLC, which owns the Laredo Ridge project
LIBOR	London Inter-Bank Offered Rate
LTIPs	

	Collectively, the NRG Long-Term Incentive Plan and the NRG GenOn Long-Term Incentive Plan
LSEs	Load Serving Entities
Marsh Landing	NRG Marsh Landing, LLC (formerly known as GenOn Marsh Landing, LLC)

Mass	Residential and Small Business
MATS	Mercury and Air Toxics Standards
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 and Plus Merger Corporation, dated as of July 20, 2012
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MOPR	Minimum Offer Price Rule
MSU	Market Stock Unit
MVA	Megavolt Ampere
MW	Megawatt
MWh	Saleable megawatt hour net of internal/parasitic load megawatt-hour
MWt	Megawatts Thermal Equivalent
NAAQS	National Ambient Air Quality Standards
NEPGA	New England Power Generators Association
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.
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, Alta Wind, Avenal, Avra Valley, AZ DG Solar, Blythe, Borrego, CVSR, El Segundo Energy Center, GenConn, High Desert, Kansas South, Marsh Landing, PFMG DG Solar, Roadrunner, South Trent and the Thermal Business.
NRG Yield Convertible Notes	$345 million aggregate principal amount of 3.50% Convertible Senior Notes due 2019 issued by NRG Yield, Inc.
NRG Yield, Inc.	NRG Yield, Inc., the owner of 44.7% 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

Nuclear Decommissioning Trust Fund	NRG's nuclear decommissioning trust fund assets, which are for the Company's portion of the decommissioning of the STP, units 1 & 2
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
Pinnacle	Pinnacle Wind, LLC, the operating subsidiary of Tapestry Wind LLC, which owns the Pinnacle project
PJM	PJM Interconnection, LLC
PM	Particulate Matter
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PU	Performance Unit
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 2005
Pure Energies	Pure Energies Group Inc.
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility under PURPA
RCRA	Resource Conservation and Recovery Act of 1976
RDS	Roof Diagnostics Solar
Recurring customers	Customers that subscribe to one or more recurring services, such as electricity, natural gas and protection products, the majority of which are retail electricity customers in Texas and the Northeast
Reliant Energy	Reliant Energy Retail Services, LLC
Repowering	Technologies utilized to replace, rebuild, or redevelop major portions of an existing electrical generating facility to achieve a substantial emissions reduction, increase facility capacity and improve system efficiency
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
Right of First Offer Agreement	Right of First Offer Agreement by and between NRG Energy, Inc. and NRG Yield, Inc.
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standards
RSS	Reliability Support Service
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
Schkopau	Kraftwerk Schkopau Betriebsgesellschaft mbH
SCR	Selective Catalytic Reduction Control System
SEC	U.S. Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
SEG	Saale Energie GmbH
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 $6.4 billion outstanding unsecured senior notes consisting of $1.1 billion of 7.625% senior notes due 2018, $1.1 billion of 8.25% senior notes due

2020, $1.1 billion of 7.875% senior notes due 2021, $1.1 billion of 6.25% senior notes due 2022, $990 million of 6.625% senior notes due 2023 and $1.0 billion of 6.25% senior notes due 2024

SERC	Southeastern Electric Reliability Council
SO_2	Sulfur Dioxide
STP	South Texas Project — nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest
STPNOC	South Texas Project Nuclear Operating Company
Taloga	Taloga Wind, LLC, the operating subsidiary of Tapestry Wind LLC, which owns the Taloga project
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
Thermal Business	NRG Yield's thermal business, which consists of thermal infrastructure assets that provide steam, hot water and/or chilled water, and in some instances electricity, to commercial businesses, universities, hospitals and governmental units
TSR	Total Shareholder Return
TWh	Terawatt Hour
U.S.	United States of America
U.S. DOE	U.S. Department of Energy
U.S. GAAP	Accounting principles generally accepted in the U.S.
Utility Scale Solar	Solar power projects, typically 20 MW or greater in size (on an alternating current basis), that are interconnected into the transmission or distribution grid to sell power at a wholesale level
VaR	Value at Risk
VIE	Variable Interest Entity
Walnut Creek	NRG Walnut Creek, LLC, the operating subsidiary of WCEP Holdings, LLC, which owns the Walnut Creek project
WCP	WCP (Generation) Holdings, Inc.
WECC	Western Electricity Coordinating Council
Yield Operating	NRG Yield Operating LLC

PART I

Item 1 — Business

General

NRG Energy, Inc., or NRG or the Company, is a competitive power company that produces, sells and delivers energy and energy products and services in major competitive power markets in the U.S. while positioning itself as a leader in the way residential, industrial and commercial consumers think about and use energy products and services. NRG is responding to a consumer-driven change to the U.S. energy industry by offering cleaner, smarter and ultimately more portable energy while enabling personal energy choice, building on the strength of one of the nation's largest and most diverse competitive power generation portfolios. The Company owns and operates approximately 52,000 MWs of generation; engages in the trading of wholesale energy, capacity and related products around those generation assets; transacts in and trades fuel and transportation services; and directly sells energy, services, and innovative, sustainable products and services to retail customers under the name "NRG" and various other retail brand names owned by NRG. NRG was incorporated as a Delaware corporation on May 29, 1992.

NRG's Business Strategy

NRG's strategy, summarized in "Enhance Generation, Expand Retail and Go Green while engaging in Smart Capital Allocation" is 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, low carbon and portable energy solutions individualized for the benefit of the end use energy consumer. This strategy is intended to enable the Company to achieve substantial sustainable growth at reasonable margins while de-risking the Company in terms of reduced and mitigated exposure both to "environmental risk" and cyclical commodity price risk. At the same time, the Company's relentless commitment to safety for its employees, customers and partners continues unabated.

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, increasingly wireless and thus portable, 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 and static 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, the Company expects energy consumers to secure increased personal control over their energy choices in the future. Nevertheless, as the Company shifts to respond to these trends that are playing out over time, the Company's immediate imperative every day remains to serve its customers and the markets in which it operates with safe, affordable, reliable and increasingly sustainable power.

To address these trends and effectuate the Company's strategy, NRG is focused on: (i) excellence in operating performance of its existing assets including repowering its power generation assets at premium sites and optimal hedging of generation assets and retail load operations; (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) investing in, and deploying, alternative energy technologies both in its wholesale portfolio through its wind and solar portfolio and, particularly, in and around its retail businesses and its customers as it transforms this part of its business into a technology-driven provider of retail energy services; and (iv) 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; including pursuing selective acquisitions, joint ventures, divestitures and investments.

To further enhance the Company's strategy, the Company has reorganized its businesses and personnel on the basis of their key target customer segments. The new businesses include NRG Business, NRG Home and NRG Renew. In addition, NRG Carbon 360 and NRG eVgo are two distinct businesses that have dedicated management and are organized separately within NRG because of their distinct capital structure, success metrics and competitive environment but are supportive of and closely coordinated with NRG's core businesses. These five companies, plus NRG Yield, are described in detail below.

NRG Business

NRG Business consists of the Company’s wholesale operations including plant operations, commercial operations, EPC, energy services and other critical related functions. NRG has traditionally referred to this business as its wholesale power generation business. In addition to the traditional functions from NRG’s wholesale power generation business, NRG Business also includes NRG’s B2B solutions, which include demand response, commodity sales, energy efficiency and energy management services, and NRG’s conventional distributed generation business, consisting of reliability, combined heat and power, thermal and district heating and cooling and large-scale distributed generation.

NRG Business is capital-intensive and commodity-driven with numerous industry participants that compete on the basis of the location of their plants, fuel mix, plant efficiency and the reliability of the services offered. NRG Business includes one of the largest and most diversified power generation portfolios in the U.S., with approximately 47,636 MW of fossil fuel and nuclear generation capacity at 93 plants as of December 31, 2014. 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.

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 Business competes with depending on the market. Competitors include regulated utilities, municipalities, cooperatives and other independent power producers, and power marketers or trading companies, including those owned by financial institutions. Many of NRG Business' generation assets, however, 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 Business now has generation assets located in or near Houston, New York City, Chicago, Washington D.C., New Jersey, southwestern Connecticut, Pittsburgh, Cleveland, and the Los Angeles, San Diego, and San Francisco metropolitan areas. These facilities, many of which are aging, 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. NRG Business believes that its extensive generation portfolio provides many asset optimization opportunities. To that end, NRG Business currently has approximately 5,626 MWs targeted for Repowering and conversion initiatives, with 905 MWs already under development or construction.

In addition, NRG Business continuously evaluates opportunities for development of new generation, on both a merchant and contracted basis. As such, the majority of NRG Business' current developments are in response to Requests For Proposals, or RFPs, for new 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 reliability mandates measured by the reserve margin, which is the market's available electric power capacity over and above the electric power capacity needed to meet peak demand levels. NRG Business competes against other power plant developers. 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. NRG Renew, which is described below, competes in a similar manner on renewable projects.

NRG Business’s B2B solutions focus on providing distributed products and services (energy solutions) as businesses seek greater reliability, cleaner power or other benefits that they cannot obtain from the grid. These solutions include system power, distributed generation, solar and wind products, carbon management and specialty services, backup generation, storage and distributed solar, demand response and energy efficiency. In providing on-site energy solutions, NRG Business often benefits from its ability to supply energy products from its wholesale generation portfolio to commercial and industrial retail customers.

NRG Business also provides energy services including operations, maintenance, technical, development and asset management services to its own facilities and to external customers. Such energy services provide NRG Business with the competitive advantage to capture the crossover value between wholesale markets and distributed resources.

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NRG Home

NRG Home is a consumer facing business that includes the Company’s mass market retail business, the Company's residential solar business and a smaller home warranty and service business, combined into NRG Home in order to offer a diverse suite of personal energy solutions for use in and outside the home. NRG Home is focused on establishing deeply integrated multi-product, multi-service customer relationships that strengthen the consumer energy experience and allow individuals to generate and manage greater amounts of their own energy and to access their power at fixed sites and on the go.

NRG Home Retail — Under NRG Home, the NRG Home Retail business provides home energy and related services as well as personal power to consumers through various brands and channels across the U.S. In 2014, NRG Home Retail delivered approximately 41 TWhs and had approximately 2.8 million Recurring customers, including 540,000 customers from the acquisition of Dominion Resources, Inc. (as described in Item 15 — Note 3, Business Acquisitions and Dispositions) plus approximately 299,000 Discrete customers of products and services. NRG Home Retail's business results make it the largest energy retailer in Texas and one of the largest retail energy providers in the U.S., with the majority of its sales in the competitive retail energy markets of Connecticut, Delaware, Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Ohio and Texas, as well as the District of Columbia.

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, call centers, websites, brokers and brick-and-mortar stores. Through its broad range of service offerings and value propositions, the NRG Home Retail business is able to attract, retain, and increase the value of its customer relationships. NRG Home's retailers are recognized for exemplary customer service, innovative smart energy and technology product offerings and environmentally friendly solutions. In 2014, NRG Home acquired Goal Zero, a leading provider of portable solar power and battery pack products and accessories, through which NRG Home Retail strengthened its cross-selling opportunities between mass market system power, residential solar and personal power via partnerships, sales channels and customer bases.

In an industry that is subject to commodity price volatility, NRG expects that an expanded core generation fleet will enable NRG Home to replicate in multiple markets, principally in the Northeast, the successful integrated wholesale-retail business model that NRG Home currently operates in the Gulf Coast region.

NRG Home Solar — NRG Home Solar offers a full complement of customer acquisition, installation and contract management services for residential solar customers. Through this full service approach, NRG Home Solar allows customers to switch to solar energy in a simple and cost-efficient manner. In 2014, the Company acquired one of the nation's leading residential solar companies, Roof Diagnostics Solar, now doing business as NRG Home Solar, to support and expand the Company's efforts to empower its customers to control their own energy choices through clean self-generation. Also in 2014, the Company acquired Pure Energies, a residential solar industry company focused on web and telephonic based customer acquisition. Pure Energies enables a simplified customer adoption process and provides NRG Home Solar national sales capabilities. In addition to leveraging the NRG Home Retail business, the combination of RDS and Pure Energies provides NRG Home Solar the platform to meet the growing demand for high quality residential solar services delivered by a market leader in delivering retail electricity services in the home.

NRG Home Solar competes against traditional power generation and retail services, including products and services provided by NRG Business and NRG Home Retail in that it offers, a full or partial alternative, to the provision of energy in and on the home. NRG Home Solar also competes with other solar companies in the downstream value chain of solar energy, including companies that subcontract the installation of these solar energy systems as well as installation, construction and roofing businesses that may offer competitive pricing. NRG Home Solar believes that its long-term track record, network of retail customers, customer acquisition capabilities and strong installation and servicing platforms make it the most competitively advantaged residential solar company in the U.S. Additionally, NRG Home Solar’s potential together with NRG Home Retail to offer customers seamless home solar/grid backup solutions, plus other cross-selling opportunities with other NRG Home products, will provide NRG Home a significant competitive advantage over time.

NRG Renew

NRG Renew focuses on the Company's existing renewables business and developing renewable products and services that are customizable generally for larger end use energy consumers, such as micro grid solutions. NRG Renew is one of the largest solar power developers and owner-operators in the U.S., having demonstrated the ability to develop, construct and finance a full range of solar energy solutions for utilities, schools, municipalities and commercial market segments. In 2014, NRG Renew became one of the largest domestic wind-operators when the Company acquired the wind assets from EME. As the traditional grid is becoming more unreliable for service-oriented merchants, and carbon pricing becomes an ever growing consideration, NRG Renew believes that its capabilities will allow it to become the sustainability and clean energy partner of choice for businesses ranging in size from local proprietors to Fortune 500 multinational corporations. It is a business that is positioned to capture emerging opportunities as the movement to sustainable energy resources continues to drive growth in this segment of the energy industry. NRG Renew, formerly known as NRG Solar, initially developed its utility scale operating portfolio by capitalizing on the first-mover advantage in response to state mandated renewable portfolio standards. As the increased demand for sustainable energy shifts to commercial and industrial market segments, health and educational institutions, governmental agencies and municipalities, NRG Renew will respond with customized, renewable led solutions supported by the breadth and depth of the Company's power generation and financing capabilities.

NRG Renew targets strategic partnerships with local, regional, national and multi-national companies and institutions to provide onsite and offsite renewable generation for their partners, highlighted by a partnership to provide 100% clean energy for all energy use at Unilever United States, Inc. and a partnership with Starwood Hotels & Resorts for the installation of solar array at multiple Starwood properties to aid Starwood in achieving its target of 30% energy reduction by 2020. As of December 31, 2014, NRG Renew had approximately 47 MWs of Distributed Solar projects, all of which are supported by long-term PPAs, in operation or under construction, including five National Football League venues as well as other commercial or institutional sites, including a 6 MW project located on the MGM Mandalay Bay complex in Las Vegas, Nevada.

Similar to NRG Business, NRG Renew also competes for new generation opportunities through RFPs. The number and type of competitors vary based on location, generation type, project size and counterparty. NRG Renew competes with traditional utilities as well as companies that provide products and services in the downstream solar and wind energy value chains. NRG Renew also competes with products and services provided by NRG Business as well as traditional utility and power plant companies.

NRG Yield

NRG Yield, Inc. is a publicly traded dividend growth-oriented company formed to serve as the primary vehicle through which NRG, supported by NRG Renew and NRG Business, owns, operates and acquires diversified contracted renewable and conventional generation and thermal infrastructure assets. As of December 31, 2014, NRG owns 55.3% of the outstanding common stock of NRG Yield, Inc. NRG Yield, Inc.'s contracted generation portfolio collectively represents 2,861 net MW as of December 31, 2014. Each of the assets sells substantially all of its output pursuant to long-term, fixed price offtake agreements with creditworthy counterparties. NRG Yield, Inc. also owns thermal infrastructure assets with an aggregate steam and chilled water capacity of 1,346 net MWt and electric generation capacity of 123 net MW. These thermal infrastructure assets provide steam, hot water and/or chilled water, and in some instances electricity, to commercial businesses, universities, hospitals and governmental units in multiple locations, principally through long-term contracts or pursuant to rates regulated by state utility commissions.

NRG Yield, Inc. provides the Company with a more competitive cost of capital consistent with the lower risk profile of long-term contracted or regulated assets. As such, 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, 2014, NRG Yield, Inc.'s stock price had increased 114.3% from its initial public offering price of $22 per share on July 17, 2013.

On February 24, 2015, NRG Yield, Inc.'s board of directors approved amendments to the NRG Yield, Inc. certificate of incorporation that would, among other things, create two new classes of capital stock, Class C common stock and

Class D common stock. The amendments will be voted on at the NRG Yield, Inc. Annual Meeting of Stockholders to be held on May 5, 2015. If such amendments are approved, NRG Yield, Inc. intends to request that the board of directors consider a distribution of shares of the Class C common stock as a dividend to the holders of the Class A common stock and a distribution of shares of the Class D common stock as a dividend to NRG, the holder of the Class B common stock. The Class C common stock and Class D common stock will have the same rights and privileges and rank equally, share ratably and be identical in all respects to the shares of Class A common stock and Class B common stock, respectively, as to all matters, except that each share of Class C common stock and Class D common stock will be entitled to 1/100th of a vote on all stockholder matters.

In addition, subject to the approval of the proposed amendments described above, NRG has agreed to amend the Right of First Offer Agreement to make additional assets available to NRG Yield, Inc. should NRG choose to sell them, including (i) two natural gas facilities totaling 895 MW of net capacity that are expected to reach COD in 2017 and 2020, (ii) an equity interest in a wind portfolio that includes wind facilities totaling approximately 934 MW of net capacity, and (iii) up to $250 million of equity interests in one or more residential or distributed solar generation portfolios developed by affiliates of NRG.

NRG Carbon 360

NRG Carbon 360 consists of the Company’s carbon capture business that plans to develop carbon capture facilities for NRG that may prolong the life of NRG’s coal fleet and convert NRG's carbon emissions from a liability to a productive asset. To that end, in July 2014, the Company formed a joint venture with JX Nippon Oil & Gas Exploration Corporation (JX Nippon), to build and operate the Petra Nova Carbon Capture Project, or the Petra Nova Project. The Petra Nova Project is expected to be a commercial-scale carbon capture system that captures 90% of the CO_2 in the processed flue gas from an existing unit at the WA Parish power plant in Fort Bend County, southwest of Houston. Commercial operation is expected in late 2016. The Petra Nova Project is being financed by: (i) up to $167 million from a U.S. DOE CCPI grant, (ii) $250 million in loans provided by the Japan Bank for International Cooperation and Mizuho Bank, Ltd., and (iii) approximately $300 million in equity contributions from each of the Company and JX Nippon. The joint venture also owns a 50% equity interest in Texas Coastal Ventures, LLC, which holds working interests in the West Ranch oil field in Jackson County, Texas. NRG Carbon 360 continues to assess oilfield opportunities both along the Gulf Coast and nationally as it looks to further monetize the carbon output of NRG's fleet. In connection with the formation of the joint venture with JX Nippon, the Company no longer has a controlling interest in the project and the joint venture is not consolidated in the Company’s financial statements. NRG Carbon 360 is reflected in the Company's NRG Business segment.

NRG eVgo

NRG eVgo, the results of which are reflected in the Company's Corporate segment, is the Company’s electric vehicle charging services business which serves the interest of NRG not only by stimulating electricity demand but also by creating a distinct, and fast growing, set of end use energy consumers secured through a nontraditional sales channel. NRG eVgo continues to build out and operate electric vehicle, or EV, charging infrastructure in the U.S. NRG eVgo provides comprehensive EV charging - at public, home, multi-family and workplace locations - in major metropolitan areas throughout the country. As of December 31, 2014, NRG eVgo had 238 operational public fast chargers. NRG eVgo offers consumers a choice of subscription-based plans, all at competitive monthly fees, as well as walk-up charging. In the third quarter of 2014, NRG eVgo initiated support of Nissan’s expanded "No Charge to Charge" program, which provides Nissan customers with up to two years of no-cost public charging on participating networks with the purchase or lease of a new Nissan LEAF, utilizing the EZ-Charge (SM) interoperability card. NRG eVgo also signed an agreement with BMW to offer i3 owners in California a one-year embedded subscription through 2015. These two agreements and NRG eVgo trial programs at more than 200 participating auto dealers have resulted in significant increases in customer count.

In addition, as part of a legal settlement, NRG eVgo has an agreement with the California Public Utilities Commission to build at least 200 public fast charging Freedom Station sites and associated work to prepare 10,000 commercial and multi-family parking spaces for electric vehicle charging in California by the end of 2016.

NRG Operations

The NRG businesses described above are all supported through the NRG operational infrastructure, which begins with the Company's asset fleet and the associated commercial and retail operations. The images below illustrate NRG's U.S. power generation and net capacity capabilities as of December 31, 2014, as well as customer, load and regional information surrounding the operation of NRG's retail businesses:

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The following table summarizes NRG's global generation portfolio as of December 31, 2014:

Global Generation Portfolio[a]
(In MW)

	NRG Business								
Generation Type	Gulf Coast	East	West	NRG Home Solar	NRG Renew	NRG Yield [b]	Total Domestic	Other (Inter-national)	Total Global
Natural gas	8,547	7,744	7,617	—	—	1,393	25,301	144	25,445
Coal	5,689	11,045	—	—	—	—	16,734	605	17,339
Oil	—	5,818	—	—	—	190	6,008	—	6,008
Nuclear	1,176	—	—	—	—	—	1,176	—	1,176
Wind	—	—	—	—	1,964	1,048	3,012	—	3,012
Utility Scale Solar	—	—	—	—	807	343	1,150	—	1,150
Distributed Solar	—	—	—	50	37	10	97	—	97
Total generation capacity	15,412	24,607	7,617	50	2,808	2,984	53,478	749	54,227
Capacity attributable to noncontrolling interest	—	—	—	—	(630)	(1,334)	(1,964)	—	(1,964)
Total net generation capacity	15,412	24,607	7,617	50	2,178	1,650	51,514	749	52,263

(a) Includes 95 active fossil fuel and nuclear plants, 14 Utility Scale Solar facilities, 35 wind farms and multiple Distributed Solar facilities. 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.

(b) 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, which are part of the NRG Yield operating segment, provide steam and chilled water capacity of approximately 1,464 MWt through the district energy business, 118 MWt of which is available under right-to-use provisions contained in agreements between two of NRG's thermal facilities and certain of their customers.

NRG's portfolio diversification and commercial operations hedging strategy provides the Company with reliable future cash flows. NRG has hedged a portion of its coal and nuclear capacity with decreasing hedge levels through 2019. 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 Gulf Coast region expiring at various dates through 2025, which largely hedges the Company's generation in this region. In addition, as of December 31, 2014, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 50% of its expected coal requirement from 2015 to 2019, excluding inventory. The Company enters into additional hedges when it deems market conditions to be favorable.

The Company also has the advantage of being able to supply its retail businesses 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 from 10 years to as much as 25 years.

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.

NRG also trades electric power, natural gas, oil, weather and related commodity and financial products, including forwards, futures, options and swaps, primarily through its ownership of Boston Energy Trading and Marketing, or BETM, which was acquired in the acquisition of EME. BETM seeks to generate profits from volatility in the price of electricity, capacity, fuels and transmission congestion by buying and selling contracts in wholesale markets under guidelines approved by the Company's risk management committee.

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, 2014, and through 2018 for the Company's Gulf Coast region:

Gulf Coast	2015	2016	2017	2018	Annual Average for 2015-2018
	(Dollars in millions unless otherwise stated)				
Net Coal and Nuclear Capacity (MW) [(a)]	6,290	6,290	6,290	6,290	6,290
Forecasted Coal and Nuclear Capacity (MW) [(b)]	4,739	5,097	5,261	5,225	5,081
Total Coal and Nuclear Sales (MW) [(c)]	5,629	2,909	1,251	1,000	2,697
Percentage Coal and Nuclear Capacity Sold Forward [(d)]	119 %	57 %	24 %	19 %	55 %
Total Forward Hedged Revenues [(e)]	$2,224	$1,128	$502	$435	
Weighted Average Hedged Price ($ per MWh) [(e)]	$45.11	$44.15	$45.82	$49.67	
Average Equivalent Natural Gas Price ($ per MMBtu) [(e)]	$3.99	$4.28	$4.42	$4.75	
Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$(12)	$118	$188	$197	
Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$40	$(109)	$(183)	$(187)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$12	$104	$144	$155	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	$8	$(86)	$(128)	$(138)	

(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, 2014, 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, 2014, and then combined with power sales to arrive at equivalent MWh hedged which is then divided by number of hours in a 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.

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, 2014, and through 2018 for the East region:

East	2015	2016	2017	2018	Annual Average for 2015-2018
	(Dollars in millions unless otherwise stated)				
Net Coal Capacity (MW) [(a)]	10,401	8,732	7,280	7,132	8,386
Forecasted Coal Capacity (MW) [(b)]	4,888	3,482	2,971	2,631	3,493
Total Coal Sales (MW) [(c)]	5,503	1,575	514	—	1,898
Percentage Coal Capacity Sold Forward [(d)]	113 %	45 %	17 %	— %	44 %
Total Forward Hedged Revenues [(e)]	$2,292	$735	$198	$—	
Weighted Average Hedged Price ($ per MWh) [(e)]	$47.56	$53.12	$43.89	$—	
Average Equivalent Natural Gas Price ($ per MMBtu) [(e)]	$3.48	$4.23	$4.33	$—	
Gas Price Sensitivity Up $0.50/MMBtu on Coal Units	$82	$160	$186	$178	
Gas Price Sensitivity Down $0.50/MMBtu on Coal Units	$14	$(97)	$(136)	$(137)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal Units	$36	$101	$145	$133	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal Units	$7	$(65)	$(103)	$(98)	

(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, 2014, 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, 2014, and then combined with power sales to arrive at equivalent MWh hedged which is then divided by number of hours in a 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 2014, NRG's retail businesses within NRG Home and NRG 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 2014, NRG's retail businesses sold approximately 63 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 from a combination of NRG's wholesale portfolio and other third parties. 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's 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:

- NRG Business — The Company's largest sources of capacity revenues are capacity auctions in PJM, ISO-NE, and NYISO. In California, there is a regulatory mandated resource adequacy requirement that is satisfied through bilateral contracts. The Company's newer generation in California is contracted under long-term tolling agreements. Certain other sites in California have short-term tolling agreements or resource adequacy contracts. In addition, 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. The remaining counterparty, with a 550 MW load service contract, accounting for 25% of the cooperative total, elected not to extend its contract when it expired 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. The Gulf Coast assets situated in the MISO market may participate in this auction. In certain circumstances, capacity from the Gulf Coast region may be sold into the PJM market. In Texas, capacity and contracted revenues are through bilateral contracts with load serving entities.
- NRG Renew — Output from renewable energy assets are 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. 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 2015. NRG actively manages its coal requirements based on forecasted generation, market volatility and its inventory on site. As of December 31, 2014, NRG had purchased forward contracts to provide fuel for approximately 50% of the Company's expected requirements from 2015 through 2019, excluding inventory. NRG purchased approximately 46 million tons of coal in 2014, of which 80% was Powder River Basin coal and lignite, and 20% 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 2015 through 2019 that have been purchased forward as of December 31, 2014:

	Percentage of Company's Requirement [(a)(b)]	
2015	100	%
2016	75	%
2017	34	%
2018	19	%
2019	21	%

(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 concentrates with only approximately 25% of STP's requirements outstanding for the duration of the operating license. Similarly, NRG is party to long-term contracts to procure STP's requirements for conversion and 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.

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, 2014, and 2013:

	Year Ended December 31, 2014				
			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)				
NRG Business					
Gulf Coast	15,412	59,872	86.6 %	9,694	44.6 %
East	24,607	51,292	81.8	10,392	25.6
West	7,617	5,409	91.1	8,967	9.0
NRG Renew	2,808	6,992			
NRG Yield [(a)]	2,984	5,011	95.1	8,702	13.5

	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)				
NRG Business					
Gulf Coast	16,599	57,193	82.9 %	9,900	41.3 %
East	20,061	34,081	80.8	10,100	17.6
West	6,229	2,876	89.5	11,800	4.8
NRG Renew	1,180	2,074			
NRG Yield [(a)]	2,037	3,443	91.4	8,900	8.5

(a) NRG Yield excludes thermal generation.

The generation performance by region for the three years ended December 31, 2014, 2013, and 2012, is shown below:

	Net Generation		
	2014	2013	2012 [(a)]
	(In thousands of MWh)		
NRG Business			
Gulf Coast			
Coal	36,794	37,635	31,144
Gas	13,968	11,674	11,229
Nuclear [(b)]	9,110	7,884	7,269
Total Gulf Coast	59,872	57,193	49,642
East			
Coal	43,604	25,853	3,228
Oil	767	364	233
Gas	6,921	7,864	1,744
Total East	51,292	34,081	5,205
West			
Gas	5,409	2,876	2,011
Total West	5,409	2,876	2,011
NRG Renew			

Solar	1,901	1,153	569
Wind	5,091	921	806
Total NRG Renew	6,992	2,074	1,375
NRG Yield			
Solar	550	520	105
Wind	1,002	334	317
Gas and Dual-Fuel	3,459	2,589	1,098
Total NRG Yield [c]	5,011	3,443	1,520

(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.

Segment Review

Effective in December 2014, 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 segregated as follows: NRG Business; NRG Home, which includes NRG Home Retail and NRG Home Solar; NRG Renew, which includes solar and wind assets, excluding those in the NRG Yield; NRG Yield and corporate activities. NRG Yield includes certain of the Company's contracted generation assets. On June 30, 2014, NRG Yield, Inc. acquired three projects from the Company: El Segundo Energy Center, formerly in the NRG Business segment, Kansas South and High Desert, both formerly in the NRG Renew segment. As the transaction was accounted for as a transfer of entities under common control, all historical periods have been recast to reflect this change.

Revenues

The following table contains a summary of NRG's operating revenues by segment for the years ended December 31, 2014, 2013, and 2012, 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, 2014						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[a]	Total Operating Revenues[b]
	(In millions)						
NRG Business	$6,480	$1,860	$1,868	$535	$ 11	$ 340	$ 11,094
NRG Home Retail	—	—	5,505	—	1	—	5,506
NRG Home Solar	—	—	12	—	—	—	12
NRG Renew	477	2	—	6	(7)	35	513
NRG Yield	173	247	—	—	(18)	181	583
Corporate and Eliminations [b]	(1,708)	(22)	(9)	(40)	—	(61)	(1,840)
Total	$5,422	$2,087	$7,376	$501	$ (13)	$ 495	$ 15,868

(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 NRG Business and NRG Home.

	Year Ended December 31, 2013						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[c]	Total Operating Revenues[d]
	(In millions)						
NRG Business	$5,335	$1,720	$1,909	$(541)	$ 21	$ 193	$ 8,637
NRG Home Retail	—	—	4,392	—	(51)	—	4,341
NRG Home Solar	—	—	4	—	—	—	4
NRG Renew	198	—	—	(1)	—	25	222
NRG Yield	103	140	—	—	(1)	137	379
Corporate and Eliminations [d]	(2,106)	(60)	(5)	(36)	—	(81)	(2,288)
Total	$3,530	$1,800	$6,300	$(578)	$ (31)	$ 274	$ 11,295

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

(d) Energy revenues include inter-segment sales primarily between NRG Business and NRG Home.

	Year Ended December 31, 2012						
	Energy	Capacity	Retail	Mark-to-		Other	Total

	Revenues	Revenues	Revenues(f)	Market Activities	Contract Amor-tization	Revenues(e)	Operating Revenues (f)
	(In millions)						
NRG Business	$3,588	$765	$ 1,907	$(413)	$ 20	$ 109	$5,976
NRG Home Retail	—	—	3,993	(5)	(116)	—	3,872
NRG Home Solar	—	—	—	—	—	3	3
NRG Renew	117	—	—	—	—	5	122
NRG Yield	33	—	—	—	(1)	143	175
Corporate and Eliminations(g)	(1,624)	(3)	—	(32)	—	(67)	(1,726)
Total	$2,114	$762	$ 5,900	$(450)	$ (97)	$ 193	$8,422

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

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

(g) Energy revenues include inter-segment sales primarily between NRG Business and NRG Home.

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 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 ISO regions 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.

Gulf Coast

NRG's Gulf Coast wholesale power generation business is principally located in the ERCOT and MISO markets. The ERCOT market is one of the nation's largest and historically fastest growing power markets. For 2014, hourly demand ranged from a low of approximately 24,540 MW to a high of approximately 66,400 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 U.S. 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 region and is served by competitive retail suppliers, except certain areas that are served by municipal utilities and electric cooperatives that have not opted into competitive choice.

Recently, 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 $7,000 per MWh but will increase 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), higher energy pricing for ISO unit commitments for capacity, and energy price adders to offset the price suppressing impacts of out-of-market commitments for reliability.

At the direction of the PUCT, ERCOT implemented an operating reserve demand curve, known as ORDC, on June 1, 2014. ORDC simulates real-time co-optimization of energy and reserves and uses price adders during scarcity conditions to reflect price formation outcomes expected under real-time co-optimization. Under ORDC, real time energy prices could rise to $9,000 per MWh during extreme scarcity events (due to value of lost load assumptions in the price curve), despite the current system wide offer cap of $7,000 per MWh.

On December 19, 2013, Entergy joined MISO and, as a result, NRG's Gulf Coast region generation assets operating in the Entergy region, are now principally located within the MISO, participating in the MISO day-ahead and real-time energy and ancillary services markets. Additionally, MISO employs a one-year forward resource adequacy 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 in the MISO region.

East

NRG's generation assets located in the East region of the U.S. 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. In 2014, ISO-NE began transitioning its capacity market structure into a hybrid energy-capacity market, whereby suppliers would be subject to extremely high capacity penalties if they failed to deliver during reserve shortage conditions. As part of the reforms, capacity suppliers are allowed to include a wider array of costs in their capacity market bids, including a risk premium to account for the enhanced penalty risk. The “Performance Incentives” program, as it is known, takes effect in the 2018/2019 delivery year.

In December 2014, PJM proposed a similar set of rules, modeled on the New England rules. Like New England’s Performance Incentive program, PJM’s “Capacity Performance” proposal also imposes stiff new penalties on suppliers that fail to deliver energy during defined emergency conditions. FERC is expected to rule on PJM’s Capacity Performance proposal in early 2015.

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 LSEs. The CPUC also determines specific capacity requirements for specified local areas utilizing inputs from the CAISO. Both the 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 is pursuing repowering projects at several of its Southern California sites pursuant to long-term contracts.

Renew

The Company operates a fast-growing fleet of utility scale and distributed renewable generating assets across the U.S. Many states have 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 renewable generating facilities. The Company currently has PPAs for over 500 MW of solar generation assets located in California and Arizona and over 1,500 MW of wind generation assets. 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. On December 19, 2014, the Tax Increase Prevention Act of 2014, or the TIPA, was enacted, which extended the PTC through the end of 2014. The effective date of the TIPA is January 1, 2014, and as such, certain projects that commenced construction or took other qualifying actions during 2014 are now eligible to claim the PTC. This extension may create additional competition for NRG Renew and NRG Business with the development of additional generation assets, but also may create additional acquisition opportunities for NRG Yield to the extent such generation assets are contracted.

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Home

NRG Home, which includes the NRG Home Retail business and the NRG Home Solar business, provides customers with a full suite of competitive energy supply options, which include everything from traditional retail supply arrangements, rooftop solar, home energy products and services, portable power and battery products.

NRG Home's retail business sells energy and related services as well as portable power and battery solutions to customers across the country. In most of the states that have introduced retail competition, NRG Home competitively offers retail power, natural gas, portable power or 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. In the East markets, incumbent utilities currently provide default service and as a result typically serve a majority of residential customers. Regulated terms and conditions of default service, as well as any movement to replace default service with competitive services, as is done in ERCOT, can affect customer participation in retail competition. The attractiveness of NRG Home's offerings in each state may be impacted by the rules, regulations, market structure and communication requirements from public utility commissions across the country.

The NRG Home Solar business operates across an increasing number of states where solar solutions are attractive and price competitive to consumers. As success in the NRG Home 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. For example, many state public service commissions are evaluating changes to their retail rules, including net metering rules, imposition of minimum bills or an increased fixed component to bills, among other potential changes.

Regulatory Matters

As owners 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 CFTC, 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, among other things, has regulatory oversight authority over the trading of swaps, futures and many commodities under the Commodity Exchange Act, or CEA. The Dodd-Frank Act amended the CEA and increased the CFTC's regulatory authority on matters related to futures and over-the-counter derivatives trading like interest rate swaps.

The Company expects that, in 2015 and thereafter, the CFTC will further clarify the scope of the Dodd-Frank Act and publish additional rules concerning margin requirements and other issues that could affect the Company's 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, among other things, regulates 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. 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 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. Generally 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.

Court Rejects FERC’s Jurisdiction Over Demand Response — On May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated FERC’s rules (known as Order No. 745) that allow demand response resources to participate in the FERC-jurisdictional energy markets. The Court of Appeals held that the Federal Power Act does not authorize FERC to exercise jurisdiction over demand response and that instead demand response is part of the retail market over which the states have jurisdiction. The specific order being challenged related to energy market compensation, but this ruling also calls into question whether demand response will be permitted to participate in the capacity markets in the future. The U.S. Court of Appeals for the District of Columbia Circuit issued a stay of its decision in order to allow the U.S. Supreme Court to consider the case. The U.S. Solicitor General, on behalf of FERC, filed a petition for a writ of certiorari on January 15, 2015. On the same date, EnerNOC, Inc. and other private entities filed their own petition for a writ of certiorari in the matter. The Company filed a friend-of-the-court brief with the U.S. Supreme Court on February 17, 2015, supporting the U.S. Solicitor General's and EnerNOC's position and urging the U.S. Supreme Court to grant certiorari. The eventual outcome of this proceeding could result in refunds of payments made for non-jurisdictional services and resettlement of wholesale markets but it is not possible to estimate the impact on the Company at this time.

State Regulation

In Texas, 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.

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. Additionally, the competitiveness of many of NRG's new businesses is dependent on state competition and other policies.

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 only to 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 and 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 Near-Term 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. Among other things, the Task Force required each operator to conduct a review of seismic and flooding risks (beyond the design license basis). STPNOC's analysis confirmed the design adequacy and determined that no other actions are needed with respect to these risks. In conducting its review, STPNOC followed the guidance in the "Seismic Evaluation Guidance: Screening, Prioritization, and Implementation Details (SPID) for the Resolution of Fukushima Near-Term Task Force Recommendation 2.1: Seismic" report published by the Electric Power Research Institute.

Other responsive actions include installation of additional safety-related, redundant cooling systems, hardening 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, all of which are on track to meet the NRC's timetable for completion by the end of 2015. With respect to STP, the estimated total cost for the currently identified required tasks is projected to be less than $40 million, allocated among the three owners, such project being approximately 75% completed by year end in 2014. Until further action is taken by the NRC (including issuance of actions required in response to Tier 2 and 3 recommendations), the Company cannot definitively predict the impact of any additional recommendations by the Task Force and could be required to make additional investments at STP Units 1 and 2.

Nuclear Regulatory Commission Approves Final Rule on Storage of Spent Fuel — On August 26, 2014, the NRC revised its generic determination regarding the environmental impacts of the continued storage of spent nuclear fuel beyond a reactor's licensed life for operation and prior to ultimate disposal and approved a final rule. Upon the effective date of the final rule, the NRC lifted its suspension of final licensing actions on nuclear power plant licenses and renewals.

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

New Jersey and Maryland's Generator Contracting Programs — The New Jersey Board of Public Utilities and the Maryland Public Service Commission awarded long-term power purchase contracts to generation developers to encourage the construction of new generation capacity in the respective States. The constitutionality of the long-term contracts was challenged and the U.S. District Court for the District of New Jersey (in an October 25, 2013, decision) and the U.S. District Court for the District of Maryland (in an October 24, 2013, decision) found that the respective contracts violated the Supremacy Clause of the U.S. Constitution and were preempted. On June 30, 2014, the U.S. Court of Appeals for the Fourth Circuit affirmed the Maryland District Court's decision. On September 11, 2014, the U.S. Court of Appeals for the Third Circuit affirmed the New Jersey District Court's decision. Various parties have petitioned the U.S. Supreme Court for review of both cases. Any U.S. Supreme Court action may affect future capacity prices in PJM.

Capacity Replacement — On March 10, 2014, PJM filed at FERC to limit speculation in the forward capacity auction. Specifically, PJM proposed tariff changes that are designed to ensure that only capacity resources that are reasonably expected to be provided as a physical resource by the start of the delivery year can participate in the Base Residual

Auction. These changes include the addition of a replacement capacity adjustment charge that is intended to remove the incentive to profit from replacing capacity commitments, an increase in deficiency penalties for non-performance, and a reduction in the number of incremental auctions from three to one. On May 9, 2014, FERC rejected PJM's proposed changes to address replacement capacity and incremental auction design, but established a Section 206 proceeding and technical conference to find a just and reasonable outcome. On August 18, 2014, PJM requested that FERC defer further action in the proceeding. Since the request, FERC has taken no action. The Section 206 proceeding and technical conference could have a material impact on future PJM capacity prices.

Capacity Performance Proposal — On December 14, 2014, PJM requested FERC approval to substantially revamp its capacity market. If approved by FERC, future annual capacity auctions would procure two categories of capacity resources: “Capacity Performance” resources and “Base Capacity” resources. Under the proposal, PJM would institute substantial new performance penalties on capacity performance resources that do not perform in real time during specified periods of high demand and substantially modify capacity bidding rules. Should the proposal be approved by FERC, it is likely to have a material impact on future PJM capacity prices.

Capacity Import Limits — On April 22, 2014, FERC approved PJM’s proposal to add a limit on the amount of capacity from external resources that PJM can reliably import into PJM. The capacity import limit will be in effect for the 2017/2018 Base Residual Auction, may decrease the amount of capacity imports allowed into PJM as compared to recent auctions, and could have a material impact on future PJM capacity prices. On January 22, 2015, FERC denied rehearing.

Reactive Power — On November 20, 2014, FERC issued an Order to Show Cause under FPA Section 206 directing PJM to either revise its tariff to provide that a generation or non-generation resource owner will no longer receive reactive power capability payments after it has deactivated its unit and to clarify the treatment of reactive power capability payments for units transferred out of a fleet or show cause why it should not be required to do so. On December 22, 2014, PJM filed proposed tariff changes, and the matter remains pending at FERC. NRG’s reactive power revenues may change as a result of this proceeding.

Recovery of Costs of Capacity Agreements Secured Outside RPM Auctions — On December 24, 2014, PJM submitted proposed revisions to the tariff to permit it to enter into and recover the costs of capacity agreements secured outside the RPM for the specific purpose of alleviating resource adequacy concerns during the 2015/2016 delivery year. On February 20, 2015, FERC rejected PJM's filing without prejudice to PJM refiling a fully specified and justified proposal.

Demand Response Operability — On May 9, 2014, FERC largely accepted PJM’s proposed changes on demand response operability in an attempt to enhance the operational flexibility of demand response resources during the operating day. The approval of these changes will likely limit the amount of demand response resources eligible to participate in PJM. The matter is pending rehearing at FERC.

PJM “Stop Gap” Demand Response Filing — On January 14, 2015, PJM filed to implement “stop gap” rules governing the participation of demand response in the upcoming capacity auction (for the 2018/2019 delivery year), which will take effect only if the U.S. Supreme Court denies certiorari of the EPSA v. FERC decision. Under the new rules, PJM would prohibit demand response from participating in PJM’s capacity auction as supply-side resources. Instead, PJM proposes to create a new product, termed “Wholesale Load Reduction,” that would allow LSEs to bid reductions in demand, backed by physical demand response resources, into the auction. Demand response resources participating as Wholesale Load Reduction would have a comparable impact on capacity clearing prices as demand response participating as supply, on a megawatt for megawatt basis. The Company is opposing PJM’s proposal.

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 England
Performance Incentive Proposal — On January 17, 2014, ISO-NE filed at FERC to revise its forward capacity market, or FCM, by making a resource's FCM 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.

On May 30, 2014, FERC found that most of the provisions in the ISO-NE proposal, with modifications, together with an increase to the reserve constraint penalty factors, provided a just and reasonable structure. FERC instituted a proceeding for further hearings and required ISO-NE to make a compliance filing to modify its proposal and adopt the increases to the reserve constraint penalty factors. The matter is pending rehearing at FERC.

FCM Rules for 2014 Forward Capacity Auction — On February 28, 2014, ISO-NE filed the results of FCA #8 with FERC. On September 16, 2014, FERC issued a notice stating that the FCA #8 results would go into effect by operation of law. Several parties requested rehearing of FERC's notice, which was rejected by FERC on procedural grounds. The matter was appealed to the U.S. Court of Appeals for the District of Columbia Circuit and remains pending.

NEPGA Complaint — On October 31, 2013, NEPGA filed a complaint against ISO-NE alleging that the tariff-set capacity prices during circumstances termed Insufficient Competition and Inadequate Supply and the tariff rules known as the Capacity Carry Forward Rule, components of the FCM, created unreasonable and unduly discriminatory price disparities between new and existing capacity resources. On November 25, 2013, ISO-NE submitted a proposal to raise the tariff-set administrative prices to $7.025/kW-month for Forward Capacity Auction 8. 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. On February 24, 2014, NEPGA filed a request for rehearing. On January 30, 2015, NEPGA's request for rehearing was denied.

Sloped Demand Curve Filing — On May 30, 2014, FERC accepted the proposed tariff revisions discussed in the April 1, 2014 ISO-NE filing at FERC regarding the establishment of a sloped demand curve for use in the ISO-NE Forward Capacity Market. The accepted tariff changes include extending the period during which a market participant can lock-in the capacity price for a new resource from five to seven years, establishing a limited exemption for the buyer-side market mitigation rules for a set amount of renewable resources, and eliminating the administrative pricing rules. The shift away from the current vertical demand curve and accompanying proposed changes could have a material impact on the capacity prices in future auctions. The matter is still subject to rehearing at FERC.

New York

Demand Curve Reset and the Lower Hudson Valley Capacity Zone — On May 27, 2014, FERC denied rehearing and phase-in requests regarding its August 13, 2013 order on the creation of the Lower Hudson Valley Capacity Zone. The NYISO had previously approved the creation of a new Lower Hudson Valley Capacity Zone in New York, as part of the NYISO's triennial adjustment of its capacity market parameters for the 2014-2017 periods. The State of New York, NYSPSC and Central Hudson Gas & Electric Corp. have challenged the FERC order before the U.S. Court of Appeals for the Second Circuit. The U.S. Court of Appeals for the Second Circuit held oral argument on September 12, 2014. The matter remains pending.

NYSPSC Order Rescinding Danskammer Retirement — On October 28, 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 NYSPSC 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. On March 28, 2014, the NYSPSC adopted the October 28, 2013 order as a permanent rule. 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 Reliability Service — On March 14, 2012, 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. As a result of those studies, National Grid 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. Additionally, on July 20, 2012, National Grid and Dunkirk Power agreed on the material terms for a bilateral RSS agreement and submitted those terms to the NYSPSC for rate recovery in National Grid's rates. On August 16, 2012, the NYSPSC approved terms and on August 27, 2012, Dunkirk Power and National Grid entered into the RSS agreement that began on September 1, 2012, and expired on May 31,

2013. In late 2012, National Grid 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.

On July 12, 2012, Dunkirk Power filed a RMR agreement with FERC to protect the Company's interests in the event National Grid and Dunkirk Power could not come to terms on a bilateral agreement for reliability support services. On February 19, 2015, FERC rejected the RMR agreement as unnecessary and clarified in a related docket that it was not intending to review either RSS agreement.

Independent Power Producers of New York Complaint — On May 10, 2013, a generator trade association 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 complaints point to the recent reliability services agreements entered into between the NYSPSC and generators, including Dunkirk Power, as evidence that capacity market prices are being influenced by non-market considerations. The complainants seek to prevent below-cost offers from artificially suppressing prices in the New York Control Area Installed Capacity Spot Market Auction. The case is pending.

On March 25, 2014, the generators filed an Amended Complaint against the NYISO in light of the executed term sheet between Niagara Mohawk Power Corporation d/b/a National Grid and Dunkirk Power, which was filed at NYPSC in February 2014. Under the term sheet, National Grid and Dunkirk Power are to enter into a definitive agreement pursuant to which Dunkirk Power will undertake a gas addition project to enable Units 2-4 to run on natural gas in exchange for payments from National Grid over a 10-year term.

FERC Investigation of NYISO RMR Practices — On February 19, 2015, pursuant to Section 206 of the FPA, FERC found NYISO’s tariff to be unjust and unreasonable because it does not contain provisions governing the retention of and compensation to generating units for reliability. FERC ordered NYISO to adopt tariff provisions containing a proposed RMR rate schedule and pro forma RMR agreement within 120 days of the date of the FERC’s order. However, FERC clarified that NYISO’s RMR proposal will not require Dunkirk to enter into new pro forma agreements for the 2012 and 2013 RSS agreements.

Competitive Entry Exemption to Buyer-Side Mitigation Rules — On December 4, 2014, pursuant to Section 206 of the FPA, a group of New York transmission owners filed a complaint seeking a competitive entry exemption to the current NYISO Buyer-Side Mitigation rules. On December 16, 2014, TDI USA Holdings Corporation filed a complaint under Section 206 against the NYISO claiming that the NYISO’s application of the Mitigation Exemption Test under the Buyer-Side Mitigation Rules to TDI’s Champlain Hudson 1,000 MW transmission line project is unjust and unreasonable and seeks an exemption from the Mitigation Exemption Test. On February 26, 2015, FERC granted the complaint filed by the New York transmission owners and directed the NYISO to adopt a competitive entry exemption into its tariff within 30 days. In a companion order issued on the same day, FERC rejected the TDI complaint on the grounds that TDI’s concerns were adequately addressed by FERC’s first order. Allowing a competitive entry exemption significantly degrades protections against uneconomic entry into the New York markets.

Gulf Coast Region

ERCOT

Houston Import Project — At its April 8, 2014, meeting, the ERCOT Board endorsed a new 345 kV transmission line project designed to address purported reliability challenges related to congestion between north Texas into the Houston region. The proposed project would increase the import capability into the Houston area by adding a new 345 kV double-circuit line to achieve 2,988 MVA of emergency rating for each circuit, upgrading existing substations, and upgrading an existing 345 kV line to achieve 1,450 MVA of emergency rating. The target completion for the proposed project is 2018. On November 14, 2014, the PUCT denied a challenge by the Company and Calpine Corp. regarding ERCOT's endorsement of the project. The transmission owners have not yet initiated the licensing proceedings with the PUCT to obtain the authorization to move forward with the project (Certificate of Convenience and Necessity, or CCN).

Operating Reserve Demand Curve Implementation — At the direction of the PUCT, ERCOT implemented an operating reserve demand curve, known as ORDC, on June 1, 2014. ORDC simulates real-time co-optimization of energy and reserves and uses price adders during scarcity conditions to reflect price formation outcomes expected under real-time co-optimization. Under ORDC, real time energy price could rise to $9,000 per MWh during extreme scarcity events (due to value of lost load assumptions in the price curve), despite the current system wide offer cap of $7,000 per MWh.

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MISO

MISO RMR Practices — 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, or RMR Generators. 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 supported the complaint. On July 22, 2014, FERC issued an Order denying the complaint in part and granting it in part. FERC found that the Tariff was unjust and unreasonable because it did not allow RMR Generators to obtain compensation for their fixed costs. The matter is pending rehearing.

MATS Waiver — Indianapolis Power and Light Company, DTE Electric Company, MidAmerican Energy Company, Duke Energy Indiana, Inc., Consumers Energy Company, and Wisconsin Power & Light Company each separately requested a limited, one-time waiver from their obligations to meet the Resource Adequacy Requirement in the MISO tariff, addressing an approximate six-week gap between the EPA's MATS compliance deadline and the end of MISO's 2015-2016 capacity planning year. The EPA's MATS rules establish limits for HAPs emitted from, among other sources, existing and planned coal-fired generators and go into effect on April 16, 2015. Because the MISO capacity planning year runs from June 1 to May 31, there is a gap between the MATS-driven retirements in April and the MISO planning year in June. Any waiver of an LSE's resource adequacy obligations would have a detrimental effect on the value of capacity in the MISO market.

On October 15, 2014, FERC granted Indianapolis Power and Light Company's request for the limited, one-time waiver of MISO's must-offer requirement and the requirement to purchase replacement capacity for the period of April 16, 2016 to May 31, 2016.

On November 7, 2014, FERC denied without prejudice Consumers Energy's request for a limited waiver on the grounds that Consumers Energy failed to adequately demonstrate that the requested waiver would not cause undesirable consequences, such as harming third-parties. On November 18, 2014, Consumers Energy re-filed its request for a limited waiver. On February, 20, 2014, FERC granted Consumers Energy's request. Also on that day, FERC granted DTE, MidAmerican, and Duke Energy's requests for waivers. Wisconsin Power & Light's request is still pending before FERC. Unlike the other entities' requests of approximately six weeks, Wisconsin Power & Light's request is for a five-month waiver based on a consent decree among the company, the EPA, and the Sierra Club.

Environmental Matters

NRG is subject to a wide range of environmental laws in the development, construction, ownership and operation of projects. 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 GHGs, 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: ESPS/NSPS for GHGs, NAAQS revisions and implementation and effluent guidelines. 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 December 2014, the EPA proposed making the NAAQS for ozone more stringent. The EPA anticipates promulgating a more stringent ozone NAAQS by October 2015. A more stringent NAAQS would obligate the states to develop plans to reduce NO_x (an ozone precursor), which might affect some of the Company's units.
Cross-State Air Pollution Rule — 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 U.S. In September 2011, GenOn and others asked the U.S. Court of Appeals for the D.C. Circuit to stay and vacate CSAPR. In December 2011, the court stayed implementation of CSAPR and ordered the 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 vacated CSAPR but kept CAIR in place. The EPA petitioned the U.S. Supreme Court seeking review of the D.C. Circuit's decision, which petition was granted. On April 29, 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit's decision. In October 2014, the D.C. Circuit lifted the stay of CSAPR. In response, the EPA issued an interim final rule in November 2014 to amend the CSAPR compliance dates. Accordingly, CSAPR replaced CAIR on January 1, 2015. On February 25, 2015, the D.C. Circuit held oral argument regarding several unresolved legal issues, and the Company expects a decision in the second quarter of 2015. While the Company cannot predict the final outcome of the ongoing litigation, the Company believes its investment in pollution controls and cleaner technologies coupled with planned plant retirements should leave the fleet well positioned for compliance.
MATS — In February 2012, the EPA promulgated standards to control emissions of HAPs from coal and oil-fired electric generating units. The rule established limits for mercury, non-mercury metals, certain organics and acid gases, which limits must be met beginning in April 2015 (with some units getting a 1-year extension). In November 2014, the U.S. Supreme Court agreed to review the D.C. Circuit decision that denied the petitions seeking to vacate MATS but the review will be limited to whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric generating units. The oral argument in the Supreme Court is scheduled for March 2015.
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 June 2014, the EPA proposed a rule that would require states to develop CO_2 standards that would apply to existing fossil-fueled generating facilities. Specifically, the EPA proposed state-specific rate-based goals for CO_2 emissions, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. The EPA anticipates finalizing both of these rules in the summer of 2015.
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.

CO_2 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 2012, 2013, and 2014. 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. By 2030, the Company seeks to reduce its CO_2 emissions by 50%, using 2014 as a baseline. The Company's objective is to reduce its CO_2 emissions by 90% by 2050.

Byproducts, Wastes, Hazardous Materials and Contamination

In December 2014, the EPA released a pre-publication version of a final rule that when published in the Federal Register will regulate byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. In 2010, the EPA had proposed two alternatives. Under the first proposal, these byproducts would be regulated as solid wastes. Under the second proposal, these byproducts would have been 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 have imposed significantly more stringent requirements and materially increased the cost of disposal of coal combustion byproducts. The Company is evaluating the impact of the new rule on its results of operations, financial condition and cash flows.

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. Since 1998, the U.S. DOE has been in default of the federal government's obligations to begin accepting 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. Owners of nuclear plants, including the owners of STP, had been required to enter 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 to license a spent fuel repository. Effective May 16, 2014, the U.S. DOE stopped collecting the 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 U.S., 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 is proceeding 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.

Effective October 20, 2014, the NRC issued its Continued Storage of Spent Nuclear Fuel rule that determined that licensees can safely store SNF at nuclear power plants beyond the original and renewed licensed operating life of the plants. The rule remains subject to legal challenges. Upon the effective date of the rule, the NRC lifted its suspension of licensing actions on nuclear power plants.

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 August 2014, EPA finalized the regulation (which had been proposed in 2011) regarding once through cooling from existing facilities to address impingement and entrainment of organisms. NRG anticipates that more stringent requirements will be incorporated into some of its water discharge permits over the next several years. 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 2007, Midwest Generation received an NOV from the EPA alleging that past work at Crawford, Fisk, Joliet, Powerton, Waukegan and Will County generating stations violated NSR and other regulations. These alleged violations are the subject of litigation described in Item 15 — Note 22, Commitments and Contingencies. In January 2009, GenOn received an NOV from the EPA alleging that past work at Keystone, Portland and Shawville generating stations 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 generating stations violated regulations regarding NSR.

In 2008, the PADEP issued an NOV related to the Monarch mine located near the Cheswick generating facility. It has not been mined for many years. The Company's subsidiary discharged approved wastewaters into the Monarch mine including low-volume wastewater from the Cheswick generating facility and leachate collected from ash disposal facilities. The NOV addresses a permit requirement to pump a minimum water volume from the mine. On September 2, 2014, the Company's subsidiary that owns the Cheswick generating facility, the Commonwealth of Pennsylvania and the PADEP entered into a Consent Order and Agreement resolving the NOV. Pursuant to that Consent Order and Agreement, the Company's subsidiary will, among other things, cease wastewater discharges to the mine, construct a waste treatment facility and contribute $200,000 to the Indianola Mine Trust. The Company's subsidiary is currently planning to incur capital expenditures in connection with wastewater from Cheswick and leachate from ash disposal facilities.

In January 2006, NRG's Indian River Power LLC 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 Power LLC 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.

Maryland Environmental Regulations — In October 2014, the MDE released a draft of a proposed regulation regarding NO_x emissions from coal-fired electric generating units. The MDE draft regulation was proposed in the Maryland Register in December 2014. If finalized as proposed, the regulation would require by June 2020 the Company (at each of the three Dickerson coal-fired units and the Chalk Point coal-fired unit that does not have an SCR) to (1) install and operate an SCR; (2) retire the unit; or (3) convert the fuel source from coal to natural gas. The implementation of the MDE regulation could negatively affect certain of the Company’s coal-fired units in Maryland.

RGGI — 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.

Gulf Coast 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 Item 15 — 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 2015 through 2019 required to comply with environmental laws will be approximately $641 million which includes $58 million for GenOn and $464 million for EME. 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; (iii) NO_x controls for Sayreville and

Gilbert; and (iv) DSI/ESP upgrades at Waukegan and Powerton to satisfy the IL CPS and the Joliet gas conversion. 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 Gulf Coast 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.

Customers
NRG sells to a wide variety of customers. No individual customer accounted for 10% or more of NRG's total revenue in 2014. The Company owns and operates power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. The Company also directly sells to end-use customers in the residential, commercial and industrial sectors.

Employees
As of December 31, 2014, NRG had 9,806 employees, approximately 31% of whom were covered by U.S. bargaining agreements. During 2014, 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.nrg.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 2015 and the Company also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so. The Company also sells fixed price gas as a proxy for power. 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 Gulf Coast region, NRG has long-term contracts with rural cooperatives that require it to serve all of the cooperatives' requirements at prices for energy that generally reflect the cost of coal-fired generation. On December 19, 2013, the Entergy region joined the MISO RTO, which employs a two settlement market in which NRG submits bids for energy to cover its load obligations and submits offers to sell energy from its resources. Given the “full requirements” obligation contained in the cooperative contracts, and the possibility of unplanned forced outages of its generation, NRG may be exposed to locational market prices as a net buyer of energy for certain periods, which could have a negative impact on NRG's financial returns from its Gulf Coast region.

NRG's trading operations and 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 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 the Company's 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 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, and 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 CAA, 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 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 also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

In addition, in certain of the markets in which 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 the Company's subsidiaries is a publicly traded corporation, NRG Yield, Inc., which may involve a greater exposure to legal liability than the Company's historic business operations.

One of the Company's subsidiaries is NRG Yield, Inc., a publicly traded corporation. NRG's controlling interest in NRG Yield, Inc. and the position of certain of its executive officers on the Board of Directors 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 NRG's 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. 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. FERC's orders that grant NRG's generating and power marketing companies market-based rate authority reserve the right to revoke or revise that authority if FERC subsequently determines that NRG can exercise market power in transmission or generation, create barriers to entry, or engage in abusive affiliate transactions. In addition, NRG's market-based sales are subject to certain market behavior rules, and if any of NRG's generating and power marketing companies were deemed to have violated one of those rules, they are subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of their market-based rate authority. If NRG's generating and power marketing companies were to lose their market-based rate authority, such companies would be required to obtain FERC's acceptance of a cost-of-service rate schedule and 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.

Substantially all of the Company's generation assets are also subject to the reliability standards promulgated by the designated Electric Reliability Organization (currently NERC) and approved by FERC. If NRG fails to comply with the mandatory reliability standards, NRG could be subject to sanctions, including substantial monetary penalties and increased compliance obligations. 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 non-cash collateral for derivatives transactions and decreasing liquidity in the forward commodity and derivatives markets. The Company expects that, in 2015, 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 NRG's 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.

Certain of NRG's long-term bilateral contracts with state governments could be declared invalid by a court of competent jurisdiction.

A significant portion of NRG's revenues are derived from long-term bilateral contracts with state-regulated utilities. Other state-regulated contracts, to which the Company is not a party, are being challenged in federal court and have been declared unconstitutional on the grounds that the rate for energy and capacity established by the state-regulated contracts impermissibly conflict with the rate for energy and capacity established by FERC. To date, federal district courts in New Jersey and Maryland have struck down contracts on similar grounds. The U.S. Court of Appeals for the Fourth Circuit upheld the Maryland court decision, while the U.S. Court of Appeals for the Third Circuit upheld the New Jersey decision. If certain of the Company's state-regulated agreements with utilities are held to be invalid, the Company may be unable to replace such contracts, which could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

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 — 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 2014 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 June 2014, the EPA proposed a rule that would require states to develop CO_2 standards that would apply to existing fossil-fueled generating facilities. Specifically, the EPA proposed state-specific rate-based goals for carbon dioxide emissions, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. The EPA anticipates finalizing both of these rules in the summer of 2015.

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, 2014, approximately 31% 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. Although NRG's ability to procure such labor is uncertain, contingency staffing planning is completed as part of each respective contract negotiations. 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.

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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, a non-recourse project-level subsidiary or otherwise, 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 including cumulative and forecasted pretax book earnings 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 businesses.

Although NRG is the primary provider of its retail businesses supply requirements, the retail businesses purchase a significant portion of their supply requirements from third parties. As a result, financial performance depends on the 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' 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 businesses.

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 NRG's retail businesses are dependent. Power supply may be sold at a loss if these events cause a significant loss of retail customer load.

NRG Home's retail businesses 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 Home's retail businesses.

NRG Home's retail businesses face competition for customers. Competitors may offer lower prices and other incentives, which may attract customers away from NRG Home's retail businesses. 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, NRG Home's retail businesses 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 Home and its retail businesses.

NRG Home's retail businesses are 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 NRG Home's retail businesses.

NRG Home's retail businesses require 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. NRG Home's retail businesses 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 NRG Home's retail businesses. If a significant breach occurred, the reputation of NRG Home and its retail businesses may be adversely affected, customer confidence may be diminished, or NRG Home and its retail businesses 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.

NRG Home’s business is subject to changing state rules and regulations that could have a material impact on the profitability of its business lines.

NRG Home’s competitiveness is partially dependent on state regulatory policies that establish the structure, rules, terms and conditions on which services are offered to retail customers. These state policies, including net metering or RPS programs, can make it more or less expensive for retail customers to supplement or replace their reliance on grid power, such as with rooftop solar or other NRG Home offerings. NRG Home has limited ability to influence development of these policies and its business model may be more or less effective, depending on changes to the regulatory environment.

The Company has made investments, and may continue to make investments, in new business initiatives predominantly focused on consumer products and in markets that may not be successful, may not achieve the intended financial results or may result in product liability and reputational risk that could adversely affect the Company.

NRG continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. NRG is continuing to pursue investment opportunities in renewables, residential solar, consumer products and distributed generation. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market.

As part of these initiatives, the Company may be liable to customers for any damage caused to customers’ homes, facilities, belongings or property during the installation of Company products and systems, such as residential solar systems and mass market back-up generators. In addition, shortages of skilled labor for Company projects could significantly delay a project or otherwise increase its costs. The products that the Company sells or manufactures may expose the Company to product liability claims relating to personal injury, death, or environmental or property damage, and may require product recalls or other actions. Although the Company maintains liability insurance, the Company cannot be certain that its coverage will be adequate for liabilities actually incurred or that insurance will continue to be available to the Company on economically reasonable terms, or at all. Further, any product liability claim or damage caused by the Company could significantly impair the Company’s brand and reputation, which may result in a failure to maintain customers and achieve the Company’s desired growth initiatives in these new businesses.

The Company's international operations are exposed to political and economic risks, commercial instability and events beyond the Company's control in the countries in which it operates.

The Company's international operations are dependent upon products manufactured, purchased and sold in the U.S. and internationally, including in countries with political and economic instability. In some cases, these countries have greater political and economic volatility and greater vulnerability to infrastructure and labor disruptions than in NRG's other markets. The Company's business could be negatively impacted by adverse fluctuations in freight costs, limitations on shipping and receiving capacity, and other disruptions in the transportation and shipping infrastructure at important geographic points of exit and entry for the Company's products. Operating and seeking to expand business in a number of different regions and countries exposes the Company to a number of risks, including:

- multiple and potentially conflicting laws, regulations and policies that are subject to change;

- imposition of currency restrictions on repatriation of earnings or other restraints;
- imposition of burdensome tariffs or quotas;
- national and international conflict, including terrorist acts; and
- political and economic instability or civil unrest that may severely disrupt economic activity in affected countries.

The occurrence of one or more of these events may negatively impact the Company's business, results of operations and financial condition.

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 GHG 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 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 develop and build new power generation facilities, including new solar projects;
- NRG's ability to implement its strategy;
- NRG's ability to achieve its strategy of regularly returning capital to stockholders;
- NRG's ability to obtain and maintain retail market share;
- NRG's ability to successfully evaluate investments and achieve intended financial results 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, 2014. 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, 2014. The following table summarizes NRG's power production and cogeneration facilities by region:

Name and Location of Facility	Power Market	% Owned[(a)(b)(c)]		Net Generation Capacity (MW) [(d)]	Primary Fuel-type
NRG Business:					
Gulf Coast Region					
Bayou Cove, Jennings, LA	MISO	100.0		225	Natural Gas
Big Cajun I, Jarreau, LA	MISO	100.0		430	Natural Gas
Big Cajun II, New Roads, LA [(e)]	MISO	85.8	[(f)]	1,496	Coal
Cedar Bayou, Baytown, TX	ERCOT	100.0		1,495	Natural Gas
Cedar Bayou 4, Baytown, TX	ERCOT	50.0		249	Natural Gas
Choctaw, French Camp, MS	MISO	100.0		800	Natural Gas
Cottonwood, Deweyville, TX	MISO	100.0		1,263	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
Osceola, Holopaw, FL [(g)]	FRCC	100.0		463	Natural Gas
San Jacinto, LaPorte, TX	ERCOT	100.0		162	Natural Gas
South Texas Project, Bay City, TX [(h)]	ERCOT	44.0		1,176	Nuclear
Sterlington, LA	MISO	100.0		176	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 Gulf Coast Region			15,412	
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 [(e)]	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, Pittsburgh, PA	PJM	100.0		259	Natural Gas
Canal, Sandwich, MA	ISO-NE	100.0		1,112	Oil
Chalk Point, Aquasco, MD [(i)]	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 [(i)]	PJM	100.0	[(b)]	537	Coal
Dickerson, MD	PJM	100.0	[(b)]	312	Natural Gas
Dunkirk, NY [(e)]	NYISO	100.0		75	Coal

Fisk, Chicago, IL	PJM	100.0	197	Oil
Gilbert, Milford, NJ [j]	PJM	100.0	536	Natural Gas

Glen Gardner, NJ [j]	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		410	Coal
Indian River, Millsboro, DE	PJM	100.0		16	Oil
Joliet, IL [e]	PJM	100.0	(c)	1,326	Coal
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 Pittsburg, PA [e]	PJM	100.0		325	Coal
New Castle, West Pittsburg, 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
Portland, Mount Bethel, PA [k]	PJM	100.0		169	Oil
Powerton, Pekin, IL	PJM	100.0	(c)	1,538	Coal
Rockford, IL	PJM	100.0		450	Natural Gas
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 [l]	PJM	100.0	(b)	597	Coal
Shawville, PA	PJM	100.0	(b)	6	Oil
Shelby County, Neoga, IL	MISO	100.0		344	Natural Gas
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
Waukegan, IL	PJM	100.0		689	Coal
Waukegan, IL	PJM	100.0		108	Oil
Werner, South Amboy, NJ [j]	PJM	100.0		212	Oil
Will County, Romeoville, IL	PJM	100.0		761	Coal
	Total net East Region			24,607	
West Region					
Coolwater, Dagget, CA [m]	CAISO	100.0		636	Natural Gas
El Segundo Power, CA	CAISO	100.0		335	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
Midway-Sunset, Fellows, CA	CAISO	50.0		113	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) (n)	CAISO	100.0	188	Natural Gas
Sunrise, Fellows, CA	CAISO	100.0	586	Natural Gas
Walnut Creek, City of Industry, CA	CAISO	100.0	485	Natural Gas
Watson, Carson, CA	CAISO	49.0	204	Natural Gas
	Total net West Region		7,617	
	Total net NRG Business		47,636	

NRG Renew:				
Agua Caliente, Dateland, AZ	CAISO/WECC	51.0	290	Solar
Bingham Lake, MN	MISO	99.0	16	Wind
Broken Bow, NE	MISO	31.0	80	Wind
Buffalo Bear, Buffalo, OK	SPP	100.0	19	Wind
California Valley Solar Ranch, San Luis Obispo County, CA	CAISO/WECC	51.1	128	Solar
Cedro Hill, Bruni, TX	ERCOT	31.0	150	Wind
Community Solar, San Diego State Univ., Bawley, CA	CAISO	100.0	6	Solar
Community Wind North, Lake Benton, MN	MISO	99.0	30	Wind
Crofton Bluffs, NE	MISO	31.0	40	Wind
Crosswinds, Aryshire, IA	MISO	99.0	21	Wind
Distributed Solar	AZNMSNV/WECC	100.0	37	Solar
Eastridge, Lake Wilson, MN	MISO	100.0	10	Wind
Elbow Creek Wind Farm, Howard County, TX	ERCOT	100.0	122	Wind
Elkhorn Ridge, Bloomfield, NE	MISO	67.0	54	Wind
Forward, Berlin, PA	PJM	100.0	29	Wind
Goat Mountain, Sterling City, TX	ERCOT	99.9	150	Wind
Hardin, Jefferson, IA	MISO	99.0	15	Wind
High Lonesome, Willard, NM	MISO	100.0	100	Wind
Ivanpah, Ivanpah Dry Lake, CA	CAISO	50.1	378	Solar
Jeffers, MN	MISO	99.9	50	Wind
Langford Wind Farm, Christoval, TX	ERCOT	100.0	150	Wind
Laredo Ridge, Petersburg, NE	MISO	100.0	80	Wind
Lookout, Berlin, PA	PJM	100.0	38	Wind
Mountain Wind I, Fort Bridger, WY	WECC	31.0	61	Wind
Mountain Wind II, Fort Bridger, WY	WECC	31.0	80	Wind
Odin, NE	MISO	99.9	20	Wind
Pinnacle, Keyser, WV	MISO	100.0	55	Wind
Saint Croix, U.S. Virgin Islands		100.0	5	Solar
San Juan Mesa, Elida, NM	MISO	75.0	90	Wind
Sherbino Wind Farm, Pecos County, TX	ERCOT	50.0	75	Wind
Sleeping Bear, Woodward, OK	SPP	100.0	95	Wind
Spanish Fork, UT	WECC	100.0	19	Wind
Taloga, Putnum, OK	SPP	100	130	Wind
West Pipestone, Pipestone, MN	MISO	98.8	8	Wind
Westridge, Pipestone, MN	MISO	94.5	16	Wind
Wildorado, Vega, TX	ERCOT	99.9	161	Wind
	Total NRG Renew		2,808	
NRG Renew capacity attributable to noncontrolling interest			(630	)
Total net NRG Renew			2,178	
NRG Home Solar:				
Distributed Solar - Residential Solar		100.0	50	Solar
Total net NRG Home Solar			50	
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

Alta Wind, Tehachapi, CA	CAISO	100.0	947	Wind
Blythe, CA	CAISO	100.0	21	Solar

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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
El Segundo Energy Center, CA	CAISO	100.0	550	Natural Gas
GenConn Devon, Milford, CT	ISO-NE	50.0	95	Dual-fuel
GenConn Middletown, CT	ISO-NE	50.0	95	Dual-fuel
High Desert, Lancaster, CA	WECC	100.0	20	Solar
Kansas South, Lemoore, CA	WECC	100.0	20	Solar
Marsh Landing, Antioch, CA	CAISO	100.0	720	Natural Gas
Paxton Creek Cogeneration, Harrisburg, PA	PJM	100.0	12	Natural Gas
Princeton Hospital, NJ (o)	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		2,984	
NRG Yield capacity attributable to noncontrolling interest			(1,334)	
Total net NRG Yield			1,650	
Other Conventional Generation:				
Gladstone Power Station, Queensland, Australia	Enertrade/Boyne Smelter	37.5	605	Coal
Doga, Istanbul, Turkey	Turkey	80.0	144	Natural Gas
	Total net Other		749	
Total generation capacity			54,227	
Total capacity attributable to noncontrolling interest			(1,964)	
Total net generation capacity			52,263	

(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) NRG leases 100% interests in the Powerton facility and Units 7 and 8 of the Joliet facility through facility lease agreements expiring in 2034 and 2030, respectively. NRG owns 100% interest in Joliet Unit 6. NRG operates the Powerton and Joliet facilities.

(d) 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.

(e) 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. NRG intends to add natural gas burning capability to Units 6, 7 and 8 of the Joliet coal facility no later than June 2016.

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

(g) NRG mothballed the Osceola facility (463 MW) effective January 1, 2015.

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

(i) 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.

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

Facility	Expected Deactivation Date	Net Generation Capacity (MW)
Gilbert CT Units 1-4	May 2015	98
Glen Gardner Facility	May 2015	160
Werner Facility	May 2015	210

(k) NRG mothballed Portland coal Units 1 and 2 (401 MW) effective June 1, 2014, and is expected to return those units to service no later than the summer of 2016 using ultra-low sulfur diesel.

(l) NRG intends to mothball the coal-fired Units 1, 2, 3 and 4 at the Shawville generating facility (597 MW) beginning on April 16, 2015, and then return those units to service no later than the summer of 2016 using natural gas.

(m) The Coolwater facility (636 MW) was retired from service on January 1, 2015.

(n) 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.

(o) 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, 2014:

Name and Location of Facility	% Owned		Thermal Energy Purchaser	Megawat Thermal Equivale Capacity (MWt)	Ge Ca
NRG Energy Center Minneapolis, MN	100.0		Approx. 100 steam and 50 chilled water customers	322 136	St 1,1 M Ch wa 38
NRG Energy Center San Francisco, CA	100.0		Approx 175 steam customers	133	St M
NRG Energy Center Omaha, NE	100.0 12.0[(a)] 0%[(a)]	100.0	Approx 60 steam and 60 chilled water customers	142 73 77 26	St M St M Ch wa 22 Ch wa 7,2
NRG Energy Center Harrisburg, PA	100.0		Approx 140 steam and 3 chilled water customers	108 13	St M Ch wa 3,6
NRG Energy Center Phoenix, AZ	0%[(a)] 100.0 12.0[(a)] 0%[(a)]		Approx 35 chilled water customers	4 104 14 28	St M Ch wa 29 Ch wa 3,9 Ch wa 8,0
NRG Energy Center	100.0		Approx 25 steam and	88 46	St M

Pittsburgh, PA		25 chilled water customers		Ch wa 12
NRG Energy Center San Diego, CA	100.0	Approx 15 chilled water customers	26	Ch wa 7,4
NRG Energy Center Dover, DE	100.0	Kraft Foods Inc. and Procter & Gamble Company	66	St M
NRG Energy Center Princeton, NJ	100.0	Princeton HealthCare System	21 17	St M Ch wa 4,7
		Total Generating Capacity (MWt)	1,444	

(a) Capacity of 134 MWt available under the right-to-use provisions contained in agreements between two of NRG Yield Inc.'s thermal facilities and certain of its customers.

Other Properties

NRG owns, net of noncontrolling interest, 101 MW of Distributed Solar facilities, 93 MW of which are 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

Under the Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results within its periodic reports filed with the Securities and Exchange Commission. In accordance with the reporting requirements included in Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, the required mine safety results regarding certain mining safety and health matters are discussed below and are detailed further in Exhibit 95 to this Annual Report on Form 10-K.

In connection with the EME acquisition, NRG acquired a 50% indirect ownership interest in American Bituminous Power Partners, L.P., or Ambit, an operator of coal mines located in Grant Town, West Virginia that are subject to regulation by the Mine Safety and Health Administration, or the MSHA, under the Federal Mine Safety and Health Act, or the Mine Act. On September 23, 2014, Ambit was issued Citation Number 8059310 due to an unsafe means of access for the sixth floor of the prep plant at the Grant Town facility. The citation was issued as Significant & Substantial under Section 104 of the Mine Act and was issued directly to Ambit under its MSHA Mine ID Number (46-08264). On November 7, 2014, NRG completed the sale of its 50% indirect ownership interest in Ambit. As of the date of sale, NRG was unaware of any penalty assessment relating to the citation.

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 authorized 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 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Item 15 — Note 20, Stock-Based Compensation. NRG has also filed with the Secretary of State of Delaware a Certificate of Designation for the 2.822% 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 2014 and 2013 are set forth below:

Common Stock Price	Fourth Quarter 2014	Third Quarter 2014	Second Quarter 2014	First Quarter 2014	Fourth Quarter 2013	Third Quarter 2013	Second Quarter 2013	First Quarter 2013
High	$33.92	$37.39	$38.09	$32.04	$30.28	$29.19	$28.67	$26.51
Low	25.77	28.97	31.50	26.57	26.30	25.24	24.86	22.60
Closing	26.95	30.48	37.20	31.80	28.72	27.33	26.70	26.49
Dividends Per Common Share	$0.14	$0.14	$0.14	$0.12	$0.12	$0.12	$0.12	$0.09

NRG had 336,662,624 shares outstanding as of December 31, 2014. As of January 31, 2015, there were 337,695,251 shares outstanding, and there were 28,100 common stockholders of record.

Dividends

On February 17, 2015, NRG paid a quarterly dividend on the Company's common stock of $0.145 per share, or $0.58 per share on an annualized basis, an increase of 4% from $0.14 per share, or $0.56 per share on an annualized basis. The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws and regulations. The Company expects that, based on current circumstances, comparable cash dividends will continue to be paid in the foreseeable future.

Repurchase of equity securities

For the year ended December 31, 2014	Total number of shares purchased	Average price paid per share[(a)]	Total number of shares purchased under the 2015 Capital Allocation Program	Dollar value of shares that may be purchased under the 2015 Capital Allocation Program[(b)]
December 2014	1,624,360	$26.95	1,624,360	$56,206,970
Year-to-date 2014	1,624,360	$26.95	1,624,360	$56,206,970

(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.

In December 2014, the Company was authorized to repurchase $100 million of its common stock under the 2015 Capital Allocation Program. The purchase of common stock was made using cash on hand. As of December 31 2014, the Company had purchased 1,624,360 shares of NRG common stock for approximately $44 million at an average cost of $26.95 per share. In the first quarter of 2015, the Company purchased an additional 2,224,830 shares of NRG common stock for approximately $56 million at an average cost of $25.25 per share.

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, 2009, through December 31, 2014, 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, 2009 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-2009	Dec-2010	Dec-2011	Dec-2012	Dec-2013	Dec-2014
NRG Energy, Inc.	$100.00	$82.76	$76.75	$98.22	$124.76	$119.18
S&P 500	100.00	115.06	117.49	136.30	180.44	205.14
UTY	100.00	105.41	124.32	123.71	135.73	168.85

Item 6 — Selected Financial Data

The following table presents NRG's historical selected financial data. 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,				
	2014	2013	2012	2011	2010
	(In millions except ratios and per share data)				
Statement of income data:					
Total operating revenues	$15,868	$11,295	$8,422	$9,079	$8,849
Total operating costs and expenses, and other expenses [(a)]	15,752	11,929	8,434	9,725	8,119
Income/(loss) from continuing operations, net [(b)]	132	(352)	315	197	476
Net income/(loss) attributable to NRG Energy, Inc.	$134	$(386)	$295	$197	$477
Common share data:					
Basic shares outstanding — average	334	323	232	240	252
Diluted shares outstanding — average	339	323	234	241	254
Shares outstanding — end of year	337	324	323	228	247
Per share data:					
Net income/(loss) attributable to NRG — basic	$0.23	$(1.22)	$1.23	$0.78	$1.86
Net income/(loss) attributable to NRG — diluted	0.23	(1.22)	1.22	0.78	1.84
Dividends declared per common share	0.54	0.45	0.18	—	—
Book value	$34.67	$32.33	$31.83	$33.71	$32.65
Business metrics:					
Cash flow from operations	$1,510	$1,270	$1,149	$1,166	$1,623
Liquidity position [(c)]	$3,940	$3,695	$3,362	$2,328	$4,660
Ratio of earnings to fixed charges	1.14	0.45	0.84	0.77	2.03
Ratio of earnings to fixed charges and preferred dividends	1.06	0.45	0.83	0.76	1.99
Return on equity	1.15 %	(3.69)%	2.87 %	2.57 %	5.91 %
Ratio of debt to total capitalization	60.41 %	57.60 %	56.74 %	52.43 %	42.94 %
Balance sheet data:					
Current assets	$8,582	$7,596	$7,972	$7,749	$7,137
Current liabilities	4,859	4,204	4,670	5,861	4,220
Property, plant and equipment, net	22,367	19,851	20,153	13,621	12,517
Total assets	40,665	33,902	34,983	26,900	26,896
Long-term debt, including current maturities, capital leases, and funded letter of credit	20,374	16,817	15,883	9,832	10,511
Total stockholders' equity	$11,676	$10,467	$10,269	$7,669	$8,072

(a) The Company recorded impairment losses in 2014 and 2013 as further described in Item 15 — Note 10, Asset Impairments. The Company recorded an impairment loss on its emissions credits of $160 million in 2011.

(b) The Company recorded an impairment loss on its investment in Nuclear Innovation North America LLC of $459 million in 2011 and $2 million in 2012.

(c) 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 $72 million, $63 million, and $271 million as of December 31, 2014, 2013, and 2012, respectively, which represents cash held as collateral from hedge counterparties in support of energy risk management activities. It is the Company's intention to limit the use of these funds for repayment of the related current liability for collateral received in support of energy risk management activities.

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

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions)				
Energy revenue	$7,130	$5,636	$3,738	$3,804	$4,063
Capacity revenue	2,109	1,860	765	750	840
Retail revenue	7,385	6,305	5,900	5,807	5,277
Mark-to-market for economic hedging activities	541	(542)	(418)	325	(199)
Contract amortization	(13)	(31)	(97)	(159)	(195)
Other revenues	556	355	260	342	361
Eliminations	(1,840)	(2,288)	(1,726)	(1,790)	(1,298)
Total operating revenues	$15,868	$11,295	$8,422	$9,079	$8,849

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 businesses, 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 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 2014 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, 2014, 2013, and 2012, and also refer to Item 1 to this Form 10-K for more detailed discussion about the Company's business.

Executive Summary

NRG Energy, Inc., or NRG or the Company, is a competitive power company that produces, sells and delivers energy and energy services in major competitive power markets in the U.S. while positioning itself as a leader in the way residential, industrial and commercial consumers think about and use energy products and services. NRG is leading a customer-driven change in the U.S. energy industry by delivering cleaner and smarter energy choices, while building on the strength of one of the nation's largest and most diverse competitive power portfolios. The Company owns and operates approximately 52,000 MWs of generation; engages in the trading of wholesale energy, capacity and related products around those generation assets; transacts in and trades fuel and transportation services; and directly sells energy, services, and innovative, sustainable products and services to retail customers under the name "NRG" and various other retail brand names owned by NRG.

Business Environment

The industry dynamics and external influences affecting the Company and its businesses, and the power generation and retail energy industry in general in 2014 and for the future medium term include:

Capacity Markets — Capacity markets are a major source of revenue for the Company. Centralized capacity markets exist in ISO-NE, MISO, NYISO and PJM. Bilateral markets exist in CAISO and MISO. 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 NYISO. 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 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 construction 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 and the rules in many of the markets are undergoing significant changes, as discussed in this Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 2014, average natural gas prices at Henry Hub were 21% higher than 2013. 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.

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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. NRG's retail 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 2014, electricity prices in the Company's core markets were generally higher than 2013 primarily due to higher natural gas prices. In 2013, electricity prices in the Company's core markets were generally higher than 2012 primarily due to higher natural gas prices. 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, 2014, 2013, and 2012:

	Average on Peak Power Price ($/MWh) [a]		
Region	2014	2013	2012
Gulf Coast [b]			
ERCOT - Houston	$43.73	$36.40	$28.86
ERCOT - North	43.34	34.63	29.20
MISO - Louisiana Hub [c]	48.72	37.05	33.29
East			
NY J/NYC	71.72	62.94	46.60
NY A/West NY	58.16	46.57	36.28
NEPOOL	75.28	64.02	41.31
PEPCO (PJM)	70.69	47.14	44.12
PJM West Hub	61.15	43.89	40.76
West			
CAISO - NP15	49.27	41.63	33.08
CAISO - SP15	48.39	45.99	35.44

(a) Average on-peak power prices based on real time settlement prices as published by the respective ISOs.
(b) Gulf Coast region also transacts in PJM - West Hub.
(c) Gulf Coast region, south central market 2013 and 2012 price data is "into Entergy". MISO-Louisiana Hub began trading December 2013.

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. Companies are nearly done with their plans to comply by April 2015 although many units have received extensions until April 2016 and the U.S. Supreme Court has agreed to review the rule. 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 U.S. 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 U.S. 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 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, 2014, 2013 and 2012, 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, 2014

Results of Operations and Financial Condition

- EME acquisition — On April 1, 2014, NRG completed the acquisition of EME as discussed in more detail in Item 15 — Note 3, Business Acquisitions and Dispositions.
- Alta Wind acquisition — On August 12, 2014, NRG Yield, Inc. completed the acquisition of Alta Wind as discussed in more detail in Item 15 — Note 3, Business Acquisitions and Dispositions.
- Long-term debt — During 2014, the Company increased its recourse debt by approximately $0.8 billion and increased its non-recourse debt by approximately $2.8 billion primarily in connection with the acquisitions of EME and Alta Wind as well as the issuance of NRG Yield, Inc. corporate debt.
- Impairment losses — During 2014, the Company recognized impairment losses on its Coolwater and Osceola facilities and certain solar panels, as discussed in more detail in Item 15 — Note 10, Asset Impairments.
- NRG Yield, Inc. additional public offering — During the third quarter of 2014, NRG Yield, Inc. completed its second public offering of its Class A common shares at a price of $54 per share, increasing its ownership to 44.7% of NRG Yield LLC, while decreasing NRG's ownership to 55.3% of NRG Yield LLC.

Consolidated Results of Operations
2014 compared to 2013
The following table provides selected financial information for the Company:

	Year Ended December 31,		
(In millions except otherwise noted)	2014[a]	2013	Change %
Operating Revenues			
Energy revenue [b]	$5,422	$3,530	54 %
Capacity revenue [b]	2,087	1,800	16
Retail revenue	7,376	6,300	17
Mark-to-market for economic hedging activities	501	(578)	187
Contract amortization	(13)	(31)	58
Other revenues [c]	495	274	81
Total operating revenues	15,868	11,295	40
Operating Costs and Expenses			
Cost of sales [b]	8,623	6,272	37
Mark-to-market for economic hedging activities	488	(293)	267
Contract and emissions credit amortization [d]	31	33	(6)
Other cost of operations	2,637	2,109	25
Total cost of operations	11,779	8,121	45
Depreciation and amortization	1,523	1,256	21
Impairment losses	97	459	(79)
Selling, general and administrative expense	1,042	904	15
Acquisition-related transaction and integration costs	84	128	(34)
Development costs	91	84	8
Total operating costs and expenses	14,616	10,952	33
Gain on sale of assets	19	—	N/A
Operating Income	1,271	343	271
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	38	7	443
Impairment losses on investments	—	(99)	(100)
Other income, net	22	13	69
Gain on sale of equity-method investment	18	—	N/A
Loss on debt extinguishment	(95)	(50)	90
Interest expense	(1,119)	(848)	32
Total other expense	(1,136)	(977)	16
Income/(Loss) before income taxes	135	(634)	(121)
Income tax expense/(benefit)	3	(282)	(101)
Net Income/(Loss)	132	(352)	(138)
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	34	106
Net income/(loss) attributable to NRG Energy, Inc.	$134	$(386)	(135)
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$4.41	$3.65	21 %

(a) Includes the results of EME from April 1, 2014 to December 31, 2014.
(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

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Management’s discussion of the results of operations for the years ended December 31, 2014, and 2013

Income/(loss) before income tax expense — The pre-tax income of $135 million for the year ended December 31, 2014, compared to a pre-tax loss of $634 million for the year ended December 31, 2013, primarily reflects:

- an increase in gross margin of $1,079 million, including intercompany sales, comprised of an increase in NRG Business gross margin of $479 million, including intercompany sales, an increase in NRG Renew gross margin of $287 million, an increase in NRG Home Retail gross margin of $107 million, an increase in NRG Yield gross margin of $201 million, and an increase in NRG Home Solar gross margin of $5 million;
- a current year increase from net mark-to-market results for economic hedges activity of $298 million;

offset by:

- a net increase in operating expenses of $528 million, primarily related to the acquisition of EME in April 2014; and
- a net increase in other expense of $159 million primarily related to interest expense.

Net income/(loss) — Net income of $132 million compared to net loss in the prior year of $352 million primarily reflects the drivers discussed above.

NRG Business gross margin

The following is a discussion of gross margin for NRG Business, adjusted to eliminate intersegment activity, primarily with NRG Home.

	For the Year Ended December 31, 2014						
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Subtotal	Eliminations	Total
Energy revenue	$2,711	$3,439	$330	$—	$6,480	$ —	$6,480
Capacity revenue	260	1,269	331	—	1,860	—	1,860
Retail revenue	—	—	—	1,868	1,868	—	1,868
Other revenue	86	107	8	189	390	(50)	340
Operating revenue	3,057	4,815	669	2,057	10,598	(50)	10,548
Cost of sales	(1,787)	(2,254)	(266)	(1,831)	(6,138)	—	(6,138)
Gross margin	$1,270	$2,561	$403	$226	$4,460	$ (50)	$4,410
Business Metrics							
MWh sold (in thousands)[(a)]	61,152	49,603	4,769				
MWh generated (in thousands)	59,872	51,292	5,409				
Electricity sales volume — GWh				21,816			
Average customer count (in thousands, metered locations)				82			

	For the Year Ended December 31, 2013						
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Subtotal	Eliminations	Total
Energy revenue	$2,748	$2,439	$148	$—	$5,335	$ —	$5,335
Capacity revenue	375	1,075	265	5	1,720	—	1,720
Retail revenue	—	—	—	1,909	1,909	—	1,909
Other revenue	26	78	3	131	238	(45)	193
Operating revenue	3,149	3,592	416	2,045	9,202	(45)	9,157
Cost of sales	(1,776)	(1,530)	(114)	(1,801)	$(5,221)	—	(5,221)
Gross margin	$1,373	$2,062	$302	$244	$3,981	$ (45)	$3,936
Business Metrics							
MWh sold (in thousands)[(a)]	63,643	34,888	1,534				
MWh generated (in thousands)	57,193	34,081	2,876				
Electricity sales volume — GWh				25,748			
Average customer count (in thousands, metered locations)				99			

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

	Years ended December 31,		
Weather Metrics	Gulf Coast [(c)]	East	West
2014			
CDDs [(b)]	2,737	1,068	1,158
HDDs [(b)]	2,157	5,123	1,712
2013			
CDDs	2,787	1,173	819
HDDs	2,148	4,852	2,272
10 year average			
CDDs	2,885	1,183	786
HDDs	1,866	4,691	2,464

(b) 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.

(c) CDDs/HDDs for the Gulf Coast region represent an average of cumulative population-weighted CDDs/HDDs for Texas and the West South-Central Climate region.

NRG Business gross margin — increased by $479 million, including intercompany sales, during the year ended December 31, 2014, compared to the same period in 2013, due to:

Decrease in Gulf Coast region	$(103	)
Increase in East region	499	
Increase in West region	101	
Decrease in B2B	(18	)
	$479	

The decrease in gross margin in the Gulf Coast region was driven by:

Lower gross margin from a decrease in average realized prices in ERCOT partially offset by higher realized prices in MISO	$(140	)
Lower gross margin from bilateral contracts with load serving entities, including affiliates	(35	)
Higher gross margin from a 16% increase in nuclear generation driven by reduced unplanned outages	35	
Higher gross margin from lower coal transportation costs and lower transmission expenses driven by the move to MISO	30	
Change in commercial optimization activities and other	7	
	$(103	)

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

Higher gross margin due to the EME acquisition in April 2014	$297	
Higher gross margin primarily from a 5% increase in generation and a 6% increase in realized energy prices	127	
Higher gross margin from a 33% increase in New York and New England hedged capacity prices. In New York, the higher prices were driven by the new Lower Hudson Valley Capacity Zone	77	
Lower gross margin from a 7% decrease in PJM hedged capacity prices	(35	)
Changes in commercial optimization activities and other	33	
	$499	

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

Higher gross margin due to the EME acquisition in April 2014	$106	
Higher capacity gross margin due to increases in realized prices	29	
Lower energy gross margin due to a 26% decrease in generation primarily related to out-of-merit dispatch, offset by a 5% increase in price	(17	)
Lower gross margin due to the deactivation of the Contra Costa facility in 2013 and other changes in contracted assets	(23	)
Other	6	
	$101	

The decrease in B2B gross margin was driven by:

Lower C&I gross margin due to lower revenue rates	$(46	)
Higher gross margin due to the acquisition of Energy Curtailment Specialists in August 2013	24	
Other	4	
	$(18	)

NRG Home Retail gross margin

The following is a discussion of gross margin for NRG Home Retail.

Selected Income Statement Data

	Years ended December 31,	
(In millions except otherwise noted)	2014	2013
Operating revenues	$5,505	$4,392
Cost of sales [(a)]	(4,225)	(3,219)
Gross margin	$1,280	$1,173
Business Metrics		
Electricity sales volume — GWh - Gulf Coast	33,284	29,784
Electricity sales volume — GWh - All other regions	8,218	4,363
Average NRG Home customer count (in thousands) [(b)]	2,718	2,190
NRG Home customer count (in thousands) [(b)]	2,844	2,217

(a) Includes intercompany purchases of $1,846 million and $2,097 million, respectively.

(b) Excludes Discrete customers.

- NRG Home Retail gross margin — NRG Home Retail gross margin increased $107 million for the year ended December 31, 2014, compared to the same period in 2013, driven by:

Increase in margins due to higher commodity, home and business services revenues offset by higher supply costs	$92
Increase from the acquisition of Dominion's competitive retail electric business in March 2014	70
Adverse weather impact due to higher supply costs on the incremental weather volumes in 2014 compared to 2013	(55)
	$107

- Trends — Customer counts increased by approximately 627,000 since December 31, 2013 primarily due to the acquisition of the Dominion retail electricity business in Texas and its term contracts with electricity customers in the Northeast. This also created a change in customer mix year over year, with increased volume in the Northeast and an increase in price-sensitive customers in Texas which drove overall unit margins down. Excluding the customers acquired through Dominion, unit margins on the legacy NRG Home Retail business in Texas and the Northeast remained consistent. The Company expects to see continued attrition from the customers on expiring Dominion term contracts in 2015 and to reach a steady state by the end of 2015. Competition and higher supply costs based on forward natural gas prices and higher heat rates could drive lower unit margins in the future. Future unit margins also may be impacted by changes in customer mix by region or customer segment.

NRG Home Solar gross margin

NRG Home Solar gross margin was $9 million in the year ended December 31, 2014 compared to $4 million in the prior year which related primarily to lease revenue from additional solar energy systems that began operating in 2014.

NRG Renew gross margin

	Years ended December 31,	
	2014	2013
(In millions except otherwise noted)		
Operating revenue	$514	$223
Cost of sales	(12)	(8)
Gross margin	$502	$215
Business Metrics		
MWh sold (in thousands)	6,534	2,053
MWh generated (in thousands)	6,992	2,074

NRG Renew had gross margin of $502 million for the year ended December 31, 2014, compared to gross margin of $215 million for the same period in 2013. The increase in gross margin was primarily the result of $157 million related to the EME acquisition in April 2014 as well as $102 million related to the CVSR and Ivanpah projects which reached commercial operations in late 2013 and early 2014, respectively.

NRG Yield gross margin

	Years ended December 31,	
	2014	2013
(In millions except otherwise noted)		
Operating revenue	$601	$380
Cost of sales	(88)	(68)
Gross margin	$513	$312
Business Metrics		
MWh sold (in thousands)[a]	1,552	854
MWht sold (in thousands)[b]	2,060	1,679
MWh generated (in thousands)	3,306	1,585
MWht generated (in thousands)	1,705	1,858

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

(b) Volumes sold do not include MWh of 205 thousand and 139 thousand for thermal generation for the years ended December 31, 2014 and 2013, respectively.

NRG Yield had gross margin of $513 million for the year ended December 31, 2014 compared to gross margin of $312 million for the same period in 2013, which related primarily to $64 million from the acquisition of the Alta Wind Assets in August 2014, $14 million from the acquisition of Energy Systems Company in December 2013 and $108 million as Marsh Landing and El Segundo Energy Center reached commercial operations in 2013.

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 increased by $298 million during the year ended December 31, 2014, compared to the same period in 2013.

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, 2014							
		NRG Business						
	NRG Home	Gulf Coast	East	West	B2B	NRG Renew	Eliminations [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)	$10	$(5)	$—	$1	$(1)	$(1)
Reversal of acquired (gain)/loss positions related to economic hedges	—	—	(325)	1	—	—	—	(324)
Net unrealized gains/(losses) on open positions related to economic hedges	—	510	357	(7)	—	5	(39)	826
Total mark-to-market gains/(losses) in operating revenues	$—	$504	$42	$(11)	$—	$6	$(40)	$501
Mark-to-market results in operating costs and expenses								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(25)	$2	$10	$—	$(2)	$—	$1	$(14)
Reversal of acquired (gain)/loss positions related to economic hedges	(17)	—	11	—	(3)	—	—	(9)
Net unrealized (losses)/gains on open positions related to economic hedges	(295)	(25)	(20)	1	(166)	—	40	(465)
Total mark-to-market (losses)/gains in operating costs and expenses	$(337)	$(23)	$1	$1	$(171)	$—	$41	$(488)

(a) Represents the elimination of the intercompany activity between NRG Home and NRG Business.

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, 2014, the $501 million gain in operating revenues from economic hedge positions was driven by an increase in the value of open positions as a result of decreases in natural gas prices partially offset by the reversal of previously recognized unrealized gains on acquired contracts that settled during the period. The $488 million loss in operating costs and expenses from economic hedge positions was due primarily to a decrease in the value of open positions as a result of decreases in natural gas and 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, 2014, and 2013. 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 and are primarily transacted through BETM.

	Year ended December 31,	
(In millions)	2014	2013
Trading gains/(losses)		
Realized	$136	$66

Unrealized	14	(43)
Total trading gains	$150	$23

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Other Operating Costs

	NRG Business	NRG Home	NRG Home Solar	NRG Renew	NRG Yield	Eliminations	Total
	(in millions)						
Year Ended December 31, 2014	$2,097	$280	$3	$187	$126	$(56)	$2,637
Year Ended December 31, 2013	$1,778	$236	$—	$43	$74	$(22)	$2,109

Other operating costs increased by $528 million for the year ended December 31, 2014, compared to the same period in 2013, due to:

Increase due to the acquisition of EME in April 2014	$326
Increase for CVSR and Ivanpah projects which reached commercial operations in late 2013 and early 2014	83
Increase in Gulf Coast operations and maintenance expense primarily related to the timing and scope of outages at STP and other Texas plants, the acquisition of Gregory in August 2013, as well as fixed asset disposals at STP and the WA Parish and Limestone coal plants in Texas	60
Increase due to the acquisition of Alta Wind and Energy Systems Company	50
Other	9
	$528

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase accounting and the favorable change of $18 million, as compared to 2013, is related primarily to the completion of the roll-off of certain customer contracts acquired in the Reliant acquisition.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $267 million for the year ended December 31, 2014, compared to the same period in 2013, due primarily to the EME acquisition in April 2014, the Alta Wind acquisition in August 2014 and additional depreciation expense of $110 million as a result of El Segundo, Marsh Landing, and Ivanpah reaching commercial operations in late 2013.

Impairment Losses

In 2014, the Company recorded impairment losses of $97 million related primarily to the Osceola and Coolwater facilities as further described in Item 15 — Note 10, Asset Impairments.

In the fourth quarter of 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

Selling, general and administrative expenses is comprised of the following:

	For the year ended December 31,	
(In millions)	2014	2013
Selling and marketing expenses	$347	$312
General and administrative expenses	695	592
	$1,042	$904

- Selling and marketing expenses increased $35 million for the year ended December 31, 2014, compared to the same period in 2013, due primarily to the acquisitions of RDS and Pure Energies, which provided NRG Home Solar with an installation team, internet and telephonic sales team and certain sales channels.
- General and administrative expenses increased $103 million for the year ended December 31, 2014, compared to the same period in 2013, due in part to the acquisition of EME in April 2014 and the expansion of the NRG Home Solar business as well as the presentation of NRG Home Solar expenses as development in 2013.

Acquisition-related Transaction and Integration Costs

NRG incurred transaction and integration costs of $84 million for the year ended December 31, 2014, compared to $128 million for the same period in 2013. The reduction in transaction and integration costs is due primarily to the GenOn integration activities having been substantially completed in 2013, offset by the acquisitions and integration of Alta Wind, Dominion and EME in 2014.

Development Costs

NRG incurred development costs of $91 million for the year ended December 31, 2014, compared to $84 million for the same period in 2013. The increase in development costs relates primarily to an increase in NRG Renew development expenses.

Equity in Earnings of Unconsolidated Affiliates

NRG's equity in earnings of unconsolidated affiliates was $38 million for the year ended December 31, 2014, compared to $7 million for the same period in 2013, due primarily to $13 million of income in the current year from a long-term natural gas hedge entered into by Saguaro in July 2013 compared to losses of $11 million in the prior year, and $13 million resulting from the acquisition of EME in April 2014.

Impairment Losses on Investments

In the fourth quarter of 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.

Gain on Sale of Equity-Method Investment

In the fourth quarter of 2014, the Company sold its investment in Sabine, as described in Item 15 — Note 3, Business Acquisitions and Dispositions. In connection with the sale, the Company received cash proceeds of $35 million and recorded a gain on the sale of $18 million.

Loss on Debt Extinguishment

A loss on debt extinguishment of $95 million was recorded for the year ended December 31, 2014, compared to a loss of $50 million in the year ended December 31, 2013. The loss in 2014 was primarily due to the redemption premiums from the redemption of the 2019 Senior Notes. The loss in 2013 included $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.

Interest Expense

NRG's interest expense increased by $271 million for the year ended December 31, 2014, compared to the same period in 2013 due to the following:

Increase/(decrease) in interest expense	(In millions)
Increase for issuance of 2022 and 2024 Senior Notes in January and April 2014	$116
Reduction to capitalized interest for projects placed in service	102
Decrease for 7.625% and 8.5% Senior Notes due 2019 redeemed in the first, second and third quarters of 2014	(76)
Increase in derivative interest expense primarily for the Alpine interest rate swaps	46
Increase for the acquisition of EME in April 2014	35
Increase for the acquisition of Alta Wind in August 2014	32
Increase for issuance of Yield Convertible Notes and Senior Notes in February and August	23
Decrease for 7.625% GenOn Senior Notes due 2014 redeemed in June 2013	(21)
Increase in amortization of premium/discount	14
Total	$271

Income Tax Expense/(Benefit)

For the year ended December 31, 2014, NRG recorded income tax expense of $3 million on pre-tax income of $135 million. For the same period in 2013, NRG recorded an income tax benefit of $282 million on a pre-tax loss of $634 million. The effective tax rate was 2.2% and 44.5% for the years ended December 31, 2014, and 2013, respectively. For the year ended December 31, 2014, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of PTCs generated from various wind facilities including assets acquired in the EME transaction and a benefit resulting from the recognition of uncertain tax benefits, partially offset by state and local income taxes including a change in the effective state rate.

	Year Ended December 31,	
	2014	2013
	(In millions except as otherwise stated)	
Income/(Loss) Before Income Taxes	$135	$(634)
Tax at 35%	47	(222)
State taxes	9	19
Foreign operations	1	5
Federal and state tax credits, excluding PTCs	(1)	(36)
Valuation allowance	6	(5)
Expiration/utilization of capital losses	—	10
Reversal of valuation allowance on expired/utilized capital losses	—	(10)
Impact of non-taxable entity earnings	(11)	(14)
Net interest accrued on uncertain tax positions	(2)	(3)
Production tax credits	(48)	(14)
Recognition of uncertain tax benefits	(30)	(11)
Tax expense attributable to consolidated partnerships	4	8
Impact of change in effective state tax rate	22	(21)
Other	6	12
Income tax expense/(benefit)	$3	$(282)
Effective income tax rate	2.2%	44.5%

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.

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Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests

Net loss attributable to noncontrolling interests was $2 million for the year ended December 31, 2014, compared to net income attributable to noncontrolling interest of $34 million for the year ended December 31, 2013. During the current year, income attributable to noncontrolling interests in the Ivanpah and Agua Caliente projects and NRG Yield, Inc. were offset by the share of net losses allocated to tax equity investors in the NRG Home Solar and wind tax equity arrangements. This amount was determined as the change in the investors' interests between the beginning and end of each reported period calculated using the hypothetical liquidation at book value, or HLBV, method, less any capital contributions net of any capital distributions. The calculation depends on the specific contractual liquidation provisions of the arrangement and is affected by, among other factors, the tax attributes allocated to the investors including tax bonus depreciation, PTCs, ITCs or U.S. Treasury grants in lieu of the ITCs, the existence of guarantees of minimum returns to the investors by NRG, and the allocation of tax income or losses including provisions that govern the level of deficits that can be funded by the investors in a liquidation scenario.

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	6,300	5,900	7
Mark-to-market for economic hedging activities	(578)	(450)	(28)
Contract amortization	(31)	(97)	68
Other revenues [c]	274	193	42
Total operating revenues	11,295	8,422	34
Operating Costs and Expenses			
Cost of sales [b]	6,272	4,951	27
Mark-to-market for economic hedging activities	(293)	(182)	(61)
Contract and emissions credit amortization [d]	33	39	(15)
Other cost of operations	2,109	1,332	58
Total cost of operations	8,121	6,140	32
Depreciation and amortization	1,256	950	32
Impairment losses	459	—	N/A
Selling, general and administrative expense	904	807	12
Acquisition-related transaction and integration costs	128	107	20
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)	N/A
Income tax benefit	(282)	(327)	(14)
Net Income	(352)	315	(212)
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	34	20	70
Net 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 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, 2013 and 2012

NRG Business gross margin

The following is a discussion of gross margin for NRG Business, adjusted to eliminate intersegment activity, primarily with NRG Home.

	For the Year Ended December 31, 2013						
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Subtotal	Eliminations	Total
Energy revenue	$2,748	$2,439	$148	$—	$5,335	$ —	$5,335
Capacity revenue	375	1,075	265	5	1,720	—	1,720
Retail revenue	—	—	—	1,909	1,909	—	1,909
Other revenue	26	78	3	131	238	(45)	193
Operating revenue	3,149	3,592	416	2,045	9,202	(45)	9,157
Cost of sales	(1,776)	(1,530)	(114)	(1,801)	(5,221)	—	(5,221)
Gross margin	$1,373	$2,062	$302	$244	$3,981	$ (45)	$3,936
Business Metrics							
MWh sold (in thousands)[(a)]	63,643	34,888	1,534				
MWh generated (in thousands)	57,193	34,081	2,876				
Electricity sales volume — GWh				25,748			
Average customer count (in thousands, metered locations)				99			

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

	Year Ended December 31, 2012						
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Subtotal	Eliminations	Total
Energy revenue	$2,929	$537	$121	$1	$3,588	$ —	$3,588
Capacity revenue	318	317	124	6	765	—	765
Retail revenue	—	—	—	1,907	1,907	—	1,907
Other revenue	18	19	4	85	126	(17)	109
Revenue	3,265	873	249	1,999	6,386	(17)	6,369
Cost of sales	(1,474)	(443)	(88)	(1,738)	(3,743)		(3,743)
Gross margin	$1,791	$430	$161	$261	$2,643	$ (17)	$2,626
Business Metrics							
MWh sold (in thousands)[(a)]	57,370	6,516	2,011				
MWh generated (in thousands)	49,642	5,205	2,011				
Electricity sales volume — GWh				26,745			
Average customer count (in thousands, metered locations)				84			

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

	Year Ended December 31,		
Weather Metrics	Gulf Coast [(c)]	East	West
2013			
CDDs [(b)]	2,787	1,173	819
HDDs [(b)]	2,148	4,852	2,272
2012			
CDDs	2,458	754	904
HDDs	2,157	5,317	2,988
10 year average			

CDDs	2,859	1,168	792
HDDs	1,886	4,727	2,483

(b) 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.
(c) CDDs/HDDs for the Gulf Coast region represent an average of cumulative population-weighted CDDs/HDDs for Texas and the West South-Central Climate region.

NRG Business gross margin — increased by $1,338 million, including intercompany sales, during the year ended December 31, 2013, compared to the same period in 2012, due to:

Decrease in Gulf Coast region	$(418)
Increase in East region	1,632
Increase in West region	141
Decrease in B2B	(17)
	$1,338

The decrease in gross margin in the Gulf Coast region was driven by:

Lower gross margin from a decrease in average realized prices	$(469)
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 from the acquisition of GenOn in December 2012	25
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	(21)
	$(418)

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

Higher gross margin from the acquisition of GenOn in December 2012	$1,547
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)
	1,632

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

Higher gross margin from the acquisition of GenOn in December 2012	$169
Lower gross margin due to a decrease in capacity prices	(32)
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	9
Lower gross margin due to new California emissions program	(11)
Change in unrealized commercial optimization activities and other	6
	$141

NRG Home Retail gross margin

The following is a discussion of gross margin for NRG Home Retail.

Selected Income Statement Data

	Years ended December 31,	
(In millions except otherwise noted)	2013	2012
Operating revenues	$4,392	$3,993
Cost of sales [(a)]	(3,219)	(2,788)
Gross margin	$1,173	$1,205
Business Metrics		
Electricity sales volume — GWh - Gulf Coast	29,784	29,063
Electricity sales volume — GWh - All other regions	4,363	3,352
Average NRG Home customer count (in thousands) [(b)]	2,190	2,078
NRG Home customer count (in thousands) [(b)]	2,217	2,149

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

(b) Excludes Discrete customers.

- NRG Home Retail gross margin — NRG Home Retail gross margin decreased $32 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	$(56)
Increase in customer count and usage	53
Milder weather in 2013 as compared to 2012	(29)
	$(32)

- Trends — Customer counts increased by approximately 68,000 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.

NRG Home Solar gross margin

Gross margin for NRG Home Solar was $4 million in the year ended December 31, 2013 compared to $3 million in the prior year driven by a year over year increase in leases deployed.

NRG Renew gross margin

	Years ended December 31,	
	2013	2012
(In millions except otherwise noted)		
Operating revenue	$223	$122
Cost of sales	(8)	—
Gross margin	$215	$122
Business Metrics		
MWh sold (in thousands)[(a)]	2,053	1,377
MWh generated (in thousands)	2,074	1,375

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

NRG Renew had gross margin of $215 million for the year ended December 31, 2013, compared to gross margin of $122 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

	Years ended December 31,	
	2013	2012
(In millions except otherwise noted)		
Operating revenue	$380	$176
Cost of sales	(68)	(58)
Gross margin	$312	$118
Business Metrics		
MWh sold (in thousands)	854	422
MWht sold (in thousands)[(a)]	1,679	1,517
MWh generated (in thousands)	1,585	422
MWht generated (in thousands)	1,858	1,098

(a) Volumes sold do not include MWh of 139 thousand and 88 thousand for thermal generation for the years ended December 31, 2014 and 2013, respectively.

NRG Yield had gross margin of $312 million for the year ended December 31, 2013 compared to gross margin of $118 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, El Segundo Energy Center and Marsh Landing.

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 in 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 are as follows:

	Year Ended December 31, 2013							
		NRG Business						
	NRG Home	Gulf Coast	East	B2B	West	NRG Renew	Elimination [(a)]	Total
	(In millions)							
Mark-to-market results in operating revenues								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$—	$(291)	$(4)	$(6)	$(3)	$—	$ (11)	$(315)
Reversal of acquired gain positions	—	—	(401)	—	(2)	—	—	$(403)
Net unrealized gains/(losses) on open positions related to economic hedges	—	119	39	1	7	(1)	(25)	140
Total mark-to-market (losses)/gains in operating revenues	$—	$(172)	$(366)	$(5)	$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	$38	$42	$13	$106	$—	$—	$ 11	$210
Reversal of acquired loss positions	—	—	40	6	—	—	—	46
Net unrealized gains/(losses) on open positions related to economic hedges	15	20	(11)	(9)	—	—	22	37
Total mark-to-market gains in operating costs and expenses	$53	$62	$42	$103	$—	$—	$ 33	$293

(a) Represents the elimination of the intercompany activity between NRG Home and NRG Business.

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 years ended December 31, 2013, and 2012. 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,	
	2013	2012
	(In millions)	
Trading gains/(losses)		
Realized	$66	$83
Unrealized	(43)	(14)
Total trading gains	$23	$69

Other Operating Costs

	NRG Business	NRG Home	NRG Renew	NRG Yield	Eliminations	Total
	(in millions)					
Year Ended December 31, 2013	$1,778	$236	$43	$74	$(22)	$2,109
Year Ended December 31, 2012	$1,087	$241	$15	$54	$(65)	$1,332

Other operating costs increased by $777 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 NRG Renew and NRG Yield as projects reached commercial operations in 2013	24
Other	4
	$777

Contract Amortization Revenue

Contract amortization represents the roll-off of in-market customer contracts valued under purchase 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.

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 of 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

Selling, general and administrative expenses is comprised of the following:

	For the year ended December 31,	
(In millions)	2013	2012
Selling and marketing expenses	$312	$303
General and administrative expenses	592	504
	$904	$807

General and administrative expenses increased $88 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

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 of 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:

	(In millions)
Increase/(decrease) in interest expense	
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 PTCs generated from Gulf Coast 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	19	1
Foreign operations	5	(24)
Federal and state tax credits, including ITCs	(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	—
Impact of change in effective state tax rate	(21)	(12)
Other	12	1
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.

Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests

Net income attributable to noncontrolling interests was $34 million for the year ended December 31, 2014, compared to $20 million for the year ended December 31, 2012, which related primarily to noncontrolling interests in the Agua Caliente project which reached commercial operation in 2013 and NRG Yield, Inc., resulting from its public offering in 2013.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2014 and 2013, NRG's liquidity, excluding collateral received, was approximately $3.9 billion and $3.7 billion, respectively, comprised of the following:

	As of December 31,	
	2014	2013
	(In millions)	
Cash and cash equivalents	$2,116	$2,254
Restricted cash	457	268
Total	2,573	2,522
Total credit facility availability	1,367	1,173
Total liquidity, excluding collateral received	$3,940	$3,695

For the year ended December 31, 2014, total liquidity, excluding collateral received, increased by $245 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, 2014 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

Of the $2.1 billion of cash and cash equivalents of the Company as of December 31, 2014, $157 million and $322 million were held by GenOn Mid-Atlantic and REMA, respectively. 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 GenOn 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. In addition, prior to making a dividend or other restricted payment, REMA must be in compliance with the requirement to provide credit support to the owner lessors securing its obligation to pay scheduled rent under its leases. Based on GenOn Mid-Atlantic's and REMA's most recent calculations of these tests, GenOn Mid-Atlantic and REMA did not satisfy the restricted payments tests. As a result, as of December 31, 2014, GenOn Mid-Atlantic and REMA could not make distributions of cash and certain other restricted payments. Each of GenOn Mid-Atlantic and REMA may recalculate its fixed charge coverage ratios from time to time and, subject to compliance with the restricted payments test described above, make dividends or other restricted payments.

To the extent GenOn Mid-Atlantic or REMA are able to pay dividends to GenOn, 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, 2014, GenOn met the consolidated debt ratio component of the restricted payments test. If in the future, GenOn is unable to meet the consolidated debt ratio of component of the restricted payments test, GenOn's ability to make restricted payments, including dividends, loans and advances to NRG, is limited to specific 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, GenOn Americas Generation Senior Notes, and NRG Yield, Inc. as of December 31, 2014:

	S&P	Moody's
NRG Energy, Inc.	BB- Stable	Ba3 Stable
7.625% Senior Notes, due 2018	BB-	B1
8.25% Senior Notes, due 2020	BB-	B1
7.875% Senior Notes, due 2021	BB-	B1
6.25% Senior Notes, due 2022	BB-	B1
6.625% Senior Notes, due 2023	BB-	B1
6.25% Senior Notes, due 2024	BB-	B1
Term Loan Facility, due 2018	BB+	Baa3
GenOn 7.875% Senior Notes, due 2017	B	B3
GenOn 9.500% Senior Notes, due 2018	B	B3
GenOn 9.875% Senior Notes, due 2020	B	B3
GenOn Americas Generation 8.500% Senior Notes, due 2021	B	Caa1
GenOn Americas Generation 9.125% Senior Notes, due 2031	B	Caa1
NRG Yield, Inc.	BB+ Stable	Ba1 Stable

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, which could be funded with additional debt or equity issuances. 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, the NRG Yield Convertible Notes, the Yield Operating senior unsecured notes, the NRG Yield, Inc. revolving credit facility, and project-related financings.

Issuance of 2022 and 2024 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, which began 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 was used to finance the EME acquisition.

On April 21, 2014, NRG issued $1.0 billion in aggregate principal amount at par of 6.25% Senior Notes due 2024. The notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest is payable semi-annually, which began on November 1, 2014, until the maturity date of May 1, 2024. A portion of the cash proceeds was used to redeem all remaining of its 7.625% 2019 Senior Notes, and the rest of the proceeds were used to redeem the remaining $225 million of its 8.5% 2019 Senior Notes in September 2014.

Cash Proceeds from NRG Yield, Inc. Class A Common Stock, Senior Unsecured Notes and Convertible Notes

In order to fund the purchase price of the acquisition of the Alta Wind facilities, as discussed further in Item 15 — Note 3, Business Acquisitions and Dispositions, to the Consolidated Financial Statements, NRG Yield, Inc. issued 12,075,000 shares of its Class A common stock on July 29, 2014 for net proceeds of $630 million. In addition, on August 5, 2014, Yield Operating issued $500 million in aggregate principal amount at par of 5.375% senior notes due August 2024. Interest on the notes is payable semi-annually on February 15 and August 15 of each year, and commenced on February 15, 2015. The notes are senior unsecured obligations of Yield Operating and are guaranteed by NRG Yield LLC, Yield Operating's parent company, and by certain of Yield Operating's wholly owned current and future subsidiaries.

In the first quarter of 2014, NRG Yield, Inc. closed on its offering of $345 million aggregate principal amount of 3.50% Convertible Senior Notes due 2019, or the NRG Yield Convertible Notes. The NRG Yield Convertible Notes are convertible, under certain circumstances, into NRG Yield, Inc. Class A 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 Convertible Notes. The proceeds from the issuance were used to fund the purchase of High Desert, Kansas South and El Segundo Energy Center, which were acquired from NRG on June 30, 2014.

Cash Proceeds from Residential Solar Financing Arrangements

NRG has entered into various arrangements to monetize the tax attributes of residential solar assets subject to lease and power purchase agreements. As of December 31, 2014, the Company has received approximately $51 million in funding related to these arrangements and has $137 million of availability for future funding under these arrangements.

Cash Proceeds from Wind Tax Equity Arrangement

On November 3, 2014, the Company sold an economic interest in a portfolio of wind assets for gross proceeds of approximately $195 million, in order to monetize cash and tax benefits associated with the projects. The Company will continue to manage the portfolio of wind assets, which were primarily acquired in connection with the acquisition of EME, and will continue to consolidate the assets, with the contributions presented as noncontrolling interests in the Company's consolidated balance sheet.

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

On January 2, 2015, NRG Yield, Inc. acquired the following NRG entities: (i) WCEP Holdings, LLC, which indirectly owns Walnut Creek, (ii) Tapestry Wind LLC, which indirectly owns Pinnacle, Buffalo Bear and Taloga, and (iii) Mission Wind Laredo, LLC, which indirectly owns Laredo Ridge, for total cash consideration of $489 million, including adjustments for working capital, plus assumed project level debt of $737 million,

On January 15, 2015, the Company disclosed its intentions to continue to significantly invest in its residential and distributed generation solar businesses. Given the long-term contracted and operating nature of these businesses, the associated assets could also be deemed eligible for an investment opportunity offer to NRG Yield, Inc. If an investment opportunity is offered to NRG Yield, Inc., it could represent an incremental source of liquidity for the Company.

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of the Company's assets, excluding assets acquired in the GenOn and EME (Midwest Generation) acquisitions, assets held by NRG Yield, Inc. 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 first lien program. The first 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 first lien counterparties may have a claim on its assets to the extent market prices exceed the hedged prices. As of December 31, 2014, all hedges under the first liens were in-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, 2014:

Equivalent Net Sales Secured by First Lien Structure [a]	2015	2016	2017	2018
In MW [b]	700	1,004	309	—

As a percentage of total net coal and nuclear capacity [c]	12 %	17 %	5 %	— %

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.
(b) 2015 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, 2014, commercial operations had total cash collateral outstanding of $187 million, and $746 million outstanding in letters of credit to third parties primarily to support its commercial activities for both wholesale and retail transactions (includes a $42 million letter of credit relating to deposits at the PUCT that cover outstanding customer deposits and residential advance payments). As of December 31, 2014, total collateral held from counterparties was $72 million in cash, and $8 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 Grants

As of December 31, 2014, the Company had no outstanding cash grant bridge loans to be paid from proceeds received under the 1603 Cash Grant Program. Since December 31, 2013, excluding CVSR, the Company has received the following cash grants as of December 31, 2014, the related 1603 cash grant proceeds of which were used to repay all outstanding cash grant bridge loans:

Project:	Application Amount	Sequestration Amount	Additional Reduction By U.S. Treasury [(a)]	Pending Review By U.S. Treasury[(b)]	Amount Received
	(In millions)				
Solar Partners I (Ivanpah)	$196	$14	$—	$18	$164
Solar Partners II (Ivanpah)	189	14	—	18	157
Solar Partners VIII (Ivanpah)	196	14	—	18	164
Alpine	72	5	—	—	67
Borrego	39	2	6	—	31
Lincoln Financial Field	6	—	1	—	5
Kansas South	23	2	—	—	21
High Desert	25	1	4	—	20
Total	$746	$52	$11	$54	$629

(a) The Company has booked a reserve against the total remaining receivable balance for these projects in the amount of $11 million pending further discussions with U.S. Treasury.

(b) The Company has received questions and requests for additional documentation from the U.S. Treasury for the remaining 10% of the Ivanpah cash grant awards for which the Company believes the outstanding amount to be valid and recoverable in 2015.

As of December 31, 2014, the Company had a net renewable energy grant receivable of $135 million, including $54 million for Ivanpah, net of sequestration, and $75 million receivable pursuant to an indemnity agreement the Company has with SunPower Corporation, Systems, or SunPower, relating to the CVSR project. In January 2014, the Company was awarded a cash grant from the U.S. Treasury Department in the amount of $285 million for the CVSR solar project. The amount received reflects the application amount of $414 million less a reduction by Treasury of

$107 million and a sequestration adjustment of $22 million. NRG maintains a receivable, net of sequestration, of $107 million, for which the Company has reserved $32 million of the balance. Pursuant to the purchase and sale agreement for the CVSR project between NRG and SunPower, SunPower agreed to indemnify NRG up to $75 million if Treasury made certain determinations and awarded a reduced 1603 cash grant for the project. SunPower has refused to honor its contractual indemnification obligation. As a result, on March 19, 2014, NRG filed a lawsuit against SunPower in California state court, alleging breach of contract and also seeking a declaratory judgment that SunPower has breached its indemnification obligation. NRG is seeking $75 million in damages from SunPower. NRG believes it has complied with all material obligations under the 1603 Cash Grant Program and is actively pursuing indemnification and is working with the U.S. Treasury Department to obtain payment on the remaining 1603 applications the Company or its subsidiaries have submitted.

Debt Service Obligations

Principal payments on debt and capital leases as of December 31, 2014, are due in the following periods:

Description	2015	2016	2017	2018	2019	Thereafter	Total
	(In millions)						
NRG Recourse Debt:							
Senior notes, due 2018	$—	$—	$—	$1,130	$—	$—	$1,130
Senior notes, due 2020	—	—	—	—	—	1,063	1,063
Senior notes, due 2021	—	—	—	—	—	1,128	1,128
Senior notes, due 2022	—	—	—	—	—	1,100	1,100
Senior notes, due 2023	—	—	—	—	—	990	990
Senior notes, due 2024	—	—	—	—	—	1,000	1,000
Term loan facility, due 2018	20	20	20	1,927	—	—	1,987
Tax-exempt bonds	11	—	—	—	—	395	406
Subtotal NRG Recourse Debt	31	20	20	3,057	—	5,676	8,804
NRG Non-Recourse Debt:							
GenOn senior notes	—	—	725	674	—	550	1,949
GenOn Americas Generation senior notes	—	—	—	—	—	850	850
GenOn - Other	5	4	4	3	3	41	60
Subtotal GenOn debt (non-recourse to NRG)	5	4	729	677	3	1,441	2,859
NRG Yield Operating LLC senior notes, due 2024	—	—	—	—	—	500	500
NRG Yield Inc. convertible senior notes, due 2019	—	—	—	—	345	—	345
NRG West Holdings LLC, term loan, due 2023	36	41	41	47	49	292	506
NRG Marsh Landing term loan, due 2017 and 2023	46	48	52	55	57	206	464
Alta Wind I- V lease financing arrangements, due 2034 and 2035	35	37	39	40	42	843	1,036
Alta Wind X, due 2020	—	13	13	13	13	248	300
Alta Wind XI, due 2020	—	8	9	8	9	157	191
NRG Solar Alpine LLC, due 2022	9	9	9	8	8	120	163
NRG Energy Center Minneapolis LLC, senior secured notes due 2017 and 2025	12	12	13	8	11	65	121
NRG Yield- other	22	23	24	23	23	328	443
Subtotal NRG Yield debt (non-recourse to NRG)	160	191	200	202	557	2,759	4,069
Ivanpah Financing, due 2015, 2033 and 2038	33	37	39	41	42	995	1,187
Agua Caliente Solar, LLC, due 2037	29	30	31	32	32	744	898
CVSR - High Plains Ranch II LLC, due 2037	21	21	23	26	24	700	815
Walnut Creek, term loans due 2023	39	41	43	45	47	176	391
Viento Funding II, Inc., due 2023	8	11	14	16	18	129	196
Tapestry Wind LLC, due 2023	11	9	10	11	11	140	192
NRG Peaker Finance Co. LLC, bonds, due 2019	31	33	35	7	—	—	106
Cedro Hill Wind LLC, due 2025	7	6	10	10	9	69	111
NRG - other	98	29	55	15	22	285	504
Subtotal NRG non-recourse debt	277	217	260	203	205	3,238	4,400
Subtotal non-recourse debt (including GenOn and NRG Yield)	442	412	1,189	1,082	765	7,438	11,328
Subtotal long-term debt	473	432	1,209	4,139	765	13,114	20,132

Capital Lease:							
Chalk Point capital lease, due 2015	5	—	—	—	—	—	5
Other Capital Leases	—	—	—	1	1	1	3
Subtotal NRG Capital Leases	5	—	—	1	1	1	8
Total Debt and Capital Leases	$478	$432	$1,209	$4,140	$766	$13,115	20,140

In addition to the debt and capital leases shown in the preceding table, NRG had issued $1.1 billion of letters of credit under the Company's $2.5 billion Revolving Credit Facility as of December 31, 2014.

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, 2014, and the estimated capital expenditure and growth investments forecast for 2015.

	Maintenance	Environmental	Growth Investments	Total
	(In millions)			
NRG Business				
Gulf Coast	$109	$106	$9	$224
East	133	148	8	289
West	3	—	—	3
B2B	6	—	8	14
NRG Home Retail	35	—	—	35
NRG Home Solar	—	—	112	112
NRG Renew	—	—	147	147
Yield	8	—	25	33
Corporate	39	—	13	52
Total cash capital expenditures for the year ended December 31, 2014	333	254	322	909
Other investments[(a)]	—	—	141	141
Funding from debt financing, net of fees	(24)	—	(173)	(197)
Funding from third party equity partners	(8)	—	(219)	(227)
Total capital expenditures and investments, net	301	254	71	626
Estimated capital expenditures for 2015	513	349	1,221	2,083
Other investments[(a)]	—	—	133	133
Funding from debt financing, net of fees	(31)	—	(67)	(98)
Funding from third party equity partners	(12)	—	(387)	(399)
NRG estimated capital expenditures for 2015, net of financings	$470	$349	$900	$1,719

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

- Maintenance and Environmental capital expenditures — For the year ended December 31, 2014, the Company's environmental capital expenditures included $123 million related to controls to satisfy MATS and NSR settlement at the Big Cajun II facility and NO_x controls for the Sayreville and Gilbert facilities.
- Growth Investments capital expenditures — For the year ended December 31, 2014, the Company's growth investment expenditures included $256 million for solar projects and $66 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 2015 through 2019 required to comply with environmental laws will be approximately $641 million, which includes $58 million for GenOn and $464 million for EME. 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; (iii) NO_x controls for Sayreville and Gilbert; and (iv) plant modifications to comply with environmental regulations at the Powerton, Joliet and Waukegan plants acquired in the EME acquisition. 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 Gulf Coast 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]	State	SO_2 Control Equipment	Install Date	NO_x Control Equipment	Install Date	Mercury Control Equipment	Install Date	Particulate Control Equipment	Install Date
Big Cajun II 1	LA	DSI	2015	LNBOFA/ SNCR	2005/2014	ACI	2015	ESP/upgrade	1981/20
Big Cajun II 2	LA	Gas Conversion	2015	LNBOFA/ SNCR	2004/2014	Gas Conversion	2015	Gas Conversion	2015
Big Cajun II 3	LA	PAL	2013	LNBOFA/ SNCR	2002/2014	ACI	2015	ESP/upgrade	1983/20
Chalk Point 1	MD	FGD	2009	SCR	2008	FGD/ESP	2009	ESP/upgrade	1964/19
Chalk Point 2	MD	FGD	2009	SACR	2006	FGD/ESP	2009	ESP/upgrade	1964/19
Cheswick 1	PA	FGD	2010	SCR	2003	FGD/ESP	2010	ESP	1970
Conemaugh 1-2	PA	FGD	1994, 95	SCR	2014	FGD/ESP/SCR	1994,95/ 2015	ESP	1970, 19
Dickerson 1-3	MD	FGD	2009	SNCR	2009	FGD/FF	2009	ESP/FF	1959,19 1962/20
Dunkirk 1-4	NY	DSI/FF	2009-10	LNBOFA/SNCR	1993,94/ 2009,10	ACI	2009/10	FF	2009/10
Huntley 68	NY	DSI/FF	2009	LNBOFA/SNCR	1995/2009	ACI	2009	FF	2009
Indian River 4	DE	CDS	2011	LNBOFA/SCR	1999/2011	ACI	2008	ESP/FF	1980/20
Joliet 6	IL	Gas Conversion	2016	OFA/SNCR	2000/2012	ACI	2009	ESP	1959
Joliet 7,8	IL	Gas Conversion	2016	LNBOFA/SNCR	2000,01/ 2012	ACI	2009	ESP	1965,66
Keystone 1-2	PA	FGD	2009	SCR	2003	FGD/ESP	2009	ESP	1967, 19
Limestone 1-2	TX	FGD	1985-86	LNBOFA/ SNCR	2002/2018,2019	ACI	2015	ESP	1985-19
Morgantown 1-2	MD	FGD	2009	SCR	2007-2008	FGD/ESP	2009	ESP	1970, 19
Powerton 5	IL	DSI	2016	OFA/SNCR	2003/2012	ACI	2009	ESP/upgrade	1973/20
Powerton 6	IL	DSI	2014	OFA/SNCR	2002/2012	ACI	2009	ESP/upgrade	1976/20
Seward	PA	FBL/CDS	2004	SNCR	2004	FBL/FF	2004	FF	2004
W.A. Parish 5, 6, 7	TX	FF co-benefit	1988	SCR	2004	ACI	2015	FF	1988
W.A. Parish 8	TX	FGD	1982	SCR	2004	ACI	2015	FF	1988
Waukegan 7	IL	DSI	2014	LNBOFA	2002	ACI	2008	ESP/upgrade	1958/20 2014
Waukegan 8	IL	DSI	2015	LNBOFA	1999	ACI	2008	ESP/upgrade	1962/19 2015
	IL	None	None	LNBOFA/SNCR	1999,2001/	ACI	2009	ESP/upgrade	1963,72/

Will County 3, 4	2012	2000

(a) NRG plans to add natural gas capabilities at its Avon Lake, New Castle, Shawville, Joliet, Dunkirk, and Big Cajun II facilities and intends to convert the coal units at Portland to ultra-low sulfur diesel in 2016. NRG ceased burning coal at Portland in 2014 and plans to cease burning coal at Will County Unit 3 in 2015.

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

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

	Gulf Coast	East - legacy NRG	East - GenOn	East - MWG	Total
	(in millions)				
2015	$81	$2	$51	$215	$349
2016	—	—	6	249	255
2017	—	—	1	—	1
2018	16	1	—	—	17
2019	19	—	—	—	19
Total	$116	$3	$58	$464	$641

NRG's current contracts with the Company's rural electrical customers in the Gulf Coast 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.

2014 Capital Allocation Program

Completed Acquisitions

As described in Item 15 — Note 3, Business Acquisitions and Dispositions, on August 12, 2014, NRG Yield, Inc., through its subsidiary Yield Operating, completed the acquisition of 100% of the membership interests of Alta Wind Asset Management Holdings, LLC, Alta Wind Company, LLC, Alta Wind X Holding Company, LLC, and Alta Wind XI Holding Company, LLC, which collectively owns seven wind facilities that total 947 MWs located in Tehachapi, California and a portfolio of land leases, or the Alta Wind Assets. The purchase price of the Alta Wind Assets was $923 million, as well as working capital adjustments, plus the assumption of $1.6 billion in non-recourse project level debt. Power generated by the Alta Wind facilities is sold to Southern California Edison under long-term power purchase agreements with 21 years of remaining contract life for Alta I-V and 22 years, beginning in 2016, for Alta X and XI.

On April 1, 2014, the Company acquired substantially all of the assets of EME as described in Item 15 — Note 3, Business Acquisitions and Dispositions. EME, through its subsidiaries and affiliates, owned, operated, and leased a portfolio of approximately 8,000 MW consisting of wind energy facilities and coal- and gas-fired generating facilities. The Company paid an aggregate purchase price of $3.5 billion, which reflects the negotiated purchase price of $2.6 billion, an increase of $736 million in acquired cash on hand, cash collateral, restricted cash and cash on unconsolidated subsidiary, as well as an increase in the value of the 12,671,977 shares of NRG common stock issued of $51 million. The purchase price was funded through the issuance of 12,671,977 shares of NRG common stock on April 1, 2014, the issuance of $700 million in newly-issued corporate debt, as described in Item 15 — Note 12, Debt and Capital Leases, with the remaining purchase price funded from cash on hand. The Company also assumed non-recourse debt of approximately $1.2 billion.

In connection with the transaction, NRG agreed to certain conditions with the parties to the Powerton and Joliet, or POJO, sale-leaseback transaction subject to which an NRG subsidiary assumed the POJO leveraged leases and NRG guaranteed the remaining payments under each lease.

In addition, the Company also acquired the competitive retail electricity business of Dominion as described in Item 15 — Note 3, Business Acquisitions and Dispositions and Roof Diagnostics Solar, Goal Zero and Pure Energies, as described in Item 1 — Business.

Common Stock Dividends

The following table lists the dividends paid during 2014:

	Fourth Quarter 2014	Third Quarter 2014	Second Quarter 2014	First Quarter 2014
Dividends per Common Share	$0.14	$0.14	$0.14	$0.12

Preferred Stock Dividend Payments

For the year ended December 31, 2014, NRG paid $9 million in dividend payments to holders of the Company's 2.822% Preferred Stock. On December 23, 2014, NRG and the Credit Suisse Group amended and restated its 250,000 shares, reducing the rate from 3.625% to 2.822%. In connection with the refinancing of the 2.822% Preferred Stock, the Company paid $5 million in consent fees, which was accounted for as a dividend payment to the holders, and recorded the balance of its preferred stock at fair value, which resulted in an increase of $42 million to the balance. The increase was recorded as a non-cash dividend on the preferred stock.

Debt Reduction

The following table lists the Senior Notes redemptions in 2014 which were funded with a portion of the proceeds from the 2024 Senior Notes and 2022 Senior Notes borrowings:

Redemption date	Senior Notes	Principal redeemed (in millions)	Average early redemption percentage	
September 3, 2014	8.5% due 2019	$225	104.250	%
May 21, 2014	7.625% due 2019	372	103.813	%
April 21, 2014	8.5% due 2019	74	105.250	%
April 21, 2014	7.625% due 2019	337	104.200	%
February 10, 2014	8.5% due 2019	308	106.992	%
February 10, 2014	7.625% due 2019	91	105.500	%
		$1,407		

2015 Capital Allocation Program

In December 2014, the Company was authorized to repurchase $100 million of its common stock under the 2015 Capital Allocation Program. The purchase of common stock was made using cash on hand. As of December 31, 2014, the Company had purchased 1,624,360 shares of NRG common stock for approximately $44 million at an average cost of $26.95 per share. In the first quarter of 2015, the Company purchased an additional 2,224,830 shares of NRG common stock for approximately $56 million at an average cost of $25.25 per share.

On February 17, 2015, NRG paid a quarterly dividend on the Company's common stock of $0.145 per share, or $0.58 per share on an annualized basis, an increase of 4% from $0.14 per share, or $0.56 per share on an annualized basis. Dividends, share repurchases and debt reduction under the Capital Allocation Program are subject to market prices, financial restrictions under the Company's debt facilities and securities laws.

Fuel Repowerings and Conversions

The table below lists projected repowering and conversion projects at certain NRG Business facilities:

Facility	Net Generation Capacity (MW)	Project Type	Fuel Type	Targeted COD
Avon Lake Units 7 and 9	732	Natural Gas Conversion	Natural Gas	Summer 2016
Big Cajun Unit 2	575	Natural Gas Conversion[a]	Natural Gas	Spring 2015
Dunkirk Units 2, 3 and 4	445	Natural Gas Conversion	Natural Gas	Spring 2016
Encina Units 1, 2, 3, 4, 5 and GT[b]	633	Repowering	Natural Gas	Fall 2017
Joliet Units 6, 7 and 8	1,326	Natural Gas Conversion[a]	Natural Gas	Summer 2016
Mandalay Units 1 and 2[b]	262	Repowering	Natural Gas	Spring 2020
New Castle Units 3, 4 and 5	325	Natural Gas Conversion	Natural Gas	Summer 2016
Portland Units 1 and 2	401	Ultra-Low Sulfur Diesel Conversion	Ultra-Low Sulfur Diesel	Summer 2016
P.H. Robinson Peakers 1-6	330	Repowering	Natural Gas	Spring 2016
Shawville Units 1, 2, 3 and 4	597	Natural Gas Conversion	Natural Gas	Summer 2016
Total Fuel Repowerings and Conversions	5,626			

(a) The Company plans to incur environmental capital expenditures associated with controls to satisfy MATS. These expenditures are included in the Company's environmental capital expenditures estimate noted above.

(b) Projects are subject to applicable regulatory approvals and permits.

Development Project

In ERCOT, NRG Business obtained an air permit in 2014 and delivered notice to proceed for a new peaking facility at the Company's former P.H. Robinson Electric Generating Station in Bacliff, Texas. The Company will acquire the facility upon successful commercial operation. The addition of these peakers will improve the ability of the Company to respond to volatile prices and to meet its peak load, at a cost of approximately $400 per kw.

Cash Flow Discussion

2014 compared to 2013

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

	Year ended December 31,		
(In millions)	2014	2013	Change
Net cash provided by operating activities	$1,510	$1,270	$240
Net cash used by investing activities	(2,903)	(2,528)	(375)
Net cash provided by financing activities	1,265	1,427	(162)

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	$338
Change in cash paid in support of risk management activities	193
Other changes in working capital	(291)
	$240

Net Cash Used By Investing Activities

Changes to net cash used by investing activities were driven by:

Increase in cash paid for acquisitions, primarily related to the EME and Alta Wind acquisitions	$(2,442)
Decrease in capital expenditures due to decreased spending on growth projects	1,078
Increase in proceeds from renewable energy grants	861
Proceeds from the sale of assets	155
Increase in restricted cash	(101)
Proceeds for payment of cash grant bridge loan	57
Other	17
	$(375)

Net Cash Provided By Financing Activities

Changes in net cash provided by financing activities were driven by:

Net increase in borrowings, primarily due to the issuance of the 2022 and 2024 Senior Notes	$2,786
Net increase in debt payments primarily due to the redemption of 2019 Senior Notes and the repayment of the cash grant bridge loans	(2,892)
Decrease in financing element of acquired derivatives	(258)
Cash contributions from noncontrolling interests	288
Increase in cash paid for debt issuance costs	(17)
Increase in payment of dividends	(42)
Contingent consideration payments	(18)
Prior year repurchase of treasury shares, offset by increase in issuance of common shares	(9)
	$(162)

2013 compared to 2012

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	(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, 2014, the Company had domestic pre-tax book income of $126 million and foreign pre-tax book income of $9 million. For the year ended December 31, 2014, the Company generated an NOL of $1.2 billion which is available to offset taxable income in future periods. As of December 31, 2014, the Company has cumulative domestic Federal NOL carryforwards of $4.3 billion which will begin expiring in 2026 and cumulative state NOL carryforwards of $3.3 billion for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $228 million, of which $3 million will expire through 2015 and of which $225 million do not have an expiration date.

In addition to these amounts, the Company has $71 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 2015.

However, as the position remains uncertain for the $71 million of tax effected uncertain tax benefits, the Company has recorded a non-current tax liability of $53 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $53 million non-current tax liability for uncertain tax benefits is from positions taken on various state returns, including accrued interest.

The Company 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 2009.

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 2.822% 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, 2014, 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, 2014, 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 $303 million as of December 31, 2014. 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.

Contractual Cash Obligations	By Remaining Maturity at December 31, 2014					
	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total [(a)]	2013 Total
	(In millions)					
Long-term debt (including estimated interest)	$1,650	$3,988	$6,741	$16,043	$28,422	$23,480
Capital lease obligations (including estimated interest)	5	1	1	1	8	15
Operating leases	338	597	475	1,545	2,955	2,461
Fuel purchase and transportation obligations	1,018	608	387	608	2,621	2,564
Fixed purchased power commitments	34	31	1	—	66	65
Pension minimum funding requirement [(b)]	34	57	94	253	438	430
Other postretirement benefits minimum funding requirement [(c)]	11	25	28	84	148	144
Other liabilities [(d)]	251	130	129	471	981	1,223
Total	$3,341	$5,437	$7,856	$19,005	$35,639	$30,382

(a) Excludes $53 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 $763 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.

Guarantees	By Remaining Maturity at December 31, 2014					
	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2013 Total
	(In millions)					
Letters of credit and surety bonds	$1,631	$283	$—	$—	$1,914	$1,701
Asset sales guarantee obligations	35	—	257	—	292	275
Commercial sales arrangements	115	168	8	1,489	1,780	1,554
Other guarantees	73	15	—	1,086	1,174	551
Total guarantees	$1,854	$466	$265	$2,575	$5,160	$4,081

Fair Value of Derivative Instruments

NRG may enter into 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, 2014, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2014. 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, 2013	$389
Contracts realized or otherwise settled during the period	(313)
Contracts acquired during the period	35
Changes in fair value	302
Fair value of contracts as of December 31, 2014	$413

	Fair Value of Contracts as of December 31, 2014				
	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	$8	$74	$(8)	$—	$74
Level 2	292	6	(19)	(20)	259
Level 3	71	9	(1)	1	80
Total	$371	$89	$(28)	$(19)	$413

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, 2014, NRG's net derivative asset was $413 million, an increase to total fair value of $24 million as compared to December 31, 2013. This increase was primarily driven by an increase in fair value of existing contracts due to the decreases in gas and power prices and contracts acquired during the period, partially offset by the roll off of contracts that settled during the period.

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 $422 million in the net value of derivatives as of December 31, 2014.

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 $402 million in the net value of derivatives as of December 31, 2014.

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 Assumptions used in forecasting borrowings 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, 2014, NRG had a valuation allowance of $265 million. This amount is comprised of foreign net operating loss carryforwards of $64 million, foreign capital loss carryforwards of approximately $1 million and U.S. domestic state NOLs of $200 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 its 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.

The Company 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 2009.

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.

During the fourth quarter of 2014, the Company determined that it would pursue retiring the 636 MW natural-gas fired Coolwater facility, in Dagget, California. The facility faced critical repairs on the cooling towers for Units 3 and 4 and, during the fourth quarter of 2014, did not receive any awards in a near-term capacity auction and no interest in a bilateral capacity deal. 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 assets and as a result, the assets are considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. The Company retired the Coolwater facility effective January 1, 2015. All remaining fixed assets of the station were written off resulting in an impairment loss of $22 million.

During the third quarter of 2014, the Company determined that it will pursue mothballing the 463 MW natural gas-fired Osceola facility, in Saint Cloud, Florida. 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 assets and as a result, the assets are considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. Due to the location of the facility, it was determined that the best indicator of fair value is the market value of the combustion turbines. The Company recorded an impairment loss of approximately $60 million, which represents the excess of the carrying value over the fair market value.

During the third quarter of 2014, the Company recorded an impairment loss of $10 million to reduce the carrying value of certain solar panels to their approximate fair value.

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.

In the fourth quarter of 2013, 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 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 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, 2014, NRG reported goodwill of $2.6 billion, consisting of $1.7 billion associated with the acquisition of Texas Genco in 2006, or NRG Texas, $485 million for its NRG Home businesses, approximately $330 million related to the acquisition of EME and $46 million 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 zero of the goodwill impairment test, performing its qualitative assessment of macroeconomic, industry and market events and circumstances; and the overall financial performance, subsequent to the April 2014, March 2014 and September 2014 acquisition dates, of the NRG Wind LLC (EME wind assets), Dominion and Goal Zero reporting units, respectively. The Company also performed step zero for the NRG Home Solar reporting unit, which is comprised of the goodwill of wholly owned subsidiaries RDS and Pure Energies, acquired in March 2014 and October 2014, respectively. The Company determined it was not more likely than not that the fair value of goodwill attributed to these reporting units was less than its carrying amount; as such, the annual two-step impairment test was deemed not necessary to be performed for all of the reporting units tested with step zero for the year ended December 31, 2014.

The Company performed step one of the two-step impairment test for the reporting units in the following table. 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 the reporting units' invested capital exceeds its carrying value and as such, the Company concluded that goodwill associated with the reporting units in the following table is not impaired as of December 31, 2014:

Reporting Unit	% Fair Value Over Carrying Value
NRG Business	
NRG Curtailment Solutions	138
NRG Home	
Green Mountain	220
Energy Plus	164
NRG Home & Business Solutions (Home warranty and repairs businesses)	107
NRG Renew	
Solar Power Partners	175

The Company also performed step one of the two-step impairment test for its Texas reporting unit, NRG Texas. 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. 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 2020 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 NRG's retail businesses was determined by capitalizing estimated annual collateral charges and supply cost savings.

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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 was 11% below its carrying value as of December 31, 2014. 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 step two was required. 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 step two analysis it was determined that no goodwill impairment was necessary as of December 31, 2014.

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 for its step two analysis 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 29% below its carrying value as of December 31, 2014. The Company then allocated the revised fair value to the individual asset and liabilities using a hypothetical purchase price allocation in order to determine the implied fair value of goodwill. Under the hypothetical step two for the sensitivity scenario it was also determined that the fair value of the implied goodwill exceeded the carrying amount so no goodwill impairment was necessary as of December 31, 2014.

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 2015 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, 2014, the VaR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the VaR model, was $49 million.

The following table summarizes average, maximum and minimum VaR for NRG for the years ended December 31, 2014, and 2013:

(In millions)	2014	2013
VaR as of December 31,	$49	$76
For the year ended December 31,		
Average	$88	$88
Maximum	142	104
Minimum	49	72

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, 2014, for the entire term of these instruments entered into for both asset management and trading, was $57 million, primarily driven by asset-backed transactions.

Interest Rate Risk

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

In 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, 2014, the Company would have owed the counterparties $166 million. Based on the investment grade rating of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of December 31, 2014, a 1% change in interest rates would result in a $23 million change in interest expense on a rolling twelve month basis.

As of December 31, 2014, the Company's debt fair value and carrying value were both $20.4 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 $1.5 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 $406 million as of December 31, 2014 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 $193 million as of December 31, 2014. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2014.

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, 2014, aggregate counterparty credit exposure to a significant portion of the Company's counterparties totaled $963 million, of which the Company held collateral (cash and letters of credit) against those positions of $12 million resulting in a net exposure of $953 million. Approximately 91% of the Company's exposure before collateral is expected to roll off by the end of 2016. 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, NPNS, and non-derivative transactions. As of December 31, 2014, 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	54	%
Utilities, energy merchants, marketers and other	32	
ISOs	14	
Total	100	%

Category	Net Exposure [(a)] (% of Total)	
Investment grade	96	%
Non-Investment grade	1	
Non-Rated	3	
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 $312 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, Gulf Coast 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, 2014, credit exposure to these counterparties was approximately $3.4 billion, including $1.7 billion 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, 2014, the Company's retail customer credit exposure to C&I and Mass customers was diversified across many customers and various industries, as well as government entities. The Company is also subject to risk with respect to its NRG Home Solar customers. The Company's bad debt expense resulting from credit risk was $64 million, $67 million, and $45 million for the years ending December 31, 2014, 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, 2014, was $61 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2014, was $42 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 $30 million as of December 31, 2014.

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, 2014.

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 2014 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.

Management's Report on Internal Control over Financial Reporting

The Company'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 (2013) 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 (2013), the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2014.

The scope of management’s assessment of the effectiveness of its internal control over financial reporting included the Company's consolidated operations except for the operations of the Alta Wind Assets, which NRG Yield, Inc. acquired through its subsidiary Yield Operating in August 2014. The Alta Wind Assets represented 6% of the Company’s consolidated total assets and less than 1% of consolidated operating revenues as of and for the year ended

December 31, 2014.
The effectiveness of the Company's internal control over financial reporting as of December 31, 2014, has been audited by KPMG LLP, the Company's independent registered public accounting firm, as stated in its report which is included in this Form 10 K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited NRG Energy, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). NRG Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, NRG Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The scope of management's assessment of their effectiveness of internal control over financial reporting included NRG Energy, Inc.'s consolidated operations except for the operations of the Alta Wind Assets, which NRG Yield, Inc. acquired through its subsidiary Yield Operating in August 2014. The Alta Wind Assets represented 6% of NRG Energy, Inc.'s consolidated total assets and less than 1% of consolidated operating revenues as of and for the year ended December 31, 2014.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive (loss)/income, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2014, and our report dated February 27, 2015 expressed an unqualified opinion on those consolidated financial statements.

(signed) KPMG LLP

Philadelphia, PA

February 27, 2015

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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 boards of the following public companies: Occidental Petroleum Corporation, PBF Energy and Two Harbors Investment Corp. He also serves on the board of C3 Energy Resource Management, a private company. 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, PetroTiger and Sindicatum Sustainable Resources. 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 serves on the board of Freshpet, Inc. 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 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 founding Chairman of Genesis Park LP, a Houston-based private equity business specializing in technology and communications investments. In that capacity, he served from 2004 - 2011 as the CEO of Alpheus Communications, L.P., a Texas wholesale telecommunications provider, and as Former Chairman of CapRock Services, Inc., the largest provider of satellite services to the global energy business. He serves on the board of one other publicly traded company, Stewart Information Services Corporation (Stewart Title). He is former Chairman of the Houston Branch of the Federal Reserve Bank of Dallas and the Greater Houston Partnership and is current Chairman of the Texas Ethics Commission. Hobby also served as Texas Lieutenant Governor Bullock's Chief of Staff and as an Assistant United States Attorney from 1989 to 1992. He is a graduate of the University of Virginia and the University of Texas School of Law.

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 2011 to 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 January 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 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.

Tanuja Dehne has served as Senior Vice President and Chief Administrative Officer since December 2014. In this capacity, Ms. Dehne is responsible for the oversight of NRG’s Human Resources, Information Technology, Communications and Sustainability Departments, including NRG’s charitable giving program, M&A integrations and big data analytics. Ms. Dehne served as Senior Vice President, Human Resources from November 2011 to January 2014 where she led all areas of Human Resources, including benefits, compensation, labor and employee relations, recruiting and staffing, organizational development and training and human resources information systems for 8,500 employees. From July 2005 to October 2011, Ms. Dehne served as NRG’s Corporate Secretary and was responsible for corporate governance, corporate transactions, including financings, mergers and acquisitions, public and private securities offerings and securities and stock exchange matters and reporting compliance. From 2004 to 2007, Ms. Dehne was NRG’s Assistant General Counsel, Securities and Finance and was promoted to Deputy General Counsel in 2007. Prior to joining NRG, Ms. Dehne was an associate at Saul Ewing LLP, a law firm in Philadelphia, Pennsylvania and Princeton, New Jersey.

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 from February 2009 to August 2012. 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.

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.

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.nrg.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 2015 Annual Meeting of Stockholders.

Item 11 — Executive Compensation

Information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2015 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	6,009,767	(1)	$22.06	7,744,209	
Equity compensation plans not approved by security holders	1,780,198	(2)	40.93	2,150,019	
Total	7,789,965		$30.95	9,894,228	(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 1,560,052 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 1,780,198 at a weighted-average exercise price of $40.93. See Item 15 — Note 20, Stock-Based Compensation, to Consolidated Financial Statements for a discussion of the NRG GenOn LTIP.

(3) Consists of 6,184,157 shares of common stock under NRG's LTIP, 2,150,019 shares of common stock under the NRG GenOn LTIP, and 1,560,052 shares of treasury stock reserved for issuance under the ESPP. In the first quarter of 2015, 124,624 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 2015 Annual Meeting of Stockholders.

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

Information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2015 Annual Meeting of Stockholders.

Item 14 — Principal Accounting Fees and Services

Information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2015 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, 2014, 2013, and 2012
Consolidated Statements of Comprehensive (Loss)/Income — Years ended December 31, 2014, 2013, and 2012
Consolidated Balance Sheets — December 31, 2014 and 2013
Consolidated Statements of Cash Flows — Years ended December 31, 2014, 2013, and 2012
Consolidated Statement of Stockholders' Equity — Years ended December 31, 2014, 2013, and 2012
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 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

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, 2014 and 2013, and the related consolidated statements of operations, comprehensive (loss)/income, cash flows, and stockholders' equity for each of the years in the three year period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, 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, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Our report dated February 27, 2015, on the effectiveness of internal control over financial reporting as of December 31, 2014, contains an explanatory paragraph that states that the scope of management's assessment of their effectiveness of internal control over financial reporting included the NRG Energy, Inc.'s consolidated operations except for the operations of Alta Wind Assets, which NRG Energy, Inc. acquired in August 2014. The Alta Wind Assets represented 6% of NRG Energy, Inc.'s consolidated total assets and less than 1% of consolidated operating revenues as of and for the year ended December 31, 2014. Our audit of internal control over financial reporting of NRG Energy, Inc. also excluded an evaluation of the internal control over financial reporting of the Alta Wind Assets.

(signed) KPMG LLP
Philadelphia, Pennsylvania
February 27, 2015

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
(In millions, except per share amounts)	2014	2013	2012
Operating Revenues			
Total operating revenues	$15,868	$11,295	$8,422
Cost of operations	11,779	8,121	6,140
Depreciation and amortization	1,523	1,256	950
Impairment losses	97	459	—
Selling, general and administrative	1,042	904	807
Acquisition-related transaction and integration costs	84	128	107
Development activity expenses	91	84	68
Total operating costs and expenses	14,616	10,952	8,072
Gain on sale of assets	19	—	—
Operating Income	1,271	343	350
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	38	7	37
Bargain purchase gain related to GenOn acquisition	—	—	296
Impairment losses on investments	—	(99)	(2)
Other income, net	22	13	19
Gain on sale of equity-method investment	18	—	—
Loss on debt extinguishment	(95)	(50)	(51)
Interest expense	(1,119)	(848)	(661)
Total other expense	(1,136)	(977)	(362)
Income/(Loss)Before Income Taxes	135	(634)	(12)
Income tax expense/(benefit)	3	(282)	(327)
Net Income/(Loss)	132	(352)	315
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	34	20
Net Income/(Loss) Attributable to NRG Energy, Inc.	134	(386)	295
Dividends for preferred shares	56	9	9
Income/(Loss) Available for Common Stockholders	$78	$(395)	$286
Earnings/(Loss) Per Share Attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding — basic	334	323	232
Net Income/(Loss) per Weighted Average Common Share — Basic	$0.23	$(1.22)	$1.23
Weighted average number of common shares outstanding — diluted	339	323	234
Net Income/(Loss) per Weighted Average Common Share — Diluted	$0.23	$(1.22)	$1.22
Dividends Per Common Share	$0.54	$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,		
	2014	2013	2012
	(In millions)		
Net Income/(Loss)	$132	$(352)	$315
Other Comprehensive (Loss)/Income, net of tax			
Unrealized (loss)/gain on derivatives, net of income tax benefit of $21, $6, and $94	(45)	8	(163)
Foreign currency translation adjustments, net of income tax benefit of $5, $14, and $1	(8)	(24)	(1)
Reclassification adjustment for translation gain realized upon sale of Schkopau, net of income tax benefit of $0, $0, and $6	—	—	(11)
Available-for-sale securities, net of income tax benefit/(expense) of $2, $(2), and $(1)	(7)	3	3
Defined benefit plan, net of income tax benefit/(expense) of $88, $(100), and $21	(129)	168	(52)
Other comprehensive (loss)/income	(189)	155	(224)
Comprehensive (Loss)/Income	(57)	(197)	91
Less: Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	8	34	20
Comprehensive (Loss)/Income Attributable to NRG Energy, Inc.	(65)	(231)	71
Dividends for preferred shares	56	9	9
Comprehensive (Loss)/Income Available for Common Stockholders	$(121)	$(240)	$62

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2014	2013
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$2,116	$2,254
Funds deposited by counterparties	72	63
Restricted cash	457	268
Accounts receivable — trade, less allowance for doubtful accounts of $23 and $40	1,322	1,214
Inventory	1,247	898
Derivative instruments	2,425	1,328
Cash collateral paid in support of energy risk management activities	187	276
Deferred income taxes	174	258
Renewable energy grant receivable	135	539
Current assets held-for-sale	—	19
Prepayments and other current assets	447	479
Total current assets	8,582	7,596
Property, Plant and Equipment		
In service	29,487	23,649
Under construction	770	2,775
Total property, plant and equipment	30,257	26,424
Less accumulated depreciation	(7,890)	(6,573)
Net property, plant and equipment	22,367	19,851
Other Assets		
Equity investments in affiliates	771	453
Notes receivable, less current portion	72	73
Goodwill	2,574	1,985
Intangible assets, net of accumulated amortization of $1,402 and $1,977	2,567	1,140
Nuclear decommissioning trust fund	585	551
Derivative instruments	480	311
Deferred income taxes	1,406	1,202
Non-current assets held-for-sale	17	—
Other non-current assets	1,244	740
Total other assets	9,716	6,455
Total Assets	$40,665	$33,902

See notes to Consolidated Financial Statements.

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

	As of December 31, 2014	2013
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$474	$1,050
Accounts payable	1,060	1,038
Derivative instruments	2,054	1,055
Cash collateral received in support of energy risk management activities	72	63
Accrued interest expense	252	185
Other accrued expenses	553	480
Other current liabilities	394	333
Total current liabilities	4,859	4,204
Other Liabilities		
Long-term debt and capital leases	19,900	15,767
Nuclear decommissioning reserve	310	294
Nuclear decommissioning trust liability	333	324
Postretirement and other benefit obligations	727	506
Deferred income taxes	21	22
Derivative instruments	438	195
Out-of-market contracts, net of accumulated amortization of $562 and $484	1,244	1,177
Other non-current liabilities	847	695
Total non-current liabilities	23,820	18,980
Total Liabilities	28,679	23,184
2.822% and 3.625%, respectively, convertible perpetual preferred stock; $0.01 par value; 250,000 shares issued and outstanding	291	249
Redeemable noncontrolling interest in subsidiaries	19	2
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 415,506,176 and 401,126,780 shares issued and 336,662,624 and 323,779,252 shares outstanding at December 31, 2014 and 2013	4	4
Additional paid-in capital	8,327	7,840
Retained earnings	3,588	3,695
Less treasury stock, at cost; 78,843,552 and 77,347,528 shares at December 31, 2014 and 2013	(1,983)	(1,942)
Accumulated other comprehensive (loss)/income	(174)	5
Noncontrolling interest	1,914	865
Total Stockholders' Equity	11,676	10,467
Total Liabilities and Stockholders' Equity	$40,665	$33,902

See notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Cash Flows from Operating Activities			
Net income/(loss)	$132	$(352)	$315
Adjustments to reconcile net income/(loss) to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	49	84	2
Bargain purchase gain related to GenOn acquisition	—	—	(296)
Depreciation and amortization	1,523	1,256	950
Provision for bad debts	64	67	45
Amortization of nuclear fuel	46	36	39
Amortization of financing costs and debt discount/premiums	(12)	(33)	31
Adjustment to loss on debt extinguishment	25	(15)	9
Amortization of intangibles and out-of-market contracts	64	49	146
Amortization of unearned equity compensation	42	38	41
(Gain)/loss on disposals and sales of assets, net	(4)	(3)	11
Impairment losses	97	558	—
Changes in derivative instruments	(61)	164	124
Changes in deferred income taxes and liability for uncertain tax benefits	(154)	(67)	(353)
Changes in nuclear decommissioning trust liability	19	15	37
Cash (used)/provided by changes in other working capital, net of acquisition and disposition effects:			
Accounts receivable - trade	(2)	(224)	(131)
Inventory	(245)	11	(172)
Prepayments and other current assets	182	(22)	(26)
Accounts payable	(12)	275	(132)
Accrued expenses and other current liabilities	(26)	(114)	231
Other assets and liabilities	(217)	(453)	278
Net Cash Provided by Operating Activities	1,510	1,270	1,149
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(2,936)	(494)	(81)
Cash acquired in GenOn acquisition	—	—	983
Capital expenditures	(909)	(1,987)	(3,396)
Decrease/(increase) in restricted cash, net	57	(22)	(66)
(Increase)/decrease in restricted cash to support equity requirements for U.S. DOE funded projects	(206)	(26)	164
Decrease/(increase) in notes receivable	25	(11)	(24)
Proceeds from renewable energy grants	916	55	62
Purchases of emission allowances, net of proceeds	(16)	5	(1)
Investments in nuclear decommissioning trust fund securities	(619)	(514)	(436)
Proceeds from sales of nuclear decommissioning trust fund securities	600	488	399
Proceeds from sale of assets, net	203	13	137
Investments in unconsolidated affiliates	(103)	—	(25)
Other	85	(35)	22
Net Cash Used by Investing Activities	(2,903)	(2,528)	(2,262)

Cash Flows from Financing Activities			
Payment of dividends to preferred and common stockholders	(196)	(154)	(50)
Net receipts/(payments for) from settlement of acquired derivatives that include financing elements	9	267	(68)
Payment for treasury stock	(39)	(25)	—
Sales proceeds and other contributions from noncontrolling interests in subsidiaries	819	531	347
Proceeds from issuance of common stock	21	16	—
Proceeds from issuance of long-term debt	4,563	1,777	3,165
Payment of debt issuance and hedging costs	(67)	(50)	(35)
Payments for short and long-term debt	(3,827)	(935)	(1,260)
Other	(18)	—	—
Net Cash Provided by Financing Activities	1,265	1,427	2,099
Effect of exchange rate changes on cash and cash equivalents	(10)	(2)	(4)
Net (Decrease)/Increase in Cash and Cash Equivalents	(138)	167	982
Cash and Cash Equivalents at Beginning of Period	2,254	2,087	1,105
Cash and Cash Equivalents at End of Period	$2,116	$2,254	$2,087

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, 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
Impact of NRG Yield, Inc. public offering			217				240	457
Sales proceeds and other contributions from noncontrolling interests							73	73
Balances at December 31, 2013	$—	$ 4	$ 7,840	$ 3,695	$ (1,942)	$ 5	$ 865	$ 10,467
Net income				134			17	151
Other comprehensive loss						(179)		(179)
Issuance of shares for acquisition of EME			401					401
Acquisition of EME noncontrolling interests							352	352
Distributions to noncontrolling interests							(57)	(57)
Equity-based compensation			45					45
Purchase of treasury stock					(44)			(44)
Preferred stock dividends				(9)				(9)
Common stock dividends				(181)				(181)
ESPP share purchases				(4)	3			(1)
Sale of assets to NRG Yield, Inc.			41				(41)	—
				(47)				(47)

Dividend for refinancing of preferred stock								
Equity component of NRG Yield, Inc. convertible notes							23	23
Impact of NRG Yield, Inc. public offering							630	630
Sales proceeds and other contributions from noncontrolling interests							125	125
Balances at December 31, 2014	$—	$ 4	$ 8,327	$ 3,588	$ (1,983)	$ (174)	$ 1,914	$ 11,676

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 company that produces, sells and delivers energy and energy services in major competitive power markets in the U.S. while positioning itself as a leader in the way residential, industrial and commercial consumers think about and use energy products and services. As one of the largest power generators in the U.S., the Company owns and operates approximately 52,000 MWs of generation; engages in the trading of wholesale energy, capacity and related products; transacts in and trades fuel and transportation services; and directly sells energy, services, and innovative, sustainable products and services to retail customers under the name “NRG” and various other retail brand names owned by NRG.
The following table summarizes NRG's global generation portfolio as of December 31, 2014:

	Global Generation Portfolio[(a)] (In MW) NRG Business								
Generation Type	Gulf Coast	East	West	NRG Home Solar	NRG Renew	NRG Yield [(b)]	Total Domestic	Other (Inter-national)	Total Global
Natural gas	8,547	7,744	7,617	—	—	1,393	25,301	144	25,445
Coal	5,689	11,045	—	—	—	—	16,734	605	17,339
Oil	—	5,818	—	—	—	190	6,008	—	6,008
Nuclear	1,176	—	—	—	—	—	1,176	—	1,176
Wind	—	—	—	—	1,964	1,048	3,012	—	3,012
Utility Scale Solar	—	—	—	—	807	343	1,150	—	1,150
Distributed Solar	—	—	—	50	37	10	97	—	97
Total generation capacity	15,412	24,607	7,617	50	2,808	2,984	53,478	749	54,227
Capacity attributable to noncontrolling interest	—	—	—	—	(630)	(1,334)	(1,964)	—	(1,964)
Total net generation capacity	15,412	24,607	7,617	50	2,178	1,650	51,514	749	52,263

(a) Includes 95 active fossil fuel and nuclear plants, 14 Utility Scale Solar facilities, 35 wind farms and multiple Distributed Solar facilities. 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.
(b) 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, which are part of the NRG Yield operating segment, provide steam and chilled water capacity of approximately 1,444MWt through the district energy business, 134MWt of which is available under right-to-use provisions contained in agreements between two of NRG's thermal facilities and certain of their customers.
NRG Business consists of the Company’s wholesale operations, commercial operations, EPC operations, energy services and other critical related functions. NRG has traditionally referred to this business as its wholesale power generation business. In addition to the traditional functions from NRG’s wholesale power generation business, NRG Business also includes NRG’s B2B solutions, which include demand response, commodity sales, energy efficiency and energy management services, and NRG’s conventional distributed generation business, consisting of reliability, combined heat and power, thermal and district heating and cooling and large-scale distributed generation.
NRG Home is a consumer facing business that includes the Company’s residential retail business and NRG’s residential solar business. Products and services range from retail energy, rooftop solar, portable solar and battery products home services, and a variety of bundled products which combine energy with protection products, energy efficiency and

renewable energy solutions. As of December 31, 2014, NRG's retail businesses within NRG Home and NRG Business served approximately 2.8 million Recurring customers, approximately 299,000 Discrete customers and approximately 13,000 rooftop solar customers.

NRG Renew operates the Company’s existing renewables business, including operation of the NRG Yield renewable assets. NRG Renew is also one of the largest solar and wind power developers and owner-operators in the U.S., having developed, constructed and financed a full range of solutions for utilities, schools, municipalities and commercial market segments. In 2014, NRG Renew became one of the top five domestic wind-operators and developers when the Company acquired the wind assets from EME and Alta Wind, as further described in Note 3, Business Acquisitions and Dispositions.

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.nrg.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 consolidates the entity for financial reporting purposes. At the initial public offering, 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.

On July 29, 2014, NRG Yield, Inc. issued an additional 12,075,000 shares of Class A common stock for net proceeds, after underwriting discounts and expenses, of $630 million. NRG Yield, Inc. utilized the proceeds of the offering to acquire 12,075,000 additional Class A units of NRG Yield LLC. As a result, the Company retained a 55.3% interest in NRG Yield LLC increasing the public shareholders interest in NRG Yield LLC to 44.7%. The Company continues to consolidate NRG Yield, Inc. and presents the public ownership of NRG Yield, Inc. as noncontrolling interest. The following table represents the structure of NRG Yield, Inc. as of December 31, 2014:

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 in December 2014, 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 segregated as follows: NRG Business, which includes conventional power generation, the carbon capture business and energy services; NRG Home, which includes NRG Home Retail consisting of residential retail services and products, and NRG Home Solar, which includes the installation and leasing of residential solar services; NRG Renew, which includes solar and wind assets, excluding those in the NRG Yield and NRG Home Solar segments; NRG Yield and corporate activities. NRG Yield includes certain of the Company's contracted generation assets. The Company's corporate segment includes international business and electric vehicle services.

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. The Company removes these inventories when they are used for repairs, maintenance or capital projects. The Company expects to recover the fuel oil, coal, raw materials, and spare parts costs in the ordinary course of business. Sales of inventory are classified as an operating activity in the consolidated statements of cash flows. Finished goods inventory is valued at the lower of cost or net realizable value with cost being determined on a first-in first-out basis. The Company removes these inventories as they are sold to customers.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, in the case of business acquisitions, fair value; however impairment adjustments are recorded whenever events or changes in circumstances indicate that their carrying values may not be recoverable. See Note 3, Business Acquisitions and Dispositions, for more information on acquired property, plant and equipment. 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

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, 2014, 2013, and 2012. 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. During 2014, the Company no longer classifies costs associated with residential solar or carbon capture as development activity expenses.

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, 2014, 2013, and 2012, was $29 million, $64 million, and $104 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, power purchase agreements, 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, 2014.

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.

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 the implied fair value, an impairment charge is recognized for the 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 its 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 $387 million, $166 million and $151 million for the years ended December 31, 2014, 2013, and 2012, 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 $341 million, $356 million and $338 million as of December 31, 2014, 2013, and 2012, respectively, for retail energy sales and services.

Lessor Accounting

Certain of the Company's revenues are obtained through PPAs or other contractual agreements. It was determined that certain of these PPAs qualify as operating leases for which the Company is the operating lessor and are accounted for in accordance with ASC 840, Leases. In order to determine lease classification as operating, the Company evaluates the terms of the PPA to determine if the lease includes any of the following provisions which would indicate capital lease treatment:

- Transfers the ownership of the generating facility,
- Bargain purchase option at the end of the term of the lease,
- Lease term is greater than 75% of the economic life of the generating facility, or
- Present value of minimum lease payments exceed 90% of the fair value of the generating facility at inception of the lease.

In considering the above it was determined that many of the Company's PPAs are operating leases. ASC 840 requires the 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. Certain of these leases have no minimum lease payments and all of the rent is recorded as contingent rent on an actual basis when the electricity is delivered. Judgment is required by management in determining the economic life of each generating facility, in evaluating whether certain lease provisions constitute minimum payments or represent contingent rent and other factors in determining whether a contract contains a lease and whether the lease is an operating lease or capital lease. Contingent rental income recognized in the years ended December 31, 2014, 2013, and 2012 was $544 million, $260 million, and $130 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, 2014, 2013, and 2012, NRG's revenues and cost of operations included gross receipts taxes of $108 million, $88 million, and $79 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 included in cost of operations and is based on estimated supply volumes for the applicable reporting period. A portion of the cost of energy ($86 million, $90 million and $97 million as of December 31, 2014, 2013, and 2012, 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 purchase or 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 a 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. In this case, the gain or loss previously deferred in accumulated OCI would be frozen until the underlying hedged instrument is delivered unless the transactions being hedged is no longer probably of occurring in which case the amount in 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, 2014, 2013, and 2012, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2014, 2013, and 2012 were $1 million, $15 million and $53 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 payable, 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 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.

Tax Equity Arrangements

NRG’s redeemable noncontrolling interest in subsidiaries represents third-party interests in the net assets under certain tax equity arrangements, which are consolidated by the Company, that have been entered into to finance the cost of solar energy systems under operating leases and wind facilities eligible for certain tax credits. The Company has determined that the provisions in the contractual agreements of these structures represent substantive profit sharing arrangements. Further, the Company has determined that the appropriate methodology for calculating the noncontrolling interest and redeemable noncontrolling interest that reflects the substantive profit sharing arrangements is a balance sheet approach utilizing the hypothetical liquidation book value, or HLBV, method. Under the HLBV method, the amounts reported as noncontrolling interests and redeemable noncontrolling interests represent the amounts the investors that are party to the tax equity arrangements would hypothetically receive at each balance sheet date under the liquidation provisions of the contractual agreements, assuming the net assets of the funding structures were liquidated at their recorded amounts determined in accordance with GAAP. The investors’ interests in the results of operations of the funding structures are determined as the difference in noncontrolling interests and redeemable noncontrolling interests at the start and end of each reporting period, after taking into account any capital transactions between the structures and the funds’ investors. The calculations utilized to apply the HLBV method include estimated calculations of taxable income or losses for each reporting period.

To the extent that the third-party has the right to redeem their interests for cash or other assets, NRG has included the noncontrolling interest attributable to the third party as a component of temporary equity in the mezzanine section of the consolidated balance sheet. During 2014, the Company recorded losses attributable to redeemable noncontrolling interests of $19 million under the HLBV method of accounting and had contributions from partners of $36 million.

Sale Leaseback Arrangements

NRG is party to sale-leaseback arrangements that provide for the sale of certain assets to a third party and simultaneous leaseback to the Company. In accordance with ASC 840-40, Sale-Leaseback Transactions, if the seller-lessee retains, through the leaseback, substantially all of the benefits and risks incident to the ownership of the property sold, the sale-leaseback transaction is accounted for as a financing arrangement. An example of this type of continuing involvement would include an option to repurchase the assets or the buyer-lessor having the option to sell the assets back to the Company. This provision is included in most of the Company's sale-leaseback arrangements. As such, the Company accounts for these arrangements as financings.

Under the financing method, the Company does not recognize as income any of the sale proceeds received from the lessor that contractually constitutes payment to acquire the assets subject to these arrangements. Instead, the sale proceeds received are accounted for as financing obligations and leaseback payments made by the Company are allocated between interest expense and a reduction to the financing obligation. Interest on the financing obligation is calculated using the Company's incremental borrowing rate at the inception of the arrangement on the outstanding financing obligation. Judgment is required to determine the appropriate borrowing rate for the arrangement and in determining any gain or loss on the transaction that would be recorded either at the end of or over the lease term.

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, 2014, 2013, and 2012 were $208 million, $195 million, and $197 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. Certain prior year depreciation amounts have been recast to revise provisional purchase accounting estimates for the GenOn acquisition.

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 2014-16 — In November 2014, the FASB issued ASU No. 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity, or ASU No. 2014-16. The amendments of ASU No. 2014-16 clarify how U.S. GAAP should be applied in determining whether the nature of a host contract is more akin to debt or equity and in evaluating whether the economic characteristics and risks of an embedded feature are "clearly and closely related" to its host contract. The guidance in ASU No. 2014-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The Company is currently evaluating the impact of the standard on the Company's results of operations, cash flows and financial position.

ASU 2014-09 — In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), or ASU No. 2014-09. The amendments of ASU No. 2014-09 complete the joint effort between the FASB and the International Accounting Standards Board, IASB, to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards, or IFRS, and to improve financial reporting. The guidance in ASU No. 2014-09 provides that an entity should recognize revenue to depict the transfer of goods or services provided and establishes the following steps to be applied by an entity: (1) identify the contract with a customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies the performance obligation. The guidance of ASU No. 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Company is currently evaluating the impact of the standard on the Company's results of operations, cash flows and financial position.

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 No. 2013-11, which were adopted on January 1, 2014, require 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 adoption of this standard did not impact the Company's results of operations or cash flows.

Note 3 — Business Acquisitions and Dispositions

The Company has completed the following business acquisitions and dispositions that are material to the Company's financial statements:

2015 Dispositions

Sales of Assets to NRG Yield, Inc.

On January 2, 2015, the Company sold the following facilities to NRG Yield, Inc.: Walnut Creek, the Tapestry projects (Buffalo Bear, Pinnacle and Taloga) and Laredo Ridge. NRG Yield, Inc. paid total expected cash consideration of $489 million plus assumed project level debt of $737 million, including $9 million of working capital adjustments. The sale was recorded as a transfer of entities under common control and the related assets were transferred at carrying value.

2014 Acquisitions and Dispositions

Sale of Sabine

On December 2, 2014, the Company, through its subsidiaries GenOn Sabine (Delaware), Inc. and GenOn Sabine (Texas), Inc., completed the sale of its 50% interest in Sabine Cogen, L.P., or Sabine, to Bayou Power, LLC, an affiliate of Rockland Capital, LLC. Sabine owns a 105 MW natural gas-fired cogeneration facility located in Texas. The Company received cash consideration of $35 million at closing. A gain of $18 million was recognized as a result of the transaction and recorded as a gain on sale of equity-method investments within the Company's consolidated statements of operations.

Sales of Assets to NRG Yield, Inc.

On June 30, 2014, the Company sold the following facilities to NRG Yield, Inc.: High Desert, Kansas South, and El Segundo Energy Center. NRG Yield, Inc. paid total cash consideration of $357 million, which represents a base purchase price of $349 million and $8 million of working capital adjustments, plus assumed project level debt of approximately $612 million. The sale was recorded as a transfer of entities under common control and the related assets were transferred at carrying value.

Acquisition of Alta Wind

On August 12, 2014, NRG Yield, Inc., through its subsidiary Yield Operating, completed the acquisition of 100% of the membership interests of Alta Wind Asset Management Holdings, LLC, Alta Wind Company, LLC, Alta Wind X Holding Company, LLC, and Alta Wind XI Holding Company, LLC, which collectively own seven wind facilities that total 947 MWs located in Tehachapi, California and a portfolio of land leases, or the Alta Wind Assets. Power generated by the Alta Wind facility is sold to Southern California Edison under long-term power purchase agreements with 21 years of remaining contract life for Alta I-V and 22 years, beginning in 2016, for Alta X and XI.

The purchase price of the Alta Wind Assets was $923 million, which was comprised of purchase price of $870 million and $53 million paid for working capital balances. In order to fund the purchase price of the acquisition, NRG Yield, Inc. issued 12,075,000 shares of its Class A common stock on July 29, 2014 for net proceeds of $630 million. In addition, on August 5, 2014, Yield Operating issued $500 million in aggregate principal amount at par of 5.375% senior notes due August 2024. Interest on the notes is payable semi-annually on February 15 and August 15 of each year, and commenced on February 15, 2015. The notes are senior unsecured obligations of Yield Operating and are guaranteed by NRG Yield LLC, Yield Operating's parent company, and by certain of Yield Operating's wholly owned subsidiaries.

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 initial accounting for the business combination is not complete because the evaluation necessary to assess the fair values of certain net assets acquired is 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 allocation of the purchase price may be modified up to one year from the date of the acquisition as more information is obtained about the fair value of assets acquired and liabilities assumed. The purchase price of $923 million was provisionally allocated as follows:

	Acquisition Date	Measurement period adjustments	Revised Acquisition Date
	(In millions)		
Assets			
Cash	$22	—	$22
Current and non-current assets	49	—	49
Property, plant and equipment	1,057	247	1,304
Intangible assets	1,420	(243)	1,177
Total assets acquired	2,548	4	2,552
Liabilities			
Debt	1,591	—	1,591
Current and non-current liabilities	34	4	38
Total liabilities assumed	1,625	4	1,629
Net assets acquired	$923	$—	$923

Fair value measurements

The provisional fair values of the property, plant and equipment and 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:

•Property, plant and equipment — The estimated fair values were determined primarily based on an income method using discounted cash flows and validated using a cost approach based on the replacement cost of the assets less economic obsolescence. The income approach was applied by determining the enterprise value for each acquired entity and subtracting the fair value of the intangible assets and working capital to determine the implied value of the tangible fixed assets. This methodology was primarily relied upon as the forecasted cash flows incorporate the specific attributes of each asset including age, useful life, equipment condition and technology. The income approach also allows for an accurate reflection of current and expected market dynamics such as supply and demand and regulatory environment as of the acquisition date.

•Intangible assets - PPAs — The fair values of the PPAs acquired were determined utilizing a variation of the income approach where the incremental future cash flows resulting from the acquired PPAs compared to the cash flows based on current market prices were discounted to present value at the weighted average cost of capital reflective of a market participant. The values were corroborated with available market data. The PPA values will be amortized over a weighted average period of 22 years.
•Intangible assets - Leasehold rights — The fair values of the leasehold rights acquired, which represent the contractual right to receive royalty payments equal to a percentage of PPA revenue from certain projects, were determined utilizing the income approach. The values were corroborated with available market data. The leasehold rights values will be amortized over a period of 21 years, which is equal to the average term of the contracts.

Disposition of 50% Interest in Petra Nova Parish Holdings LLC

On July 3, 2014, the Company, through its wholly owned subsidiary Petra Nova Holdings LLC, sold 50% of its interest in Petra Nova Parish Holdings LLC to JX Nippon Oil Exploration (EOR) Limited, or JX Nippon, a wholly owned subsidiary of JX Nippon Oil & Gas Exploration Corporation. As a result of the sale, the Company no longer has a controlling interest in and has deconsolidated Petra Nova Parish Holdings LLC as of the date of the sale. On July 7, 2014, the Company made its initial capital contribution into the partnership of $35 million, which was funded with the sale proceeds of $76 million. On March 3, 2014, Petra Nova CCS I LLC, a wholly owned subsidiary of Petra Nova Parish Holdings LLC, entered into a fixed-price agreement to build and operate a CCF at the W.A. Parish facility with a consortium of Mitsubishi Heavy Industries America, Inc. and TIC - The Industrial Company. Notice to proceed for the construction on the CCF was issued on July 15, 2014, and commercial operation is expected in late 2016.

Petra Nova Parish Holdings LLC also owns a 75 MW peaking unit at W.A. Parish, which achieved commercial operations on June 26, 2013. The peaking unit will be converted into a cogeneration facility to provide power and steam to the CCF. The CCF is being financed by: (i) up to $167 million from a U.S. DOE CCPI grant of which $7 million has already been received from the grant in the initial design and engineering phase and $48 million has already been received from the grant under the construction phase, (ii) $250 million in loans provided by the Japan Bank for International Cooperation and Mizuho Bank, Ltd., and (iii) approximately $300 million in equity contributions from each of the Company and JX Nippon. The Company’s contribution will include investments already made during the development of the project.

On July 14, 2014, Petra Nova Parish Holdings LLC entered into two credit facilities, or the Petra Nova Parish Credit Agreements, to fund the cost of construction of the CCF at the W.A. Parish facility. The Petra Nova Parish Credit Agreements are comprised of a $75 million Nippon Export and Investment Insurance, or NEXI, covered loan and a $175 million Japan Bank for International Cooperation, or JBIC, facility. The NEXI covered loan has an interest rate of LIBOR plus an applicable margin of 1.75% and the JBIC facility has an interest rate of LIBOR plus an applicable margin of 0.50% during the construction phase which escalates to an applicable margin of 1.50% upon completion of the CCF. Both credit facilities mature in April 2026. NRG has guaranteed its 50% share of the obligations under the Petra Nova Parish Credit Agreements through mechanical completion as defined by the credit agreements.

Acquisition of Dominion's Competitive Electric Retail Business

On March 31, 2014, the Company acquired the competitive retail electricity business of Dominion Resources, Inc., or Dominion. The acquisition of Dominion's competitive retail electricity business increased NRG’s retail portfolio by approximately 540,000 customers in the aggregate by the end of 2014. The acquisition supports NRG's ongoing efforts to expand the Company's retail footprint in the Northeast and to grow its retail position in Texas. The Company paid approximately $192 million as cash consideration for the acquisition, including $165 million of purchase price and $27 million paid for working capital balances, which was funded by cash on hand. The purchase price was provisionally allocated to the following: $40 million to accounts receivable-trade, $62 million to customer relationships, $9 million to trade names, $14 million to current assets, $21 million to derivative assets, $45 million to current and non-current liabilities, and goodwill of $91 million of which $8 million is deductible for U.S. income tax purposes in future periods. The consideration and assets include amounts paid for customer relationships in the Northeast that were accounted for as an asset acquisition. The factors that resulted in goodwill arising from the acquisition include the revenues associated with new customers in new regions and through the synergies associated with combining a new retail business with the Company's generation assets. The acquired assets and liabilities are included within the NRG Home - Retail segment. 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. Any changes to the fair value assessments will affect the value of goodwill. The allocation of the purchase price may be modified up to one year from the date of the acquisition as more information is obtained about the fair value of assets acquired and liabilities assumed. As of December 31, 2014, there were no material measurement period adjustments.

EME Acquisition

On April 1, 2014, the Company acquired substantially all of the assets of EME. EME, through its subsidiaries and affiliates, owned or leased and operated a portfolio of approximately 8,000 MW consisting of wind energy facilities and coal- and gas-fired generating facilities. The Company paid an aggregate purchase price of $3.5 billion, which was comprised of the following:

	Original Purchase Price	Purchase Price on Acquisition Date
Cash and equivalents [(a)]	$2,285	$3,016
Common shares [(b)]	350	401
Liabilities acquired	—	57
Total purchase price	2,635	3,474
Less: cash acquired		1,422
Net purchase price		$2,052

(a) The increase in cash paid relates to an increase in acquired cash on hand as well as changes in cash collateral, restricted cash and cash related to unconsolidated subsidiaries. It also reflects lease and debt payments in 2014.

(b) The increase in the value of the common shares reflects an increase in trading price of NRG common shares between October 18, 2013 and April 1, 2014. The shares of NRG common stock were given a value of $350 million in determining the cash purchase price, which was based upon the volume-weighted average trading price over the 20 trading days prior to October 18, 2013.

The purchase price was funded through the issuance of 12,671,977 shares of NRG common stock on April 1, 2014, the issuance of $700 million in newly-issued corporate debt, as described in Note 12, Debt and Capital Leases, and cash on hand. The Company also assumed non-recourse debt of approximately $1.2 billion.

In connection with the transaction, NRG agreed to certain conditions with the parties to the Powerton and Joliet, or POJO, sale-leaseback transaction subject to which an NRG subsidiary assumed the POJO leveraged leases and NRG guaranteed the remaining payments under each lease, which total $405 million through 2034. 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 comply with environmental regulations, as discussed further in Note 24, Environmental Matters. In addition, NRG assumed certain long-term contractual arrangements for fuel and transportation. Commitments under these arrangements totaled approximately $490 million.

On April 30, 2014, subsequent to the acquisition, the Company acquired the remaining 50% ownership of Mission Del Sol LLC, which owns the Sunrise facility, a 586 MW natural gas facility in Fellows, California, from Chevron Power Holdings Inc. increasing the Company's ownership interest to 100% in exchange for the Company's 50% interest in six cogeneration facilities, previously co-owned with Chevron Power Holdings Inc.

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 initial accounting for the business combination is not complete because the evaluation necessary to assess the fair values of certain net assets acquired is 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 allocation of the purchase price may be modified up to one year from the date of the acquisition as more information is obtained about the fair value of assets acquired and liabilities assumed. The purchase price of $3.5 billion was provisionally allocated as follows:

	Acquisition Date	Measurement period adjustments	Revised Acquisition Date
	(In millions)		
Assets			
Cash	1,422	—	$1,422
Current assets	676	48	724
Property, plant and equipment	2,475	(37)	2,438
Intangible assets	312	(140)	172
Goodwill	—	334	334
Non-current assets	813	(40)	773
Total assets acquired	5,698	165	5,863
Liabilities			
Current and non-current liabilities	533	96	629
Out-of-market contracts and leases	43	116	159
Long-term debt	1,249	—	1,249
Total liabilities assumed	1,825	212	2,037
Less: noncontrolling interest	380	(28)	352
Net assets acquired	$3,493	$(19)	$3,474

The Company incurred and expensed acquisition related transaction costs related to the acquisition of EME of $17 million and integration costs of $38 million for the year ended December 31, 2014.

Fair value measurements

The provisional fair values of the property, plant and equipment, intangible assets and out-of-market contracts 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:

Property, plant and equipment — The estimated fair values were determined primarily based on an income method using discounted cash flows and validated using a market approach based on recent transactions of comparable assets. The income approach was primarily relied upon as the forecasted cash flows more appropriately incorporate differences in regional markets, plant types, age, useful life, equipment condition and environmental controls of each asset. The income approach also allows for a more accurate reflection of current and expected market dynamics such as supply and demand, commodity prices and regulatory environment as of the acquisition date.

Intangible assets — The fair values of the PPAs acquired were determined utilizing a variation of the income approach where the expected future cash flows resulting from the acquired PPAs were reduced by operating costs and charges for contributory assets and then discounted to present value at the weighted average cost of capital of an integrated utility peer group adjusted for project-specific financing attributes. The values were corroborated with available market data. The PPAs will be amortized over an average term of 16 years.

Out-of-market lease contracts — The estimated fair values of the acquired leases were determined utilizing a variation of the income approach under which the fair value of the lease was determined by discounting the future lease payments at an appropriate discount rate and comparing it to the fair value of the property, plant and equipment being leased.

Noncontrolling interest — The estimated fair value of the noncontrolling interests represent the fair value of the partners' contributions as of the acquisition date.

The Company recorded goodwill of $334 million, all of which is deductible for U.S. income tax purposes in future periods. The goodwill primarily represents the Company's ability to further monetize certain of the assets in the portfolio through the sale of assets to NRG Yield, Inc. or to other partners with the ability to further utilize the related tax benefits. The goodwill will be recorded in the NRG Renew segment.

Supplemental Pro Forma Information

Since the acquisition date, EME contributed $1.1 billion in operating revenues and $224 million in net income attributable to NRG. The following supplemental pro forma information represents the results of operations as if NRG had acquired EME on January 1, 2013:

(in millions except per share amounts)	(unaudited) For the year ended December 31, 2014	December 31, 2013
Operating revenues	$16,426	$12,598
Net income/(loss) attributable to NRG Energy, Inc.	143	(1,008)
Earnings/(loss) per share attributable to NRG common stockholders:		
Basic	0.43	(3.00)
Diluted	0.42	(3.00)

The supplemental pro forma information has been adjusted to include the pro-forma impact of depreciation of property, plant and equipment, amortization of lease obligations and out-of-market contracts, based on the preliminary purchase price allocations. The pro forma data has also been adjusted to eliminate non-recurring transaction costs incurred by NRG, as well as the related tax impact. There were no transactions during the periods between NRG and EME. The pro forma results are presented for illustrative purposes only and do not reflect the realization of potential cost savings or any related integration costs. The Company expects to achieve certain cost savings from the acquisition; however, there can be no assurance that these cost savings will be achieved.

2013 Acquisitions

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 accounting for Energy Systems was completed as of September 30, 2014, at which point the provisional fair values became final with no material changes.

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 accounting for the Gregory acquisition was completed as of June 30, 2014, at which point the provisional fair values became final with no material changes.

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.

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,			
	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets				
Notes receivable [a]	$91	$91	$99	$99
Liabilities				
Long-term debt, including current portion	20,366	20,361	16,804	17,222

(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, 2014			
	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	$—	$—	$18	$18
Available-for-sale securities	30	—	—	30
Other [(a)]	21	—	11	32
Nuclear trust fund investments:				
Cash and cash equivalents	14	—	—	14
U.S. government and federal agency obligations	44	3	—	47
Federal agency mortgage-backed securities	—	74	—	74
Commercial mortgage-backed securities	—	25	—	25
Corporate debt securities	—	78	—	78
Equity securities	292	—	52	344
Foreign government fixed income securities	—	3	—	3
Other trust fund investments:				
U.S. government and federal agency obligations	1	—	—	1
Derivative assets:				
Commodity contracts	1,078	1,515	309	2,902
Interest rate contracts	—	2	—	2
Equity contracts	—	—	1	1
Total assets	$1,480	$1,700	$391	$3,571
Derivative liabilities:				
Commodity contracts	$1,004	$1,093	$230	$2,327
Interest rate contracts	—	165	—	165

Total liabilities	$1,004	$1,258	$230	$2,492

(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, 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.

There have been no transfers during the year ended December 31, 2014, between Levels 1 and 2. The following tables reconcile, for the years ended December 31, 2014, and 2013, 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, 2014				
	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, 2014	$16	$10	$56	$ 13	$95
Total gains and losses (realized/unrealized):					
Included in OCI	2	—	—	—	2
Included in earnings	—	1	—	(24)	(23)
Included in nuclear decommissioning obligations	—	—	(5)	—	(5)
Purchases	—	—	2	49	51
Contracts acquired in Dominion and EME acquisitions	—	—	—	39	39
Sales	—	—	(1)	—	(1)
Transfers into Level 3 [(b)]	—	—	—	2	2
Transfers out of Level 3 [(b)]	—	—	—	1	1

Ending balance as of December 31, 2014	$18	$11	$52	$ 80	$161
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, 2014	$—	$—	$—	$ 20	$20

(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, 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
Transfer out of Level 3 [b]	—	—	—	27	27
Ending balance as of December 31, 2013	$16	$10	$56	$ 13	$95
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	$—	$—	$—	$ 1	$1

(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 11% of derivative assets and 9% 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, 2014, the credit reserve resulted in a $2 million increase in fair value which is reflected as a gain in OCI.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2014, 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, 2014, the Company recorded $187 million of cash collateral paid and $72 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, 2014, counterparty credit exposure, excluding credit risk exposure under certain long term agreements, was $963 million and NRG held collateral (cash and letters of credit) against those positions of $12 million, resulting in a net exposure of $953 million. Approximately 91% of the Company's exposure before collateral is expected to roll off by the end of 2016. 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	54	%
Utilities, energy merchants, marketers and other	32	
ISOs	14	
Total	100	%

Category	Net Exposure [(a)] (% of Total)	
Investment grade	96	%
Non-Investment grade	1	
Non-Rated	3	
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 $312 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, Gulf Coast load obligations, wind and 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, 2014, aggregate credit risk exposure managed by NRG to these counterparties was approximately $3.4 billion, including $1.7 billion 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, 2014, the Company's retail customer credit exposure to C&I and Mass customers was diversified across many customers and various industries, as well as government entities. The Company is also subject to risk with respect to its NRG Home Solar customers. The Company's bad debt expense was $64 million, $67 million, and

$45 million for the years ending December 31, 2014, 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 equity contracts.

As the Company engages principally in the trading and marketing of its generation assets and retail businesses, 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 NRG's retail businesses, 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 the Company'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, 2014, 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 2020.
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG's generation assets through 2017.

Also, as of December 31, 2014, 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 2039;
- Coal purchase contract through 2020;
- Power transmission contracts through 2023;
- Natural gas transportation contracts and storage agreements through 2028; and
- Coal transportation contracts through 2029.

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, 2014, NRG had interest rate derivative instruments on non-recourse debt extending through 2032, 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, 2014 and 2013. 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.

		Total Volume	
Commodity	Units	December 31, 2014	December 31, 2013
		(In millions)	
Emissions	Short Ton	2	—
Coal	Short Ton	57	51
Natural Gas	MMBtu	(58)	(166)
Oil	Barrel	1	1
Power	MWh	(56)	(27)
Interest	Dollars	$3,440	$1,444
Equity	Shares	2	—

The decrease in the natural gas position was the result of additional purchases entered into during the year to hedge the Company's 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 the Company's conventional power generation. The increase in the interest rate position was primarily the result of interest rate swaps acquired in connection with the acquisitions of EME and Alta Wind.

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, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$—	$—	$55	$35
Interest rate contracts long-term	2	14	74	29
Commodity contracts current	—	—	—	1
Commodity contracts long-term	—	—	—	1
Total Derivatives Designated as Cash Flow or Fair Value Hedges	2	14	129	66
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	—	—	8	4
Interest rate contracts long-term	—	6	28	1
Commodity contracts current	2,425	1,328	1,991	1,015
Commodity contracts long-term	477	291	336	164
Equity contracts long-term	1	—	—	—
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	2,903	1,625	2,363	1,184
Total Derivatives	$2,905	$1,639	$2,492	$1,250

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, 2014	Gross Amounts of Recognized Assets/Liabilities (in millions)	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
Commodity contracts:				
Derivative assets	$2,902	$(2,155)	$(72)	$675
Derivative liabilities	(2,327)	2,155	27	(145)
Total commodity contracts	575	—	(45)	530
Interest rate contracts:				
Derivative assets	2	(2)	—	—
Derivative liabilities	(165)	2	—	(163)
Total interest rate contracts	(163)	—	—	(163)
Equity contracts:				
Derivative assets	1	—	—	$1
Total derivative instruments	$413	$—	$(45)	$368

	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

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, 2014		
	Energy Commodities (In millions)	Interest Rate	Total
Accumulated OCI balance at December 31, 2013	$(1)	$(22)	$(23)
Reclassified from accumulated OCI to income:			
Due to realization of previously deferred amounts	—	13	13
Mark-to-market of cash flow hedge accounting contracts	—	(58)	(58)
Accumulated OCI balance at December 31, 2014, net of $35 tax	(1)	(67)	(68)
Losses expected to be realized from OCI during the next 12 months, net of $7 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, 2014.

	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)

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	Interest Rate Contracts	Total
	(In millions)		
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)

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,		
	2014	2013	2012
	(In millions)		
Unrealized mark-to-market results			
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$(15)	$(105)	$(247)
Reversal of acquired (gain)/loss positions related to economic hedges	(333)	(357)	20
Net unrealized gains on open positions related to economic hedges	361	177	10
Losses on ineffectiveness associated with open positions treated as cash flow hedges	—	—	(51)
Total unrealized mark-to-market gains/(losses) for economic hedging activities	13	(285)	(268)
Reversal of previously recognized unrealized losses/(gains) on settled positions related to trading activity	1	(50)	(60)
Reversal of acquired gain positions related to trading activity	(32)	—	—
Net unrealized gains on open positions related to trading activity	45	7	46
Total unrealized mark-to-market gains/(losses) for trading activity	14	(43)	(14)
Total unrealized gains/(losses)	$27	$(328)	$(282)

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Unrealized gains/(losses) included in operating revenues	$515	$(621)	$(464)
Unrealized (losses)/gains included in cost of operations	(488)	293	182

Total impact to statement of operations — energy commodities	$27	$(328)	$(282)
Total impact to statement of operations — interest rate contracts	$(31)	$15	$(8)

The reversal of gain or loss positions acquired as part of 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, 2014, the $361 million gain from economic hedge positions was primarily the result of an increase in the value of forward sales of natural gas due to a decrease in natural gas prices.

As of December 31, 2014, NRG had interest rate swaps designated as cash flow hedges on the Dandan solar project. The notional amount on the swaps exceeded the actual debt draws on the project. As such, NRG discontinued the cash flow hedge accounting for these contracts and $6 million of losses previously deferred in OCI was recognized in the statement of operations for the year ended December 31, 2014.

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 losses previously deferred in OCI was recognized in the statement of operations for the year ended December 31, 2013.

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, 2014, was $61 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2014, was $42 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 was approximately $30 million as of December 31, 2014.

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, 2014				As of December 31, 2013			
(In millions, except otherwise noted)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)
Cash and cash equivalents	$14	$ —	$ —	—	$26	$ —	$ —	—
U.S. government and federal agency obligations	47	2	—	11	45	1	1	9
Federal agency mortgage-backed securities	74	2	—	25	62	1	1	24
Commercial mortgage-backed securities	25	—	1	30	14	—	—	29
Corporate debt securities	78	2	1	11	70	1	1	9
Equity securities	344	211	—	—	332	204	—	—
Foreign government fixed income securities	3	1	—	16	2	—	—	9
Total	$585	$ 218	$ 2		$551	$ 207	$ 3	

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,		
	2014	2013	2012
	(In millions)		
Realized gains	$29	$25	$12
Realized losses	8	8	7
Proceeds from sale of securities	600	488	399

Note 7 — Inventory

Inventory consisted of:

	As of December 31,	
	2014	2013
	(In millions)	
Fuel oil	$375	$259
Coal/Lignite	414	290
Natural gas	16	15
Spare parts	424	316
Other	18	18
Total Inventory	$1,247	$898

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,	
	2014	2013
	(In millions)	
Notes receivable — non-affiliates [(a)]	$91	$97
Notes receivable — affiliate		
Avenal Solar Holdings LLC, indefinite maturity date, 4.5% [(b)]	—	2
Total notes receivable	91	99
Less current maturities [(c)]	19	26
Total notes receivable — noncurrent	$72	$73

(a) Primarily relates to Alpine, High Lonesome Mesa, 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
	2014	2013	Lives
	(In millions)		
Facilities and equipment	$27,574	$21,827	1-40 Years
Land and improvements	1,081	1,016	
Nuclear fuel	490	463	5 Years
Office furnishings and equipment	342	343	2-10 Years
Construction in progress	770	2,775	
Total property, plant, and equipment	30,257	26,424	
Accumulated depreciation	(7,890)	(6,573)	
Net property, plant, and equipment	$22,367	$19,851	

Note 10 — Asset Impairments

2014 Impairment Losses

Coolwater — During the fourth quarter of 2014, the Company determined that it would pursue retiring the 636 MW natural-gas fired Coolwater facility in Dagget, California. The facility faced critical repairs on the cooling towers for units 3 and 4 and, during the fourth quarter of 2014, did not receive any awards in a near-term capacity auction and no interest in a bilateral capacity deal. 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 assets and as a result, the assets are considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. The Company retired the Coolwater facility effective January 1, 2015. All remaining fixed assets of the station were written off resulting in an impairment loss of $22 million.

Osceola — During the third quarter of 2014, the Company determined that it will pursue mothballing the 463 MW natural gas-fired Osceola facility, in Saint Cloud, Florida. 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 assets and as a result, the assets are considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. Due to the location of the facility, it was determined that the best indicator of fair value is the market value of the combustion turbines. The Company recorded an impairment loss of approximately $60 million, which represents the excess of the carrying value over the fair market value.

Solar Panels — During the third quarter of 2014, the Company recorded an impairment loss of $10 million to reduce the carrying value of certain solar panels to their approximate fair value.

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.

Note 11 — Goodwill and Other Intangibles

Goodwill — NRG's goodwill balance was $2.6 billion as of December 31, 2014, and $2.0 billion as of December 31, 2013. 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. The Company recorded $334 million of goodwill in connection with the 2014 acquisition of EME. Additionally, in 2014, 2013 and 2012, the Company recorded goodwill for several business acquisitions. The EME acquisition is discussed further in Note 3, Business Acquisitions and Dispositions. As of December 31, 2014, there was no impairment to goodwill. As of December 31, 2014 and 2013, NRG had approximately $831 million and $573 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, 2014, primarily reflect intangible assets established with the acquisitions of various companies in 2014, 2013, 2012, 2011, 2010, 2009, and 2006, and are comprised of the following:

- Emission Allowances — These intangibles primarily consist of SO_2 and NO_x 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.
- 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 Dominion, 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, 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, Energy Plus and Dominion acquisitions, these intangibles are amortized to depreciation and amortization expense, on a straight-line basis.
- Power purchase agreements — Established predominantly with the EME and Alta Wind acquisitions, these represent the fair value of PPAs acquired. These will be amortized, generally on a straight-line basis, over the term of the PPA.
- Other — Consists of renewable energy credits, wind leasehold rights, costs to extend the operating license for STP Units 1 and 2, and the intangible asset related to a purchased ground lease.

The following tables summarize the components of NRG's intangible assets subject to amortization:

Year Ended December 31, 2014	Emission Allowances	Contracts Energy Supply	Contracts Fuel	Contracts Customer	Customer Relationships	Marketing Partnerships	Trade Names	PPA	Other	Total
	(In millions)									
January 1, 2014	$871	$54	$72	$859	$ 743	$ 88	$318	$14	$98	$3,117
Purchases	141	—	—	—	8	—	—	—	33	182
Acquisition of businesses	12	—	—	—	80	—	35	1,252	162	1,541
Usage	—	—	—	—	—	—	—	—	(34)	(34)
Write-off of fully amortized balances	—	—	—	(843)	—	—	—	—	—	(843)
Other	(6)	—	—	—	—	—	—	3	9	6
December 31, 2014	1,018	54	72	16	831	88	353	1,269	268	3,969
Less accumulated amortization[(a)]	(557)	(42)	(63)	(4)	(557)	(27)	(114)	(25)	(13)	(1,402)
Net carrying amount	$461	$12	$9	$12	$ 274	$ 61	$239	$1,244	$255	$2,567

(a) Adjusted for write-off of fully amortized customer contracts of $843 million.

Year Ended December 31, 2013	Emission Allowances	Contracts Energy Supply	Contracts Fuel	Contracts Customer	Customer Relationships	Marketing Partnerships	Trade Names	PPA	Other	Total
	(In millions)									
January 1, 2013	$793	$54	$72	$859	$ 640	$ 88	$318	$4	$88	$2,916
Purchases	76	—	—	—	14	—	—	—	28	118
Acquisition of businesses	—	—	—	—	89	—	—	10	—	99
Usage	—	—	—	—	—	—	—	—	(14)	(14)
Other	2	—	—	—	—	—	—	—	(4)	(2)
December 31, 2013	871	54	72	859	743	88	318	14	98	3,117
Less accumulated amortization	(433)	(36)	(61)	(847)	(487)	(12)	(93)	(1)	(7)	(1,977)
Net carrying amount	$438	$18	$11	$12	$ 256	$ 76	$225	$13	$91	$1,140

The following table presents NRG's amortization of intangible assets for each of the past three years:

Amortization	Years Ended December 31, 2014	2013	2012
	(In millions)		
Emission allowances	$124	$104	$50
Energy supply contracts	6	6	5
Fuel contracts	2	2	2
Customer contracts	—	53	119
Customer relationships	70	72	98
Marketing partnerships	15	8	4

Trade names	21	29	30
Power purchase agreements	24	1	—
Other	6	4	2
Total amortization	$268	$279	$310

The following table presents estimated amortization of NRG's intangible assets for each of the next five years:

Year Ended December 31,	Emission Allowances	Contracts Energy Supply	Fuel	Customer	Customer Relationships	Marketing Partnerships	Trade Names	PPA	Other	Total
2015	$91	$6	$2	$1	$62	$14	$23	$50	$8	$257
2016	94	6	2	1	48	9	23	63	8	254
2017	93	—	1	1	32	5	23	63	8	226
2018	90	—	—	1	20	5	23	63	8	210
2019	88	—	—	1	16	4	23	63	8	203

The following table presents the weighted average remaining amortization period related to NRG's intangible assets purchased in 2014 business acquisitions:

As of December 31, 2014	Trade Names	PPA	Customer Relationships	Other
	(In years)			
Weighted average remaining amortization period	15	21	10	19

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, 2014, the value of emission allowances held-for-sale is $53 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 $159 million and $790 million acquired in the acquisitions of EME and GenOn, respectively, 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 contracts are amortized to revenues.

The following table summarizes the estimated amortization related to NRG's out-of-market contracts:

Year Ended December 31,	Power Contracts	Leases	Gas Transportation	Total
	(In millions)			
2015	$16	47	$37	$100
2016	16	47	42	105
2017	17	47	37	101
2018	17	47	32	96
2019	18	47	29	94

Note 12 — Debt and Capital Leases

Long-term debt and capital leases consisted of the following:

	As of December 31, 2014	2013	Interest Rate % (a)
	(In millions except rates)		
NRG Recourse Debt:			
Senior notes, due 2018	$1,130	$1,130	7.625
Senior notes, due 2019	—	800	7.625
Senior notes, due 2019	—	602	8.500
Senior notes, due 2020	1,063	1,062	8.250
Senior notes, due 2021	1,128	1,128	7.875
Senior notes, due 2022	1,100	—	6.250
Senior notes, due 2023	990	990	6.625
Senior notes, due 2024	1,000	—	6.250
Term loan facility, due 2018	1,983	2,002	L+2.00
Tax-exempt bonds	406	373	4.750 - 6.00
Subtotal NRG Recourse Debt	8,800	8,087	
NRG Non-Recourse Debt:			
GenOn senior notes	2,133	2,183	7.875 - 9.875
GenOn Americas Generation senior notes	929	938	8.500 - 9.125
GenOn-other	60	—	
Subtotal GenOn debt (non-recourse to NRG)	3,122	3,121	
NRG Yield Operating LLC senior notes, due 2024	500	—	5.375
NRG Yield Inc. convertible notes, due 2019	326	—	3.500
NRG West Holdings LLC, term loan, due 2023	506	512	L+2.25 - L+2.875; L+2.25 - L+2.75
NRG Marsh Landing term loan, due 2017 and 2023	464	473	L+1.75 - L+1.875; L+2.75 - L+3.00
Alta Wind I-V lease financing arrangements, due 2034 and 2035	1,036	—	5.696 - 7.015
Alta Wind X, due 2021	300	—	L+2.00
Alta Wind XI, due 2021	191	—	L+2.00
NRG Solar Alpine LLC, due 2014 and 2022	163	221	L+1.75 - L+2.50; L+2.25 -L+2.50
NRG Energy Center Minneapolis LLC, senior secured notes, due 2017, and 2025	121	127	5.95 - 7.25
NRG Yield- other	443	450	various
Subtotal NRG Yield debt (non-recourse to NRG)	4,050	1,783	
Ivanpah Financing, due 2014, 2015, 2033 and 2038	1,187	1,575	0.437 - 4.256; 1.116 - 4.256
Agua Caliente Solar, LLC, due 2037	898	878	2.395 - 3.633
CVSR - High Plains Ranch II LLC, due 2014 and 2037	815	1,104	2.339 - 3.775; 0.611 - 3.579
Walnut Creek, term loans due 2023	391	—	L+1.625

Viento Funding II, Inc., due 2023	196	—	L+2.75
Tapestry Wind LLC, due 2021	192	—	L+1.625
NRG Peaker Finance Co. LLC, bonds, due 2019	100	154	L+1.07
Cedro Hill Wind LLC, due 2025	111	—	L+3.125
NRG - other	504	102	various
Subtotal NRG non-recourse debt	4,394	3,813	
Subtotal non-recourse debt (including GenOn and NRG Yield)	11,566	8,717	
Subtotal long-term debt (including current maturities)	20,366	16,804	
Capital leases:			
Chalk Point capital lease, due 2015	5	10	8.190
Other	3	3	various
Subtotal long-term debt and capital leases (including current maturities)	20,374	16,817	
Less current maturities	474	1,050	
Total long-term debt and capital leases	$19,900	$15,767	

(a) As of December 31, 2014, L+ equals 3 month LIBOR plus x%, with the exception of Viento Funding II term loan which is 6 month LIBOR plus x%.

Long-term debt includes the following premiums/(discounts):

	As of December 31, 2014	2013
	(in millions)	
Senior notes, due 2019	$—	$(5)
Term loan facility, due 2018 [(a)]	(4)	(5)
NRG Peaker Finance Co. LLC, bonds, due 2019 [(b)]	(6)	(11)
NRG Yield Inc. Convertible notes, due 2019	(19)	—
GenOn senior notes, due 2017 [(c)]	41	58
GenOn senior notes, due 2018 [(c)]	83	104
GenOn senior notes, due 2020 [(c)]	60	71
GenOn Americas Generation senior notes, due 2021 [(c)]	46	53
GenOn Americas Generation senior notes, due 2031 [(c)]	33	35
Total premium/(discount)	$234	$300

(a) Discount of $1 million is related to current maturities in 2014 and 2013.

(b) Discounts of $2 million and $4 million are related to current maturities in 2014 and 2013, 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 2024 Senior Notes

On April 21, 2014, NRG issued $1.0 billion in aggregate principal amount at par of 6.25% senior notes due 2024. The notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest is payable semi-annually beginning on November 1, 2014, until the maturity date of May 1, 2024. A portion of the cash proceeds were used to redeem all remaining of its 7.625% 2019 Senior Notes, and the rest of the proceeds were used to redeem all remaining $225 million of its 8.5% 2019 Senior Notes in September 2014, as discussed below.

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 to fund the acquisition of EME.

Redemption of 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.

On April 21, 2014, the Company redeemed $74 million of its 8.5% 2019 Senior Notes and $337 million of its 7.625% 2019 Senior Notes through a tender offer and call, at an average early redemption percentage of 105.250% and 104.200%, respectively. A $22 million loss on debt extinguishment of the 8.5% and 7.625% 2019 Senior Notes was recorded during the three months ended June 30, 2014, primarily consisting of the premiums paid on the redemption and the write-off of previously deferred financing costs.

On May 21, 2014, the Company redeemed for cash all of its remaining 7.625% 2019 Senior Notes at an average early redemption percentage of 103.813%. A $18 million loss on debt extinguishment of the 7.625% 2019 Senior Notes was recorded during the three months ended June 30, 2014, primarily consisting of the premiums paid on the redemption and the write-off of previously deferred financing costs.

On September 3, 2014, the Company redeemed for cash all of its remaining 8.5% 2019 Senior Notes at an average early redemption percentage of 104.25%. A $13 million loss on debt extinguishment of the 8.5% 2019 Senior Notes was recorded during the three months ended September 30, 2014, primarily consisting of the premiums paid on the redemption and the write-off of previously deferred financing costs.

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.

Senior Notes Outstanding

As of December 31, 2014, 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.)8.250% senior notes, issued August 20, 2010 and due September 1, 2020, or the 2020 Senior Notes;
(ii.)7.625% senior notes, issued January 26, 2011 and due January 15, 2018, or the 2018 Senior Notes;
(iii.)7.875% senior notes, issued May 24, 2011 and due May 15, 2021, or the 2021 Senior Notes;
(iv.)6.625% senior notes, issued September 24, 2012 and due March 15, 2023, or the 2023 Senior Notes;
(v.)6.250% senior notes, issued January 27, 2014 and due July 15, 2022, or the 2022 Senior Notes; and
(vi.)6.250% senior notes, issued April 21, 2014 and due May 1, 2024 or the 2024 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.

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%.

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

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	%

2022 Senior Notes

At any time prior to July 15, 2017, NRG may redeem up to 35% of the aggregate principal amount of the 2022 Senior Notes, at a redemption price equal to 106.25% of the principal amount of the notes redeemed, plus accrued and unpaid interest, with an amount equal to the net cash proceeds of certain equity offerings. At any time prior to July 15, 2018, NRG may redeem all or a part of the 2022 Senior Notes, at a redemption price equal to 100% of the principal amount, accrued and unpaid interest to the redemption date, plus a premium. 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 103.125% of the note, plus interest payments due on the note from the date of redemption through July 15, 2018, computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after July 15, 2018, 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	
July 15, 2018 to July 14, 2019	103.125	%
July 15, 2019 to July 14, 2020	101.563	%
July 15, 2020 and thereafter	100.000	%

2024 Senior Notes

At any time prior to May 1, 2017, NRG may redeem up to 35% of the aggregate principal amount of the 2024 Senior Notes, at a redemption price equal to 106.25% of the principal amount of the notes redeemed, plus accrued and unpaid interest, with an amount equal to the net cash proceeds of certain equity offerings. At any time prior to May 1, 2019, NRG may redeem all or a part of the 2024 Senior Notes, at a redemption price equal to 100% of the principal amount, accrued and unpaid interest to the redemption date, plus a premium. 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 103.125% of the note, plus interest payments due on the note from the date of redemption through May 1, 2019 computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after May 1, 2019, 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 1, 2019 to April 30, 2020	103.125	%
May 1, 2020 to April 30, 2021	102.083	%
May 1, 2021 to April 30, 2022	101.042	%
May 1, 2022 and thereafter	100.000	%

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, 2014, a total of $1.1 billion letters of credit were issued under the Revolving Credit Facility, with $1.4 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 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, 2014, 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, 2014, were $36 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, 2014. 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, 2014, NRG had net assets of $5.2 billion that were deemed restricted for purposes of Rule 4-08(e)(3)(ii) 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 GenOn Senior Notes due 2014 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, 2014, GenOn met the consolidated debt ratio component of the restricted payments test. Under the related indentures, 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, 2014, GenOn net assets of $413 million were deemed restricted for purposes of Rule 4-08(e)(3)(ii) 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.

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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 Operating LLC Senior Notes

On August 5, 2014, Yield Operating issued $500 million of senior unsecured notes and utilized the proceeds to fund the acquisition of the Alta Wind Assets. The Yield Operating senior notes bear interest at 5.375% and mature in August 2024. Interest on the notes is payable semi-annually on February 15 and August 15 of each year, and commenced on February 15, 2015. The notes are senior unsecured obligations of Yield Operating and are guaranteed by NRG Yield LLC, Yield Operating’s parent company, and by certain of Yield Operating’s wholly owned current and future subsidiaries.

NRG Yield, Inc. Convertible Notes

In the first quarter of 2014, NRG Yield, Inc. closed on its offering of $345 million aggregate principal amount of 3.50% Convertible Senior Notes due 2019, or the NRG Yield Convertible Notes. The NRG Yield Convertible Notes are convertible, under certain circumstances, into NRG Yield, Inc. Class A 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 Convertible Notes. Interest on the NRG Yield Convertible Notes is payable semi-annually in arrears on February 1 and August 1 of each year, commencing on August 1, 2014. The NRG Yield Convertible Notes 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 Convertible 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. The NRG Yield Convertible Notes are accounted for in accordance with ASC 470-20, Debt with Conversion and Other Options. Under ASC 470-20, issuers of convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are required to separately account for the liability (debt) and equity (conversion option) components. The equity component, the $23 million conversion option value, was recorded to NRG's noncontrolling interest for NRG Yield, Inc. with the offset to debt discount. The debt discount will be amortized to interest expense over the term of the notes. The NRG Yield Convertible Notes are guaranteed by NRG Yield Operating LLC and NRG Yield LLC.

NRG Yield LLC and NRG Yield Operating LLC 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. On April 25, 2014, NRG Yield LLC and Yield Operating amended the revolving credit facility to increase the available line of credit to $450 million and extend its maturity to April 2019. The revolving credit facility can be used for cash or for the issuance of letters of credit. There was no cash drawn and $38 million of letters of credit were issued under the revolving credit facility as of December 31, 2014. On January 2, 2015 NRG Yield Operating LLC borrowed $210 million under its revolving credit agreement to fund the acquisition of Laredo Ridge, Tapestry and Walnut Creek. On February 2, 2015 an optional repayment of $15 million was made.

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that are outstanding as of December 31, 2014.

Acquired EME and Alta Wind Project Financings

The following table summarizes the terms of the significant non-recourse project level debt assumed by the Company in the acquisitions of EME and the Alta Wind Assets:

Amount in millions, except rates	Term Loan Facility			Letter of Credit Facility			Bond/ Note Payable		
Non-Recourse Debt	Amount Outstanding as of December 31, 2014	Interest Rate	Maturity Date	Amount Outstanding as of December 31, 2014	Interest Rate	Maturity Date	Amount Outstanding as of December 31, 2014	Interest Rate	Maturity Date
EME project financings									
Broken Bow Wind	$48	3-mo. LIBOR + 2.875%	12/31/2027	$10	2.875%	12/21/2022	$—	—	—
Cedro Hill Wind	111	3-mo. LIBOR + 3.125%	12/31/2025	10	3.336%	12/22/2017	—	—	—
Crofton Bluffs	25	3-mo. LIBOR + 2.875%	12/31/2027	3	2.875%	12/14/2022	—	—	—
Laredo Ridge Wind[(a)]	108	3-mo. LIBOR + 1.875%	3/31/2026	10	1.875%	12/17/2021	—	—	—
Tapestry Wind[(a)]	192	3-mo. LIBOR + 1.625%	12/21/2021	20	1.625%	12/21/2021	—	—	—
Viento Funding II	196	6-mo. LIBOR + 2.750%	7/11/2023	27	2.750%	7/11/2020	—	—	—
Walnut Creek Energy[(a)]	391	3-mo. LIBOR + 1.625%	5/31/2023	42	1.625%	5/17/2023	—	—	—
WCEP Holding LLC	47	3-mo. LIBOR + 3.000%	5/31/2023	—	—	—	—	—	—
High Lonesome Mesa	—	—	—	7	4.000%	11/1/2017	61	6.850%	11/1/2017
Various	4	various	various	—	various	various	—	—	—
Subtotal EME	1,122			129			61		
Alta Wind project financings									
Alta Realty	—	—	—	—	—	—	34	7.000%	1/31/2031
Alta Wind Asset Management	20	3-mo. LIBOR + 2.375%	5/15/2031	—	—	—	—	—	—

Alta X	300	3-mo. LIBOR + 2.000%	3/31/2020	5	2.000%	3/31/2020	—	—	—
Alta XI	191	3-mo. LIBOR + 2.000%	3/31/2020	—	—	—	—	—	—
Subtotal Alta Wind	511			5			34		
Total	$1,633			$134			$95		

(a) The Company amended certain of the project level debt agreements to reduce interest rates.
All of the assets of Alta X, Alta XI and EME are pledged as collateral under their respective agreements.
Alta Wind Lease financing arrangements
Alta Wind Holdings (Alta Wind II - V) and Alta I have finance lease obligations issued under lease transactions whereby the respective operating entities sold and leased back undivided interests in specific assets of the projects. All of the assets of Alta I-V are pledged as collateral under these arrangements. The sale and related lease transactions are accounted for as financing arrangements as the operating entities have continued involvement with the property.

Amount in millions, except rates	Lease Financing Arrangement			Letter of Credit Facility		
Non-Recourse Debt	Amount Outstanding as of December 31, 2014	Interest Rate	Maturity Date	Amount Outstanding as of December 31, 2014	Interest Rate	Maturity Date
Alta Wind I	$261	7.015%	12/30/2034	$16	3.250%	1/5/2016
Alta Wind II	205	5.696%	12/30/2034	26	2.750%	12/31/2017
Alta Wind III	212	6.067%	12/30/2034	25	2.750%	4/13/2018
Alta Wind IV	138	5.938%	12/30/2034	18	2.750%	5/20/2018
Alta Wind V	220	6.071%	6/30/2035	28	2.750%	6/13/2018
Total	$1,036			$113		

High Lonesome Mesa Facility

Prior to the Company's acquisition of EME, an intercompany tax credit agreement related to the High Lonesome Mesa facility was terminated. The termination resulted in an event of default under the project financing arrangement. As a result, the balance under the project financing arrangement is classified as current and the lender can request repayment at any time. The facility is secured by the assets of High Lonesome Mesa and is non-recourse to NRG.

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 converted 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, 2014, $54 million was outstanding under the term loan, and $5 million in letters of credit in support of the project were issued.

Marsh Landing

On July 17, 2014, Marsh Landing amended its credit agreement to increase its borrowings by $34 million and to reduce the related interest rate for the Tranche A borrowings from LIBOR plus an applicable margin of 2.75% to LIBOR plus 1.75% through December 2017, to LIBOR plus 2.00% through December 2020 and to LIBOR plus 2.25% thereafter; and for the Tranche B to reduce the related interest rate from LIBOR plus 3.00% to LIBOR plus 1.875% through December 2017, to LIBOR plus 2.375% through December 2020 and to LIBOR plus 2.125% thereafter. The proceeds from the borrowings were utilized to make a distribution of $29 million to NRG Yield Operating LLC and to fund the costs of the amendment.

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 that was convertible to a term loan upon completion of the project and a $68 million cash grant loan. On January 15, 2013, the credit agreement was amended reducing the cash grant loan to $63 million. On March 26, 2013, Alpine met the conditions under the credit agreement to convert the construction loan to a term loan. Immediately prior to the conversion, the Company drew an additional $164 million under the construction loan and $62 million under the cash grant loan. The cash grant loan had 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.
In January 2014, Alpine repaid the $62 million of outstanding cash grant loan, including accrued interest and breakage fees, with the proceeds that it had received from the U.S. Treasury Department. On June 24, 2014, Alpine amended the credit agreement to reduce the related interest rate to an interest rate of LIBOR plus an applicable margin of 1.75% through June 30, 2019 and an interest rate of LIBOR plus an applicable margin of 2.00% through November 2022. As of December 31, 2014, $163 million was outstanding under the term loans and $37 million in letters of credit in support of the project were issued.

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 was 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, a revolving facility of $12 million and $22 million of bridge notes. All of the bridge notes were repaid in the second quarter of 2014 with the proceeds of the cash grant. The floating rate notes have an interest rate of 3 month LIBOR. 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, 2014, $55 million of fixed rate notes were outstanding and $8 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.

CVSR Financing

In connection with the acquisition of CVSR on September 30, 2011, 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. 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, 2014, $815 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, 2014, 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 construction loan converted to a term loan on January 28, 2014.

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, 2014, under the West Holdings Credit Agreement, West Holdings borrowed $447 million under the Tranche A Facility, $59 million under the Tranche B Facility, issued a $33 million letter of credit in support of the PPA, issued a $1 million letter of credit under the working capital facility, and issued a $48 million letter of credit under the facility in support of its debt service requirements.

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Agua Caliente Financing

In connection with the acquisition of Agua Caliente on August 5, 2011, 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. 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, 2014, $898 million had been drawn under this agreement.

Ivanpah Financing

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. 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.

In December 2014, the Company received cash grant proceeds from the U.S. Treasury Department of $485 million and utilized the proceeds to repay the cash grant bridge loan outstanding. As of December 31, 2014, the Company had no outstanding cash grant bridge loans due related to the Ivanpah Credit Agreement. The following table reflects the borrowings under the Ivanpah Credit Agreement as of December 31, 2014:

	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, 2033	$392	$380	2.808	%
Solar Partners II, due February 27, 2038	387	377	3.132	%
Solar Partners VIII, due October 27, 2038	440	426	3.097	%
	$1,219	$1,183		

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, 2014, $106 million in principal remained outstanding on these bonds. Upon its 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. In December of 2014 and 2013, NRG contributed an additional $29 million and $32 million, respectively, in equity to Peakers to meet its debt service requirements.

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, swap breakage, 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. On March 3, 2014 Bayou Cove Peaking Power LLC sold Bayou Cove Unit 1, which the

Company continues to manage and operate.

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, 2014.

Non-Recourse Debt	% of Principal		Fixed Interest Rate		Floating Interest Rate	Notional Amount at December 31, 2014 (In millions)	Effective Date	Maturity Date
NRG Peaker Finance Co. LLC	100	%	6.673	%	3-mo. LIBOR + 1.07%	$107	June 18, 2002	June 10, 2019
NRG West Holdings LLC	75	%	2.417	%	3-mo. LIBOR	383	November 30, 2011	August 31, 2023
South Trent Wind LLC	75	%	3.265	%	3-mo. LIBOR	48	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	31	September 30, 2011	December 31, 2029
NRG Solar Alpine LLC	85	%	2.744	%	3-mo. LIBOR	129	various	December 31, 2029
NRG Solar Alpine LLC	85	%	2.421	%	3-mo. LIBOR	10	June 24, 2014	June 30, 2025
NRG Solar Avra Valley LLC	85	%	2.333	%	3-mo. LIBOR	54	November 30, 2012	November 30, 2030
NRG Marsh Landing	75	%	3.244	%	3-mo. LIBOR	431	June 28, 2013	June 30, 2023
Other	75	%	various		various	165	various	various
EME Project Financings								
Broken Bow	90	%	2.960	%	3-mo. LIBOR	43	December 31, 2013	December 21, 2027
Cedro Hill	90	%	4.290	%	3-mo. LIBOR	99	December 31, 2010	December 31, 2025
Crofton Bluffs	90	%	2.748	%	3-mo. LIBOR	22	December 31, 2013	December 21, 2027
Laredo Ridge	90	%	2.310	%	3-mo. LIBOR	86	March 31, 2011	March 31, 2026
Tapestry	90	%	2.210	%	3-mo. LIBOR	172	December 30, 2011	December 21, 2021
Tapestry	50	%	3.570	%	3-mo. LIBOR	60	December 21, 2021	December 21, 2029
Viento Funding II	90	%	various		6-mo. LIBOR	177	various	various
Viento Funding II	90	%	4.985	%	6-mo. LIBOR	65	July 11, 2023	June 30, 2028
Walnut Creek Energy	90	%	various		3-mo. LIBOR	345	June 28, 2013	May 31, 2023
WCEP Holdings	90	%	4.003	%	3-mo. LIBOR	47	June 28, 2013	May 21, 2023
Subtotal EME						1,116		
Alta Wind Project Financings								
Alta X	100	%	various		3-mo. LIBOR	174		

							December 31, 2013	December 31, 2015
Alta X	100	%	various		3-mo. LIBOR	126	December 31, 2013	December 31, 2025
Alta X	100	%	various		3-mo. LIBOR	162	December 31, 2015	December 31, 2020
Alta X	100	%	various		3-mo. LIBOR	103	December 31, 2020	December 31, 2025
Alta XI	100	%	various		3-mo. LIBOR	138	December 31, 2013	December 31, 2015
Alta XI	100	%	various		3-mo. LIBOR	54	December 31, 2013	December 31, 2025
Alta XI	100	%	various		3-mo. LIBOR	103	December 31, 2015	December 31, 2020
Alta XI	100	%	various		3-mo. LIBOR	65	December 31, 2020	December 31, 2025
AWAM	100	%	2.470	%	3-mo. LIBOR	20	May 22, 2013	May 15, 2031
Subtotal Alta Wind						945		
Total						3,440		

Consolidated Annual Maturities

Annual payments based on the maturities of NRG's debt, for the years ending after December 31, 2014, are as follows:

	(In millions)
2015	$473
2016	432
2017	1,209
2018	4,139
2019	765
Thereafter	13,114
Total	$20,132

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, 2014, and 2013, along with the additions, reductions and accretion related to the Company's ARO obligations for the year ended December 31, 2014:

	(In millions)
Balance as of December 31, 2013	$629
Revisions in estimates for current obligations	(8)
Additions	15
Additions for acquisitions	95
Spending for current obligations	(7)
Accretion — Expense	23
Accretion — Nuclear decommissioning	16
Balance as of December 31, 2014	$763

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 $29 million to the Company's pension plans in 2015.

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 decided to terminate/settle the nonqualified legacy GenOn Benefit Restoration Plan and Supplemental Executive Retirement Plan. Final settlement payments totaling $12 million were paid to remaining participants during 2014.

NRG Defined Benefit Plans

The annual net periodic benefit cost/(credit) related to NRG's pension and other postretirement benefit plans include the following components:

	Year Ended December 31,		
	Pension Benefits		
	2014	2013	2012
	(In millions)		
Service cost benefits earned	$30	$30	$14
Interest cost on benefit obligation	53	47	23
Expected return on plan assets	(62)	(55)	(23)
Amortization of unrecognized net (gain)/loss	(6)	9	4
Curtailment	—	(1)	—
Net periodic benefit cost	$15	$30	$18

	Year Ended December 31, Other Postretirement Benefits		
	2014	2013	2012
	(In millions)		
Service cost benefits earned	$3	$4	$2
Interest cost on benefit obligation	9	9	6
Amortization of unrecognized prior service credit	(17)	—	—
Amortization of unrecognized net loss	—	—	1
Net periodic benefit (credit)/cost	$(5)	$13	$9

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	
	2014	2013	2014	2013
	(In millions)			
Benefit obligation at January 1	$1,060	$1,147	$191	$220
Obligations resulting from the EME acquisition	43	—	16	—
Service cost	30	30	3	4
Interest cost	53	47	9	9
Plan amendments	—	5	(18)	(4)
Actuarial (gain)/loss	174	(125)	46	(29)
Employee and retiree contributions	—	—	3	2
Benefit payments	(55)	(43)	(12)	(11)
Curtailment	—	(1)	—	—
Benefit obligation at December 31	1,305	1,060	238	191
Fair value of plan assets at January 1	880	757	—	—
Actual return on plan assets	85	116	—	—
Employee contributions	—	—	3	2
Employer contributions	78	50	9	9
Benefit payments	(55)	(43)	(12)	(11)
Fair value of plan assets at December 31	988	880	—	—
Funded status at December 31 — excess of obligation over assets	$(317)	$(180)	$(238)	$(191)

Amounts recognized in NRG's balance sheets were as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(In millions)			
Current liabilities	$—	$12	$10	$9
Non-current liabilities	317	168	228	182

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	
	2014	2013	2014	2013
	(In millions)			

Net loss/(gain)	$101	$(57)	$34	$(12)
Prior service cost/(credit)	4	4	(7)	(6)

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Other changes in plan assets and benefit obligations recognized in OCI were as follows:

	Year Ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(In millions)			
Net actuarial loss/(gain)	$152	$(188)	$46	$(29)
Amortization of net actuarial loss/(gain)	6	(9)	—	—
Prior service cost/(credit)	—	5	(18)	(4)
Amortization of prior service cost	—	—	17	—
Curtailment	—	1	—	—
Total recognized in other comprehensive loss/(income)	$158	$(191)	$45	$(33)
Total recognized in net periodic pension cost/(credit) and other comprehensive loss/(income)	$173	$(161)	$40	$(20)

The change in net actuarial loss(gain) from 2013 to 2014 primarily reflects the use of an updated mortality table and the change in discount rates described below. The Company's estimated unrecognized loss 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 $2 million. The Company's estimated unrecognized loss and unrecognized prior service credit for NRG's postretirement plan that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is $1 million and $(4) million, respectively.

The following table presents the balances of significant components of NRG's pension plan:

	As of December 31,	
	Pension Benefits	
	2014	2013
	(In millions)	
Projected benefit obligation	$1,305	$1,060
Accumulated benefit obligation	1,172	967
Fair value of plan assets	988	880

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, 2014		
	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	$—	$ 287	$287
Common/collective trust investment — non-U.S. equity	—	149	149
Common/collective trust investment — global equity	—	96	96
Common/collective trust investment — fixed income	—	431	431
Partnerships/joint ventures	—	21	21
Short-term investment fund	4	—	4
Total	$4	$ 984	$988

	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

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 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. Partnerships/joint ventures Level 2 investments consist primarily of a partnership which invests in emerging market equity securities. 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	2014	2013	2014	2013
Discount rate	4.16 %	4.99 %	4.20 %	5.06 %
Rate of compensation increase	3.45 %	3.65 %	N/A	N/A
Health care trend rate	—	—	8.6% grading to 5.0% in 2023	8.5% grading to 5.5% 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	2014	2013	2012	2014	2013	2012
Discount rate	4.99 %	4.16 %	4.95 %	5.06 %	4.31 %	5.15 %
Expected return on plan assets	6.81 %	7.12 %	6.96 %	—	—	—
Rate of compensation increase	3.65 %	3.57 %	4.34 %	—	—	—
Health care trend rate	—	—	—	8.5% grading to 5.5% in 2019	8.3% grading to 5.3% 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 defined benefit retirement plans as of December 31. The discount rate assumptions represent the current rate at which the associated liabilities could be effectively settled at December 31. The Company utilizes the Aon Hewitt AA Above Median, or AA-AM, yield curve to select the appropriate discount rate assumption for each retirement plan. The AA-AM yield curve is a hypothetical AA yield curve represented by a series of annualized individual spot discount rates from 6 months to 99 years. Each bond issue used to build this yield curve must be non-callable, and have an average rating of AA when averaging available Moody's Investor Services, Standard & Poor's and Fitch ratings.

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 assumption 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 year ended December 31, 2014:

U.S. equity	29	%
Non-U.S. equity	19	%
Global equity	10	%
U.S. fixed income	42	%

Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S., non-U.S. and global 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:

		Other Postretirement Benefit	
	Pension Benefit Payments	Benefit Payments	Medicare Prescription Drug Reimbursements
	(In millions)		
2015	$54	$10	$—
2016	59	11	—
2017	61	11	—
2018	66	12	—
2019	72	13	—
2020-2024	424	71	1

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	$2	$(1)
Effect on postretirement benefit obligation	24	(19)

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 each of the years ending December 31, 2014 and 2013, NRG reimbursed STPNOC $14 million towards its defined benefit plans. In 2015, NRG expects to reimburse STPNOC $10.4 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	
	2014	2013	2014	2013
	(In millions)			
Funded status — STPNOC benefit plans	$(71)	$(42)	$(30)	$(52)
Net periodic benefit costs	6	11	3	8
Other changes in plan assets and benefit obligations recognized in other comprehensive income	37	(31)	(29)	(10)

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,		
	2014	2013	2012[(a)]
	(In millions)		
Company contributions to defined contribution plans	$47	$34	$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, 2011 to December 31, 2014, 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, 2011	304,183,720	(76,664,199)	227,519,521
Shares issued under ESPP	—	158,481	158,481
Shares issued from LTIP	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
Shares issued under ESPP	—	128,336	128,336
Shares issued under LTIPs	1,707,419	—	1,707,419
Shares issued in connection with the EME acquisition	12,671,977	—	12,671,977
Share repurchases	—	(1,624,360)	(1,624,360)
Balance as of December 31, 2014	415,506,176	(78,843,552)	336,662,624

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, 2014:

Equity Instrument	Common Stock Reserve Balance
2.822% Convertible perpetual preferred	16,000,000
Long-term incentive plans	19,413,743
Total	35,413,743

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 2014 and 2013, the Company increased its annual common stock dividend by 17% to $0.56 per share and 33% to $0.48 per share, respectively. The following table lists the dividends paid per common share during 2014, 2013 and 2012:

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2014	$0.14	$0.14	$0.14	$0.12
2013	$0.12	$0.12	$0.12	$0.09
2012	$0.09	$0.09	$—	$—

On February 17, 2015, NRG paid a quarterly dividend on the Company's common stock of $0.145 per share, or $0.58 per share on an annualized basis, an increase of 4% from $0.56 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 the lesser of 85% of its fair market value on the offering date or 85% of the fair market value on the exercise date. An offering date occurs each Jan 1 and July1. An exercise date occurs each June 30 and December 31. As of December 31, 2014, there remained 1,560,052 shares of treasury stock reserved for issuance under the ESPP, and in the first quarter of 2015, 124,624 shares of common stock were issued to employee accounts from treasury stock.

2015 Capital Allocation Program — In December 2014, the Company was authorized to repurchase $100 million of its common stock under the 2015 Capital Allocation Program. The purchase of common stock was made using cash on hand. As of December 31, 2014, the Company had purchased 1,624,360 shares of NRG common stock for approximately $44 million at an average cost of $26.95 per share. In the first quarter of 2015, the Company purchased an additional 2,224,830 shares of NRG common stock for approximately $56 million at an average cost of $25.25 per share.

Preferred Stock

2.822% Redeemable Preferred Stock

On December 23, 2014, NRG and the Credit Suisse Group amended and restated its 250,000 shares of 3.625% Convertible Perpetual Preferred Stock, or 3.625% Preferred Stock, which is treated as redeemable preferred stock, initially issued on August 11, 2005 to the Credit Suisse Group in a private placement. The amendment resulted in a reduction of the rate from 3.625% to 2.822% and is hereby referred to as the 2.822% Preferred Stock. The transaction was accounted for as an extinguishment of the 3.625% Preferred Stock and the issuance of new 2.822% Preferred Stock. The loss on extinguishment of the 3.625% Preferred Stock of $42 million represents the increase in redeemable preferred stock as the Company recorded the 2.822% Preferred Stock at a fair value of $291 million in connection with the amendment. The loss on extinguishment of $42 million as well as $5 million in consent fees paid to Credit Suisse, are recorded as a dividend on the preferred shares. This amount reduces net income to arrive at net income/(loss) available to NRG common stockholders in the calculation of earnings per share.

The 2.822% 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 2.822% Preferred Stock has a liquidation preference of $1,378 per share. Holders of the 2.822% Preferred Stock are entitled to receive, out of legally available funds, cash dividends at the rate of 2.822% per annum, or $28.22 per share per year, payable in cash quarterly in arrears commencing on December 30, 2014.

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Each share of the 2.822% Preferred Stock is convertible during the 90-day period beginning December 23, 2019, at the option of NRG or the holder. Holders tendering the 2.822% Preferred Stock for conversion shall be entitled to receive, for each share of 2.822% Preferred Stock converted, $1,378 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 $40.71 and (ii) zero, times (b) 50.7743. 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 $27.14, 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) $27.14 minus the Market Price, times (ii) 50.7743. 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, including, among others, insolvency or a change of control, the holders will have the right to require NRG to repurchase all or a portion of the 2.822% 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 2.822% 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

Entities that are not Consolidated

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, 2014:

Name	Geographic Area	Economic Interest	
Avenal Solar Holdings LLC	United States	50.0	%
Community Wind North, LLC	United States	99.0	%
Elkhorn Ridge Wind, LLC	United States	66.7	%
GenConn Energy LLC	United States	50.0	%
Midway-Sunset Cogeneration Company	United States	50.0	%
Petra Nova Parish Holdings LLC	United States	50.0	%
Saguaro Power Company	United States	50.0	%
San Juan Mesa Wind Project, LLC	United States	75.0	%
Sherbino I Wind Farm LLC	United States	50.0	%
Watson Cogeneration Company	United States	49.0	%
Gladstone Power Station	Australia	37.5	%

	As of December 31,	
	2014	2013
	(In millions)	
Undistributed earnings from equity investments	$76	$94

Petra Nova Parish Holdings LLC — As further described in Note 3, Business Acquisitions and Dispositions, on July 3, 2014, NRG, through its wholly owned subsidiary Petra Nova Holdings LLC, sold 50% of its interest in Petra Nova Parish Holdings LLC to JX Nippon Oil Exploration (EOR) Limited, JX Nippon, a wholly owned subsidiary of JX Nippon Oil & Gas Exploration Corporation. As a result of the sale, the Company no longer has a controlling interest in and has deconsolidated Petra Nova Parish Holdings LLC as of the date of the sale. On July 7, 2014, the Company made its initial capital contribution into the partnership of $35 million, which was funded with the sale proceeds of $76 million. NRG's 50% interest in the partnership is accounted for as an equity method investment. On March 3, 2014, Petra Nova CCS I LLC, a wholly owned subsidiary of Petra Nova Parish Holdings LLC, entered into a fixed-price agreement to build and operate a CCF at the W.A. Parish facility with a consortium of Mitsubishi Heavy Industries America, Inc. and TIC - The Industrial Company. Notice to proceed for the construction on the CCF was issued on July 15, 2014, and commercial operation is expected in late 2016.

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 190 MW 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, 2014, NRG had a $114 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 5-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the 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%. As of December 31, 2014, $228 million was outstanding under the note and nothing was drawn on the working capital facility. The refinancing is secured by all of the GenConn assets.

As discussed in Note 21, Related Party Transactions, NRG earns revenues from an operations and 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, 2014, the outstanding principal balance of the term loan facility was $103 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 $82 million as of December 31, 2014.

Other Equity Investments

Gladstone — Through a joint venture, NRG owns a 37.5% interest in Gladstone, a 1,613 MW 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 $174 million as of December 31, 2014.

Entities that are Consolidated

Capistrano Wind Partners — Through the acquisition of EME, the Company has a controlling financial interest in Capistrano Wind Partners, whose Class B preferred equity interests are held by outside investors which include TIAA Wind Investments LLC, CIRI Energy, LLC and AMP Capital Investors Limited. Capistrano Wind Partners holds 100% ownership in five projects generating 411 MW of wind capacity. The five wind projects include Cedro Hill located in Texas, Mountain Wind Power I, located in Wyoming, Mountain Wind Power II located in Wyoming, Crofton Bluffs located in Nebraska, and Broken Bow I located in Nebraska.

Under the terms of the Capistrano Wind Partners formation documents, the holders of the Class B preferred equity interests receive 100% of the cash available for distribution, up to a scheduled amount to target a certain return and thereafter cash distributions are shared. The Company retains indirect beneficial ownership of the wind projects and retains responsibilities for managing the operations of Capistrano Wind Partners. Accordingly, the Company consolidates these projects. The Company does not consolidate Capistrano Wind Partners for tax purposes.

The summarized financial information for Capistrano Wind Holdings consisted of the following:

(In millions)	December 31, 2014
Current assets	$31
Net property, plant and equipment	586
Other long-term assets	140
Total assets	757
Current liabilities	34

Long-term debt	183
Other long-term liabilities	150
Total liabilities	367
Noncontrolling interests	$356

Note 17 — Earnings/(Loss) Per Share

Basic earnings/(loss) per common share is computed by dividing net income/(loss) 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 earnings/(loss) per share is computed in a manner consistent with that of basic earnings/(loss) 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 earnings/(loss) per share. However, these instruments are included in the denominator for purposes of computing diluted earnings/(loss) 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 2.822% Preferred Stock.

The reconciliation of NRG's basic earnings/(loss) per share to diluted earnings/(loss) per share is shown in the following table:

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except per share amounts)		
Basic earnings/(loss) per share attributable to NRG common stockholders			
Net income/(loss) attributable to NRG Energy, Inc.	$134	$(386)	$295
Dividends for preferred shares	9	9	9
Dividends for refinancing of preferred shares	47	—	—
Income/(Loss) Available to Common Stockholders	$78	$(395)	$286
Weighted average number of common shares outstanding	334	323	232
Earnings/(Loss) per weighted average common share — basic	$0.23	$(1.22)	$1.23
Diluted earnings/(loss) per share attributable to NRG common stockholders			
Weighted average number of common shares outstanding	334	323	232
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	5	—	2
Total dilutive shares	339	323	234
Earnings/(Loss) per weighted average common share — diluted	$0.23	$(1.22)	$1.22

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 earnings/(loss) per share:

	Year Ended December 31,		
	2014	2013	2012
	(In millions of shares)		
Equity compensation	1	9	8
Embedded derivative of 2.822% redeemable perpetual preferred stock	16	16	16
Total	17	25	24

Note 18 — Segment Reporting

Effective in December 2014, 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 segregated as follows: NRG Business, which includes conventional power generation, the carbon capture business and energy services; NRG Home, which includes NRG Home Retail, consisting of residential retail services and products and NRG Home Solar, which includes the installation and leasing of residential solar services; NRG Renew, which includes solar and wind assets, excluding those in the NRG Yield segment; NRG Yield and corporate activities. NRG Yield includes certain of the Company's contracted generation assets. On June 30, 2014, NRG Yield, Inc. acquired three projects from the Company: El Segundo Energy Center, formerly in the Business segment, Kansas South and High Desert, both formerly in the Renew segment. As the transaction was accounted for as a transfer of entities under common control, all historical periods have been recast to reflect this change. The Company's corporate segment includes international business and electric vehicle services. Intersegment sales are accounted for at market.

For the years ended December 31, 2014, 2013, and 2012, there were no customers from whom the Company derived more than 10% of the Company's consolidated revenues.

	For the Year Ended December 31, 2014							
		NRG Home						
	NRG Business	Retail	Solar	NRG Renew[b]	NRG Yield	Corporate	Eliminations [b]	Total
	(in millions)							
Operating revenues[a]	$11,094	$5,506	$12	$ 513	$583	$74	$ (1,914)	$15,868
Operating expenses	8,906	5,242	78	215	222	71	(1,913)	12,821
Depreciation and amortization	982	122	6	246	136	31	—	1,523
Impairment charges	87	—	—	32	—	—	(22)	97
Acquisition-related transaction and integration costs	1	3	—	—	4	76	—	84
Development activity expenses	13	—	—	42	—	36	—	91
Total operating cost and expenses	9,989	5,367	84	535	362	214	(1,935)	14,616
Gain on sale of assets	19	—	—	—	—	—	—	19
Operating income/(loss)	1,124	139	(72)	(22)	221	(140)	21	1,271
Equity in earnings/(losses) of unconsolidated affiliates	23	—	—	(6)	27	3	(9)	38
Other income, net	35	—	—	4	3	78	(98)	22
Gain on sale of equity-method investment	18	—	—	—	—	—	—	18
Loss on debt extinguishment	—	—	—	(1)	—	(94)	—	(95)
Interest expense	(106)	(1)	—	(137)	(166)	(806)	97	(1,119)
Income/(loss) before income taxes	1,094	138	(72)	(162)	85	(959)	11	135
Income tax expense/(benefit)	1	—	—	—	4	(2)	—	3
Net income/(loss)	$1,093	$138	$(72)	$ (162)	$81	$(957)	$ 11	$132
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	$(1)	$—	$(19)	$ 1	$16	$24	$ (23)	$(2)
Net income/(loss) attributable to NRG Energy, Inc.	$1,094	$138	$(53)	$ (163)	$65	$(981)	$ 34	$134

Balance sheet

Equity investments in affiliates	141	—	—	330	227	174	(101)	771
Capital expenditures[(c)]	611	34	113	162	11	53		984
Goodwill	1,746	387	98	343	—	—	—	2,574
Total assets	28,813	6,048	224	7,785	5,752	30,819	(38,776)	40,665
(a) Operating revenues include inter-segment sales and net derivative gains and losses of:	$1,836	$9	$—	$7	$—	$62	$—	$1,914

(b) Includes an impairment loss resulting from the intercompany sale of solar panels at current market rates. The use of these long-lived assets is anticipated to generate sufficient cash flows to recover the historical cost of the assets and accordingly, the impairment loss was eliminated and the assets remain at historical cost in consolidation.

(c) Includes accruals.

	For the Year Ended December 31, 2013							
		NRG Home						
	NRG Business	Retail	Solar	NRG Renew	NRG Yield	Corporate	Eliminations	Total
	(in millions)							
Operating revenues[d]	$8,637	$4,341	$4	$222	$379	$19	$(2,307)	$11,295
Operating expenses	7,205	3,848	—	83	151	45	(2,307)	9,025
Depreciation and amortization	930	141	4	99	61	21	—	1,256
Impairment charges	459	—	—	—	—	—	—	459
Acquisition-related transaction and integration costs	—	—	—	—	—	128	—	128
Development activity expenses	13	—	9	34	—	28	—	84
Total operating cost and expenses	8,607	3,989	13	216	212	222	(2,307)	10,952
Operating income/(loss)	30	352	(9)	6	167	(203)	—	343
Equity in (loss)/earnings of unconsolidated affiliates	(6)	—	—	(6)	22	—	(3)	7
Impairment losses on investments	—	—	—	—	—	(99)	—	(99)
Other income, net	32	—	—	2	3	77	(101)	13
Loss on debt extinguishment	—	—	—	—	—	(50)	—	(50)
Interest expense	(107)	(3)	—	(51)	(52)	(735)	100	(848)
(Loss)/income before income taxes	(51)	349	(9)	(49)	140	(1,010)	(4)	(634)
Income tax expense/(benefit)	—				8	(290)	—	(282)
Net (loss)/income	(51)	349	(9)	(49)	132	(720)	(4)	(352)
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	22	13	14	(15)	34
Net (loss)/income attributable to NRG Energy, Inc.	$(51)	$349	$(9)	$(71)	$119	$(734)	$11	$(386)
Balance sheet								
Equity investments in affiliates	$51	$—	$—	$87	$227	$188	$(100)	$453
Capital expenditures[e]	439	30	—	818	213	76	—	1,576
Goodwill	1,746	227		12				1,985
Total assets	$23,508	$4,620	$22	$6,006	$3,238	$25,444	$(28,936)	$33,902
(d) Operating revenues include inter-segment sales and net derivative gains and losses of:	$2,230	$9	$—	$7	$—	$61	$—	$2,307

(e) Includes accruals.

	For the Year Ended December 31, 2012							
		NRG Home						
	NRG Business[g]	Retail	Solar	NRG Renew	NRG Yield	Corporate[g]	Eliminations	Total
	(in millions)							
Operating revenues[f]	$5,976	$3,872	$3	$122	$175	$102	$(1,828)	$8,422
Operating expenses	5,212	3,293	—	26	120	114	(1,818)	6,947
Depreciation and amortization	700	162	2	48	25	13	—	950
Acquisition-related transaction and integration costs	—	—	—	—	—	107	—	107
Development activity expenses	10	—	10	30	—	18	—	68
Total operating costs and expenses	5,922	3,455	12	104	145	252	(1,818)	8,072
Operating income/(loss)	54	417	(9)	18	30	(150)	(10)	350
Equity in earnings/of unconsolidated affiliates	10	—	—	1	19	7	—	37
Impairment losses on investments	—	—	—	—	—	(2)	—	(2)
Bargain purchase gain related to GenOn acquisition	—	—	—	—	—	296	—	296
Other income, net	6	—	—	—	1	30	(18)	19
Loss on debt extinguishment	—	—	—	—	—	(51)	—	(51)
Interest expense	(40)	(4)		(26)	(28)	(581)	18	(661)
Income/(loss) before income taxes	30	413	(9)	(7)	22	(451)	(10)	(12)
Income tax expense/(benefit)	—	—	—	—	10	(337)	—	(327)
Net income/(loss)	30	413	(9)	(7)	12	(114)	(10)	315
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	20	—	—	—	20
Net income/(loss) attributable to NRG Energy, Inc.	30	413	(9)	(27)	12	(114)	(10)	295
(f) Operating revenues include inter-segment sales and net derivative gains and losses of:	$1,819	$5	$—	$4	$—	$10	$—	$1,838

(g) Includes GenOn results for the period December 15, 2012 to December 31, 2012.

Note 19 — Income Taxes

The income tax provision from continuing operations consisted of the following amounts:

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except percentages)		
Current			
State	$8	$11	$20
Foreign	—	—	13
Total — current	8	11	33
Deferred			
U.S. Federal	(50)	(207)	(326)
State	41	(57)	(24)
Foreign	4	(29)	(10)
Total — deferred	(5)	(293)	(360)
Total income tax expense/(benefit)	$3	$(282)	$(327)
Effective tax rate	2.2%	44.5%	2,725.0%

The following represents the domestic and foreign components of income/(loss) before income tax expense/(benefit):

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
U.S.	$126	$(549)	$(41)
Foreign	9	(85)	29
Total	$135	$(634)	$(12)

A reconciliation of the U.S. federal statutory rate of 35% to NRG's effective rate is as follows:

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except percentages)		
Income/(Loss) Before Income Taxes	$135	$(634)	$(12)
Tax at 35%	47	(222)	(4)
State taxes	9	19	1
Foreign operations	1	5	(24)
Federal and state tax credits, excluding PTCs	(1)	(36)	(158)
Valuation allowance	6	(5)	5
Expiration/utilization of capital losses	—	10	—
Reversal of valuation allowance on expired/utilized capital losses	—	(10)	—
Impact of non-taxable equity earnings	(11)	(14)	(7)
Bargain purchase gain related to GenOn acquisition	—	—	(104)
Net interest accrued on uncertain tax positions	(2)	(3)	2
Production tax credit	(48)	(14)	(14)
Recognition of uncertain tax benefits	(30)	(11)	(13)
Tax expense attributable to consolidated partnerships	4	8	—
Impact of change in effective state tax rate	22	(21)	(12)
Other	6	12	1
Income tax expense/(benefit)	$3	$(282)	$(327)
Effective income tax rate	2.2%	44.5%	2,725.0%

For the year ended December 31, 2014, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the generation of PTCs generated from various wind facilities including assets acquired in the EME transaction, and a benefit resulting from the recognition of uncertain tax benefits, partially offset by state and local income taxes including a change in the effective state rate.

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 PTCs generated from certain Gulf Coast 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 Gulf Coast wind facilities of $14 million.

The temporary differences, which gave rise to the Company's deferred tax assets and liabilities consisted of the following:

	As of December 31,	
	2014	2013
	(In millions)	
Deferred tax liabilities:		
Emissions allowances	$25	$15
Difference between book and tax basis of property	127	22
Derivatives, net	320	334
Goodwill	202	191
Cumulative translation adjustments	8	9
Investment in projects	849	540
Intangibles amortization (excluding goodwill)	99	—
Other	2	—
Total deferred tax liabilities	1,632	1,111
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	266	203
Discount/premium on notes	99	111
Differences between book and tax basis of contracts	531	285
Pension and other postretirement benefits	157	168
Equity compensation	77	57
Bad debt reserve	9	18
U.S. capital loss carryforwards	—	1
U.S. Federal net operating loss carryforwards	1,523	1,381
Foreign net operating loss carryforwards	65	77
State net operating loss carryforwards	302	161
Foreign capital loss carryforwards	1	1
Deferred financing costs	23	3
Federal and state tax credit carryforwards	357	308
Federal benefit on state uncertain tax positions	17	23
Intangibles amortization (excluding goodwill)	—	20
Inventory obsolescence	29	8
Other	—	15
Total deferred tax assets	3,456	2,840
Valuation allowance	(265)	(291)
Total deferred tax assets, net of valuation allowance	3,191	2,549
Net deferred tax asset	$1,559	$1,438

The following table summarizes NRG's net deferred tax position:

	As of December 31,	
	2014	2013
	(In millions)	
Net deferred tax asset — current	$174	$258

Net deferred tax asset — noncurrent	1,406	1,202
Net deferred tax liability — noncurrent	$(21)	$(22)
Net deferred tax asset	$1,559	$1,438

Deferred tax assets and valuation allowance

Net deferred tax balance — As of December 31, 2014, and 2013, NRG recorded a net deferred tax asset of $1.5 billion and $1.4 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 the Company's estimate of future taxable income, the Company considered the profit before tax generated in recent years. Based on the Company's 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 $265 million and $291 million of tax assets as of December 31, 2014 and 2013, respectively, thus a valuation allowance has been recorded. The Company estimates it will need to generate future taxable income of approximately $4.3 billion, to fully realize the net federal deferred tax asset before expiration commencing in 2026.

NOL carryforwards — At December 31, 2014, the Company had tax effected cumulative domestic NOLs consisting of carryforwards for federal income tax purposes of $1.6 billion and state of $302 million. In addition, NRG has cumulative foreign NOL carryforwards of $65 million of which $1 million will expire through 2016 and of which $64 million do not have an expiration date.

Valuation allowance — As of December 31, 2014, the Company's tax effected valuation allowance was $265 million, consisting of $200 million for state deferred tax assets, primarily operating loss carryovers, and $65 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, 2014, NRG recorded a current tax payable of $16 million that represents a tax liability due for domestic state taxes of $14 million, as well as foreign taxes payable of $2 million. NRG has a domestic tax receivable of $174 million, of which $135 million relates to federal cash grants applied for eligible solar energy projects, net of sequestration, the remaining balance of $39 million is primarily related to current tax refunds due from 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 $71 million that if recognized, would impact the Company's income tax expense.

As of December 31, 2014, and 2013, NRG has recorded a non-current tax liability of $53 million and $61 million, respectively.

The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense. During the year ended December 31, 2014, the Company recognized a benefit of $3 million in interest and penalties and accrued interest of $1 million. As of December 31, 2014 and 2013, NRG had cumulative interest and penalties related to these uncertain tax benefits of $5 million and $14 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.

The Company 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 2009.

The following table reconciles the total amounts of uncertain tax benefits:

	As of December 31,	
	2014	2013
	(In millions)	
Balance as of January 1	$115	$193
Increase due to current year positions	—	2
Increase due to prior year positions	10	4
Decrease due to prior year positions	(27)	(40)
Decrease due to settlements and payments	(27)	(44)
Uncertain tax benefits as of December 31	$71	$115

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Note 20 — Stock-Based Compensation
NRG Energy, Inc. Long-Term Incentive Plan
As of December 31, 2014, and 2013, 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 6,184,157 and 7,238,065 shares of common stock remaining available for grants under the NRG LTIP as of December 31, 2014, and 2013, 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, 2014, 5,558,390 shares of NRG common stock were authorized for issuance under the NRG GenOn LTIP, and there were 2,150,019 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 10 years for 2.1 million of NRG's outstanding NQSOs, and six years for the remaining 0.4 million NQSOs. No NQSOs were granted in 2014 or 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, 2013	3,976,981	$35.20	2	$17
Forfeited	(631,116)	43.39		
Exercised	(812,688)	23.35		
Outstanding at December 31, 2014	2,533,177	30.95	2	9
Exercisable at December 31, 2014	2,463,131	31.24	2	8

The following table summarizes the total intrinsic value of options exercised and the cash received from the exercises of options:

	Year Ended December 31,		
	2014	2013	2012
	(In millions, except for weighted average)		
Total intrinsic value of options exercised	$7	$19	$0.3
Cash received from options exercised	21	33	1

Restricted Stock Units

As of December 31, 2014, 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, 2013	2,023,179	$21.22
Granted	1,697,258	29.90
Forfeited	(151,194)	25.03
Vested	(894,617)	21.68
Non-vested at December 31, 2014	2,674,626	26.15

The total fair value of RSUs vested during the years ended December 31, 2014, 2013, and 2012, was $26 million, $22 million and $18 million, respectively. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2014, 2013, and 2012 was $29.90, $23.37, and $17.90, 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, 2013	378,546	$19.78
Granted	51,160	35.63
Converted to Common Stock	(45,043)	24.49
Outstanding at December 31, 2014	384,663	21.21

The aggregate intrinsic values for DSUs outstanding as of December 31, 2014, 2013, and 2012 were approximately $10 million, $7 million, and $15 million respectively. The aggregate intrinsic values for DSUs converted to common stock for the years ended December 31, 2014, 2013, and 2012 were $1.1 million, $12 million and $1.4 million, respectively. The weighted average grant date fair value of DSUs granted during the years ended December 31, 2014, 2013, and 2012 was $35.63, $23.18 and $16.33, 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. For awards prior to 2014, 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.

For 2014 and future awards, 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) three quarters of one share of common stock if the TSR has decreased by no more than 25% 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 75% of the value of the common stock on the date of grant, no common stock will be paid. If the TSR is between 75% 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, 2013	1,836,506	$24.72
Granted	605,144	31.90
Vested	(20,000)	31.22
Forfeited	(117,081)	27.24
Non-vested at December 31, 2014	2,304,569	26.13

The weighted average grant date fair value of MSUs granted during the years ended December 31, 2014, 2013 and 2012, was $31.90, $27.46 and $22.11, 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:

	2014	2013
Expected volatility	23.62%-27.43%	27.12%-29.11%
Expected term (in years)	3-4	3
Risk free rate	0.76%-1.21%	0.37%-0.59%

For the years ended December 31, 2014 and 2013, 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, 2013	314,300	$20.80
Vested	(313,832)	20.78
Forfeited	(468)	20.88
Non-vested at December 31, 2014	—	—

The fair value of PUs was estimated on the date of grant using a Monte Carlo simulation model and expensed over the service period, which equals the vesting period. No PUs were granted after 2011.

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, 2014, for each of the five types of awards issued under the LTIPs. Minimum tax withholdings of $16 million, $13 million, and $6 million for the years ended December 31, 2014, 2013, and 2012, 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.

				Non-vested Compensation Cost	
	Compensation Expense			Unrecognized Total Cost	Weighted Average Recognition Period Remaining (In years)
	Year Ended December 31			As of December 31	
Award	2014	2013	2012	2014	2014
	(In millions, except weighted average data)				
NQSOs	$1	$4	$6	$—	—
RSUs	20	18	21	48	2.5
DSUs	2	2	2	—	—
MSUs	19	14	7	23	1.6
PUs	—	2	4	—	—
Total	$42	$40	$40	$71	
Tax detriment recognized	$(8)	$(6)	$(5)		

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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,		
	2014	2013	2012
	(In millions)		
Revenues from Related Parties Included in Operating Revenues			
Gladstone	$6	$6	$7
GenConn	6	5	6
Total	$12	$11	$13
Interest income from Related Parties Included in Other Income and Expense			
Kraftwerke Schkopau GBR [(a)]	—	—	2
Total	$—	$—	$2

(a) 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. 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 2014, $10 million in 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

Powerton and Joliet Leases

The Company leases 100% interest in the Unit 7 and Unit 8 of the Joliet facility and the Powerton facility through 2030 and 2034, respectively, through its indirect subsidiary, Midwest Generation, 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 EME, the Company recorded the out-of-market value as a liability in out-of-market contracts of $159 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 $14 million per year through the term of the lease.

Future minimum lease commitments under the Powerton and Joliet operating leases for the years ending after December 31, 2014, are as follows:

Period	(In millions)
2015	$67
2016	26
2017	1
2018	1
2019	1
Thereafter	238
Total	$334

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, 2014, are as follows:

Period	(In millions)
2015	$110
2016	150
2017	144
2018	105
2019	139
Thereafter	547
Total	$1,195

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 leases through 2029 in accordance with the terms of the leases. 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.

In late April 2014, NRG notified PJM that it no longer intends to place coal-fired Units 1, 2, 3, and 4 at Shawville generating facility (597 MW) in long term protective layup, but instead will mothball those units beginning on April 16, 2015, and then return those units to service no later than June 1, 2016, using natural gas. 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.

Future minimum lease commitments under the REMA operating leases for the years ending after December 31, 2014, are as follows:

Period	(In millions)
2015	$56
2016	61
2017	63
2018	55
2019	65
Thereafter	334
Total	$634

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 include provisions such as scheduled rent increases, leasehold incentives, and rent concessions over their lease term. 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 $106 million, $88 million, and $67 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2014, are as follows:

Period	(In millions)
2015	$105
2016	87
2017	65
2018	60
2019	49
Thereafter	426
Total [(a)]	$792

(a) Amounts in the table exclude future sublease income of $17 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, 2014, 2013, and 2012, the Company purchased $3.5 billion, $2.8 billion, and $1.4 billion, respectively, under such arrangements.

As of December 31, 2014, the Company's commitments under such outstanding agreements are estimated as follows:

Period	(In millions)
2015	$1,018
2016	327
2017	281
2018	202
2019	185
Thereafter	608

Total	$2,621

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, 2014. Minimum purchase commitment obligations are as follows as of December 31, 2014:

Period	(In millions)
2015	$34
2016	18
2017	13
2018	1
2019	—
Thereafter	—
Total [(a)]	$66

(a) As of December 31, 2014, the maximum remaining term under any individual purchased power contract is five years.

Lignite Contract with Texas Westmoreland Coal Co.

The lignite used to fuel the Gulf Coast 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, 2014, hedges under the first lien were in-the-money for NRG on a counterparty aggregate basis.

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 the co-owners of STP's lost revenue following a property damage event, at a weekly indemnity limit of $2.52 million per unit up to a maximum of $274.4 million nuclear and $183.5 million non-nuclear, and is subject to an eight-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 6 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.

Midwest Generation Asbestos Liabilities

The Company, through its subsidiary, Midwest Generation, may be subject to potential asbestos liabilities as a result of its acquisition of EME. The Company is currently analyzing the scope of potential liability as it may relate to Midwest Generation. The Company believes that it has established an adequate reserve to deal with these cases.

NRG Energy Center San Francisco LLC

In 2013, NRG Energy Center San Francisco LLC received a Notice of Violation from the San Francisco Department of Public Health alleging improper monitoring of three underground storage tanks. The tanks have not leaked. This matter was settled on July 21, 2014, for $123,270.

Louisiana Generating, LLC

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. In February 2014, LaGen and LDEQ settled this matter for approximately $47,000.

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 Mirant's 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 Mirant's 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 Court of Appeals reversed the decision of the District Court. On August 26, 2013, GenOn along with the other defendants in the lawsuit filed a petition for a writ of certiorari to the U.S. Supreme Court challenging the Court of Appeals' decision. On July 1, 2014, the U.S. Supreme Court granted the petition for a writ of certiorari. On January 12, 2015, the U.S. Supreme Court heard oral argument and the case is pending.

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 a writ of certiorari to the U.S. Supreme Court. In June 2013, the U.S. Supreme Court denied the petition for a writ of certiorari, thereby ending one of the five lawsuits. GenOn has agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

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 District 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 Court of Appeals reversed the decision of the District Court. On September 3, 2013, the Company filed a petition for rehearing with the Court of Appeals 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 Court of Appeals decision. On June 2, 2014, the U.S. Supreme Court denied the petition for a writ of certiorari. Following the U.S. Supreme Court's denial of GenOn’s petition for a writ of certiorari, the case continued to be litigated before the U.S. District Court for the Western District of Pennsylvania. After briefing by the parties on

GenOn's motion to strike class allegations in the complaint, the court granted GenOn's motion, but allowed the plaintiffs the opportunity to re-file their complaint. On February 3, 2015, plaintiffs sought leave to file an amended complaint, which the Company is contesting.

Cheswick Monarch Mine NOV

In 2008, the PADEP issued an NOV related to the Monarch mine located near the Cheswick generating facility. It has not been mined for many years. The Company's subsidiary discharged approved wastewaters into the Monarch mine including low-volume wastewater from the Cheswick generating facility and leachate collected from ash disposal facilities. The NOV addresses a permit requirement to pump a minimum water volume from the mine. On September 2, 2014, the Company's subsidiary that owns the Cheswick generating facility, the Commonwealth of Pennsylvania and the PADEP entered into a Consent Order and Agreement resolving the NOV. Pursuant to that Consent Order and Agreement, the Company's subsidiary will, among other things, cease wastewater discharges to the mine, construct a waste treatment facility and contribute $200,000 to the Indianola Mine Trust. The Company's subsidiary is currently planning to incur capital expenditures in connection with wastewater from Cheswick and leachate from ash disposal facilities.

Energy Plus Holdings

In May 2014, Energy Plus Holdings executed a settlement agreement with the Connecticut Office of Attorney General and the Connecticut Office of Consumer Counsel related to its sales, marketing and business practices in Connecticut. The settlement was in accordance with the Company's established reserve for this matter. Energy Plus Holdings continues to cooperate and discuss a resolution of issues with respect to its sales, marketing and business practices in New York with the New York Office of Attorney General.

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 GenOn Mid-Atlantic 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 GenOn Mid-Atlantic a similar letter with respect to the Chalk Point and Dickerson facilities, threatening to sue within 60 days if the facilities were not brought 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 CWA and Maryland environmental laws related to water. The lawsuit is ongoing and seeks injunctive relief and civil penalties in excess of $100,000. The Company does not expect the resolution of this matter to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

Midwest Generation New Source Review Litigation

In August 2009, the EPA and the Illinois Attorney General, or the Government Plaintiffs, filed a complaint, or the Governments' Complaint, in the U.S. District Court for the Northern District of Illinois alleging violations of CAA PSD requirements by Midwest Generation arising from maintenance, repair or replacement projects at six Illinois coal-fired electric generating stations performed by Midwest Generation or Commonwealth Edison, or ComEd, a prior owner of the stations, including alleged failures to obtain PSD construction permits and to comply with BACT requirements. The Government Plaintiffs also alleged violations of opacity and PM standards at the Midwest Generation plants. Finally, the Government Plaintiffs alleged that Midwest Generation violated certain operating permit requirements under Title V of the CAA allegedly arising from such claimed PSD, opacity and PM emission violations. In addition to seeking penalties of up to $37,500 per violation, per day, the complaint seeks an injunction ordering Midwest Generation to install controls sufficient to meet BACT emission rates at the units subject to the complaint and other remedies, which could go well beyond the requirements of the CPS. Several environmental groups intervened as plaintiffs in this litigation and filed a complaint, or the Intervenors' Complaint, which alleged opacity, PM and related Title V violations. Midwest Generation filed a motion to dismiss nine of the ten PSD counts in the Governments' Complaint, and to dismiss the tenth PSD count to the extent the Governments' Complaint sought civil penalties for that count. The trial court granted the motion in March 2010.

In June 2010, the Government Plaintiffs and Intervenors each filed an amended complaint. The Governments' Amended Complaint again alleged that Midwest Generation violated PSD (based upon the same projects as alleged in their original complaint, but adding allegations that the Company was liable as the "successor" to ComEd), Title V and opacity and PM standards. It named EME and ComEd as additional defendants and alleged PSD violations (again, premised on the same projects) against them. The Intervenors' Amended Complaint named only Midwest Generation as a defendant and alleged Title V and opacity/PM violations, as well as one of the ten PSD violations alleged in the Governments' Amended Complaint. Midwest Generation again moved to dismiss all but one of the Government Plaintiffs' PSD claims and the related Title V claims. Midwest Generation also filed a motion to dismiss the PSD claim in the Intervenors' Amended Complaint and the related Title V claims. In March 2011, the trial court granted Midwest Generation's partial motion to dismiss the Government Plaintiffs' PSD claims. The trial court denied Midwest Generation's motion to dismiss the PSD claim asserted in the Intervenors' Amended Complaint, but noted that the plaintiffs would be required to convince the court that the statute of limitations should be equitably tolled. The trial court did not address other counts in the amended complaints that allege violations of opacity and PM emission limitations under the Illinois State Implementation Plan and related Title V claims. The trial court also granted the motions to dismiss the PSD claims asserted against EME and ComEd.

Following the trial court ruling, the Government Plaintiffs appealed the trial court's dismissals of their PSD claims, including the dismissal of nine of the ten PSD claims against Midwest Generation and of the PSD claims against the other defendants. Those PSD claim dismissals were affirmed by the U.S. Court of Appeals for the Seventh Circuit in July 2013. In addition, in 2012, all but one of the environmental groups that had intervened in the case dismissed their claims without prejudice. As a result, only one environmental group remains a plaintiff intervenor in the case. The Company does not expect the resolution of this matter to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

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.

National

Court Rejects FERC's Jurisdiction Over Demand Response — On May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated FERC's rules (known as Order No. 745) that allow demand response resources to participate in the FERC-jurisdictional energy markets. The Court of Appeals held that the Federal Power Act does not authorize FERC to exercise jurisdiction over demand response and that instead demand response is part of the retail market over which the states have jurisdiction. The specific order being challenged related to energy market compensation, but this ruling also calls into question whether demand response will be permitted to participate in the capacity markets in the future. The U.S. Court of Appeals for the District of Columbia Circuit issued a stay of its decision in order to allow the U.S. Supreme Court to consider the case. The U.S. Solicitor General, on behalf of FERC, filed a petition for a writ of certiorari on January 15, 2015. On the same date, EnerNOC, Inc. and other private entities filed their own petition for a writ of certiorari in the matter. The Company filed a friend-of-the-court brief with the U.S. Supreme Court on February 17, 2015, supporting the U.S. Solicitor General's and EnerNOC's position and urging the U.S. Supreme Court to grant certiorari. The eventual outcome of this proceeding could result in refunds of payments made for non-jurisdictional services and resettlement of wholesale markets but it is not possible to estimate the impact on the Company at this time.

East Region

RMR 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. On December 8, 2014, FERC approved a contested settlement finalizing the payments associated with the RMR services provided. The Company has made appropriate refunds.

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 previous three years. Montgomery County seeks payment in the amount of $22 million, which includes tax, interest and penalties. The Company is disputing the applicability of the tax. On December 17, 2014, the Maryland Tax Court heard oral arguments from the parties. Additional briefing is underway.

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 District of Columbia Circuit upheld a decision by FERC disclaiming jurisdiction over how the states impose retail station power charges. The ruling of the Court of Appeals allowed the CPUC to establish retail charges for station power consumption. Due to reservation-of-rights language in the California utilities' state-jurisdictional station power tariffs, the ruling of the Court of Appeals may require California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO's station power program.

On November 18, 2011, Southern California Edison Company, or SCE, filed with the CPUC, seeking authorization to begin charging generators retail station power charges, and to assess such charges retroactively, which the Company and other generators challenged. On August 14, 2014, the CPUC approved resolutions setting forth the method to be used by SCE and PG&E to determine station power charges. The resolutions establish 15-minute netting periods, to take effect August 30, 2010, which means that there would be no refund liability associated with station power consumption prior to August 30, 2010. The resolutions are pending rehearing. The Company has accrued sufficient funds to pay the charges for the Company's facilities.

Note 24 — Environmental Matters

NRG is subject to a wide range of environmental laws in the development, construction, ownership and operation of projects. These laws generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Environmental laws 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 GHG, as well as combustion byproducts, water discharge and use, and threatened and endangered species. In general, future laws 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 finalized CSAPR in 2011, which was intended to replace CAIR in January 2012. In December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the implementation of CSAPR and then issued an opinion in August 2012 vacating CSAPR and keeping CAIR in place until the EPA could replace it. On April 29, 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit's decision. In October 2014, the D.C. Circuit lifted the stay of CSAPR. In response, the EPA issued an interim final rule in November 2014 to amend the CSAPR compliance dates. Accordingly, CSAPR replaced CAIR on January 1, 2015. On February 25, 2015, the D.C. Circuit held oral argument regarding several unresolved legal issues and the Company expects a decision in the second quarter of 2015. While NRG cannot predict the final outcome of the ongoing litigation, the Company believes its investment in pollution controls and cleaner technologies coupled with planned plant retirements should leave the fleet well positioned for compliance.

In December 2014, the EPA proposed making the NAAQS for ozone more stringent. The EPA anticipates promulgating a more stringent ozone NAAQS by October 2015. A more stringent NAAQS would obligate the states to develop plans to reduce NO_x (an ozone precursor), which might affect some of the Company's units.

In February 2012, the EPA promulgated standards to control emissions of HAPs from coal and oil-fired electric generating units. The rule established limits for mercury, non-mercury metals, certain organics and acid gases, which limits must be met beginning in April 2015 (with some units getting a 1-year extension). In November 2014, the U.S. Supreme Court agreed to review the D.C. Circuit decision that denied the petitions seeking to vacate MATS but the review will be limited to whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric generating units. The oral argument in the Supreme Court is scheduled for March 2015.

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 June 2014, the EPA proposed a rule that would require states to develop CO_2 standards that would apply to existing fossil-fueled generating facilities. Specifically, the EPA proposed state-specific rate-based goals for CO_2 emissions, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. The EPA anticipates finalizing both of these rules in the summer of 2015.

Water

In August 2014, the EPA finalized the regulation regarding once through cooling from existing facilities to address impingement and entrainment concerns. NRG anticipates that more stringent requirements will be incorporated into some of its water discharge permits over the next several years.

Byproducts, Wastes, Hazardous Materials and Contamination

In December 2014, the EPA released a pre-publication version of a final rule that when published in the Federal Register will regulate byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. In 2010, the EPA had proposed two alternatives. Under the first proposal, these byproducts would be regulated as solid wastes. Under the second proposal, these byproducts would have been 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 have imposed significantly more stringent requirements and materially increased the cost of disposal of coal combustion byproducts. The Company is evaluating the impact of the new rule on its results of operations, financial condition and cash flows.

East Region

In October 2014, the MDE released a draft of a proposed regulation regarding NO_x emissions from coal-fired electric generating units. The MDE draft regulation was proposed in the Maryland Register in December 2014. If finalized as proposed, the regulation would require by June 2020 the Company (at each of the three Dickerson coal-fired units and the Chalk Point coal-fired unit that does not have an SCR) to (1) install and operate an SCR; (2) retire the unit; or (3) convert the fuel source from coal to natural gas. The implementation of the MDE regulation could negatively affect certain of the Company’s coal-fired units in Maryland.

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 2007, Midwest Generation received an NOV from the EPA alleging that past work at Crawford, Fisk, Joliet, Powerton, Waukegan and Will County generating stations violated NSR and other regulations. These alleged violations are the subject of the litigation described in Item 15 — Note 22, Commitments and Contingencies. In January 2009, GenOn received an NOV from the EPA alleging that past work at Keystone, Portland and Shawville generating stations 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 generation stations violated regulations regarding NSR.

In 2008, the PADEP issued an NOV related to the Monarch mine located near the Cheswick generating facility. It has not been mined for many years. The Company's subsidiary discharged approved wastewaters into the Monarch mine including low-volume wastewater from the Cheswick generating facility and leachate collected from ash disposal facilities. The NOV addresses a permit requirement to pump a minimum water volume from the mine. On September 2, 2014, the Company's subsidiary that owns the Cheswick generating facility, the Commonwealth of Pennsylvania and the PADEP entered into a Consent Order and Agreement resolving the NOV. Pursuant to that Consent Order and Agreement, the Company's subsidiary will, among other things, cease wastewater discharges to the mine, construct a waste treatment facility and contribute $200,000 to the Indianola Mine Trust. The Company's subsidiary is currently planning to incur capital expenditures in connection with wastewater from Cheswick and leachate from ash disposal facilities.

In January 2006, NRG's Indian River Power LLC 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 Power LLC 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.

For further discussion of these matters, 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 2015 through 2019 required to comply with environmental laws will be approximately $641 million, which includes $58 million for GenOn and $464 million for EME. 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; (iii) NO_x controls for Sayreville and Gilbert; and (iv) DSI/ESP upgrades at Waukegan and Powerton to satisfy the IL CPS and the Joliet gas conversion.

NRG's contracts with its rural electric cooperative customers in the Gulf Coast 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.

Note 25 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Interest paid, net of amount capitalized	$1,067	$836	$579
Income taxes (refunded)/paid [a]	(6)	(60)	17
Consent fee paid, preferred stock	5	—	—
Non-cash investing and financing activities:			
Additions to fixed assets for accrued capital expenditures	87	405	563
Decrease to fixed assets for accrued grants and related tax impact	(711)	(681)	(87)
Issuance of shares for EME acquisition	(401)	—	—
Issuance of shares for GenOn acquisition	—	—	(2,188)

(a) In 2014, the net income taxes refunded are net of $15 million income taxes paid and $21 million income tax refunds. 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.

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 Company's retail businesses. 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 $22.2 million as of December 31, 2014, 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, 2014					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2013 Total
	(In millions)					
Letters of credit and surety bonds	$1,631	$283	$—	$—	$1,914	$1,701
Asset sales guarantee obligations	35	—	257	—	292	275
Commercial sales arrangements	115	168	8	1,489	1,780	1,554
Other guarantees	73	15	—	1,086	1,174	551
Total guarantees	$1,854	$466	$265	$2,575	$5,160	$4,081

Letters of credit and surety bonds — As of December 31, 2014, NRG and its consolidated subsidiaries were contingently obligated for a total of $1.9 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 obligations associated with future closure and maintenance of ash sites, 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.

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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 U.S., 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, 2014	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 %	$3,162	$(1,443)	$36
Big Cajun II Unit 3, New Roads, LA	58.00 %	191	(105)	14
Cedar Bayou Unit 4, Baytown, TX	50.00 %	215	(57)	—
Keystone, Shelocta, PA	3.70 %	93	(40)	1
Conemaugh, New Florence, PA	3.72 %	99	(42)	1

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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 2014			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$4,192	$4,569	$3,621	$3,486
Operating income	453	549	89	180
Net income/(loss)	97	182	(80)	(67)
Net income/(loss) attributable to NRG Energy, Inc.	$119	$168	$(97)	$(56)
Weighted average number of common shares outstanding — basic	338	338	337	324
Net income/(loss) per weighted average common share — basic	$0.21	$0.49	$(0.30)	$(0.18)
Weighted average number of common shares outstanding — diluted	342	343	337	324
Net income/(loss) per weighted average common share — diluted	$0.20	$0.48	$(0.30)	$(0.18)

	Quarter Ended 2013			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$2,795	$3,490	$2,929	$2,081
Operating (loss)/income	(205)	527	287	(266)
Net (loss)/income	(290)	138	131	(331)
Net (loss)/income attributable to NRG Energy, Inc.	$(297)	$119	$124	$(332)
Weighted average number of common shares outstanding — basic	323	323	323	323
Net (loss)/income per weighted average common share — basic	$(0.92)	$0.36	$0.37	$(1.03)
Weighted average number of common shares outstanding — diluted	323	327	327	323
Net (loss)/income per weighted average common share — diluted	$(0.92)	$0.36	$0.37	$(1.03)

Note 29 — Condensed Consolidating Financial Information

As of December 31, 2014, the Company had outstanding $6.4 billion of Senior Notes due 2018 - 2024, 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, 2014:

Ace Energy, Inc.	NEO Freehold-Gen LLC	NRG Operating Services, Inc.
Allied Warranty LLC	NEO Power Services Inc.	NRG Oswego Harbor Power Operations Inc.
Arthur Kill Power LLC	New Genco GP, LLC	NRG PacGen Inc.
Astoria Gas Turbine Power LLC	Norwalk Power LLC	NRG Portable Power LLC
Bayou Cove Peaking Power LLC	NRG Affiliate Services Inc.	NRG Power Marketing LLC
BidURenergy, Inc.	NRG Artesian Energy LLC	NRG Reliability Solutions LLC
Cabrillo Power I LLC	NRG Arthur Kill Operations Inc.	NRG Renter's Protection LLC
Cabrillo Power II LLC	NRG Astoria Gas Turbine Operations Inc.	NRG Retail LLC
Carbon Management Solutions LLC	NRG Bayou Cove LLC	NRG Retail Northeast LLC
Cirro Group, Inc.	NRG Business Solutions LLC	NRG Rockford Acquisition LLC
Cirro Energy Services, Inc.	NRG Cabrillo Power Operations Inc.	NRG Saguaro Operations Inc.
Clean Edge Energy LLC	NRG California Peaker Operations LLC	NRG Security LLC
Conemaugh Power LLC	NRG Cedar Bayou Development Company, LLC	NRG Services Corporation
Connecticut Jet Power LLC	NRG Connected Home LLC	NRG SimplySmart Solutions LLC
Cottonwood Development LLC	NRG Connecticut Affiliate Services Inc.	NRG South Central Affiliate Services Inc.
Cottonwood Energy Company LP	NRG Construction LLC	NRG South Central Generating LLC
Cottonwood Generating Partners I LLC	NRG Curtailment Solutions LLC	NRG South Central Operations Inc.
Cottonwood Generating Partners II LLC	NRG Development Company Inc.	NRG South Texas LP
Cottonwood Generating Partners III LLC	NRG Devon Operations Inc.	NRG Texas C&I Supply LLC
Cottonwood Technology Partners LP	NRG Dispatch Services LLC	NRG Texas Gregory LLC
Devon Power LLC	NRG Distributed Generation PR LLC	NRG Texas Holding Inc.
Dunkirk Power LLC	NRG Dunkirk Operations Inc.	NRG Texas LLC
Eastern Sierra Energy Company LLC	NRG El Segundo Operations Inc.	NRG Texas Power LLC
El Segundo Power, LLC	NRG Energy Efficiency-L LLC	NRG Warranty Services LLC
El Segundo Power II LLC	NRG Energy Efficiency-P LLC	NRG West Coast LLC
Energy Alternatives Wholesale, LLC	NRG Energy Labor Services LLC	NRG Western Affiliate Services Inc.
Energy Curtailment Specialists, Inc.	NRG Energy Services Group LLC	O'Brien Cogeneration, Inc. II
Energy Plus Holdings LLC	NRG Energy Services International Inc.	ONSITE Energy, Inc.
Energy Plus Natural Gas LLC	NRG Energy Services LLC	Oswego Harbor Power LLC
Energy Protection Insurance Company	NRG Generation Holdings, Inc.	RE Retail Receivables, LLC
Everything Energy LLC	NRG Home & Business Solutions LLC	Reliant Energy Northeast LLC

Forward Home Security, LLC	NRG Home Solutions LLC	Reliant Energy Power Supply, LLC
GCP Funding Company, LLC	NRG Home Solutions Product LLC	Reliant Energy Retail Holdings, LLC
Green Mountain Energy Company	NRG Homer City Services LLC	Reliant Energy Retail Services, LLC
Gregory Partners, LLC	NRG Huntley Operations Inc.	RERH Holdings LLC
Gregory Power Partners LLC	NRG HQ DG LLC	Saguaro Power LLC
Huntley Power LLC	NRG Identity Protect LLC	Somerset Operations Inc.
Independence Energy Alliance LLC	NRG Ilion Limited Partnership	Somerset Power LLC
Independence Energy Group LLC	NRG Ilion LP LLC	Texas Genco Financing Corp.
Independence Energy Natural Gas LLC	NRG International LLC	Texas Genco GP, LLC
Indian River Operations Inc.	NRG Maintenance Services LLC	Texas Genco Holdings, Inc.
Indian River Power LLC	NRG Mextrans Inc.	Texas Genco LP, LLC
Keystone Power LLC	NRG MidAtlantic Affiliate Services Inc.	Texas Genco Operating Services, LLC
Langford Wind Power, LLC	NRG Middletown Operations Inc.	Texas Genco Services, LP
Lone Star A/C & Appliance Repairs, LLC	NRG Montville Operations Inc.	US Retailers LLC
Louisiana Generating LLC	NRG New Roads Holdings LLC	Vienna Operations Inc.
Meriden Gas Turbines LLC	NRG North Central Operations Inc.	Vienna Power LLC
Middletown Power LLC	NRG Northeast Affiliate Services Inc.	WCP (Generation) Holdings LLC
Montville Power LLC	NRG Norwalk Harbor Operations Inc.	West Coast Power LLC
NEO Corporation		

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, 2014

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [a]	Consolidated Balance
	(In millions)				
Operating Revenues					
Total operating revenues	$9,974	$ 6,287	$—	$ (393)	$ 15,868
Operating Costs and Expenses					
Cost of operations	7,909	4,191	4	(325)	11,779
Depreciation and amortization	801	706	16	—	1,523
Impairment losses	—	119	—	(22)	97
Selling, general and administrative	333	405	304	—	1,042
Acquisition-related transaction and integration costs	3	15	66	—	84
Development activity expenses	—	35	56	—	91
Total operating costs and expenses	9,046	5,471	446	(347)	14,616
Gain on sale of assets	—	19	—	—	19
Operating Income/(Loss)	928	835	(446)	(46)	1,271
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	317	219	775	(1,311)	—
Equity in earnings of unconsolidated affiliates	13	33	—	(8)	38
Other income, net	7	14	3	(2)	22
Gain on sale of equity-method investment	—	18	—	—	18
Loss on debt extinguishment	—	(9)	(86)	—	(95)
Interest expense	(19)	(525)	(575)	—	(1,119)
Total other income/(expense)	318	(250)	117	(1,321)	(1,136)
Income Before Income Taxes	1,246	585	(329)	(1,367)	135
Income tax expense/(benefit)	322	159	(478)	—	3
Net Income	924	426	149	(1,367)	132
Less: Net income/(loss) attributable to noncontrolling interests and redeemable noncontrolling interests	—	57	15	(74)	(2)
Net Income Attributable to NRG Energy, Inc	$924	$ 369	$134	$ (1,293)	$ 134

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
For the Year Ended December 31, 2014

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
	(In millions)				
Net Income	$924	$426	$149	$(1,367)	$132
Other Comprehensive (Loss)/Income, net of tax					
Unrealized loss on derivatives, net	(49)	(89)	(215)	308	(45)
Foreign currency translation adjustments, net	—	(12)	4	—	(8)
Available-for-sale securities, net	—	1	(8)	—	(7)
Defined benefit plan, net	5	(104)	(30)	—	(129)
Other comprehensive loss	(44)	(204)	(249)	308	(189)
Comprehensive Income/(Loss)	880	222	(100)	(1,059)	(57)
Less: Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	—	67	15	(74)	8
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	880	155	(115)	(985)	(65)
Dividends for preferred shares	—	—	56	—	56
Comprehensive Income/(Loss) Available for Common Stockholders	$880	$155	$(171)	$(985)	$(121)

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2014

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
	(In millions)				
ASSETS					
Current Assets					
Cash and cash equivalents	$18	$ 1,455	$643	$ —	$ 2,116
Funds deposited by counterparties	9	63	—	—	72
Restricted cash	5	451	1	—	457
Accounts receivable - trade, net	924	392	6	—	1,322
Inventory	537	710	—	—	1,247
Derivative instruments	1,657	1,209	—	(441)	2,425
Deferred income taxes	—	(94)	268	—	174
Cash collateral paid in support of energy risk management activities	114	73	—	—	187
Renewable energy grant receivable	—	134	1	—	135
Accounts receivable - Affiliate	7,449	1,988	(5,991)	(3,437)	9
Prepayments and other current assets	94	269	75	—	438
Total current assets	10,807	6,650	(4,997)	(3,878)	8,582
Net Property, Plant and Equipment	8,344	13,877	171	(25)	22,367
Other Assets					
Investment in subsidiaries	140	2,293	23,410	(25,843)	—
Equity investments in affiliates	(18)	891	—	(102)	771
Notes receivable, less current portion	1	60	109	(98)	72
Goodwill	1,921	653	—	—	2,574
Intangible assets, net	765	1,806	2	(6)	2,567
Nuclear decommissioning trust fund	585	—	—	—	585
Deferred income taxes	(247)	816	837	—	1,406
Derivative instruments	242	288	1	(51)	480
Non-current assets held for sale	—	17	—	—	17
Other non-current assets	113	623	508	—	1,244
Total other assets	3,502	7,447	24,867	(26,100)	9,716
Total Assets	$22,653	$ 27,974	$20,041	$ (30,003)	$ 40,665
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$1	$ 444	$127	$ (98)	$ 474
Accounts payable	598	416	46	—	1,060
Accounts payable - affiliate	1,588	2,447	(598)	(3,437)	—
Derivative instruments	1,532	963	—	(441)	2,054
Deferred income taxes	7	—	(7)	—	—
Cash collateral received in support of energy risk management activities	9	63	—	—	72
Accrued expenses and other current liabilities	283	498	418	—	1,199
Total current liabilities	4,018	4,831	(14)	(3,976)	4,859

Other Liabilities					
Long-term debt and capital leases	307	11,226	8,367	—	19,900
Nuclear decommissioning reserve	310	—	—	—	310
Nuclear decommissioning trust liability	333	—	—	—	333
Postretirement and other benefit obligations	277	234	216	—	727
Deferred income taxes	1,036	(1,012)	(3)	—	21
Derivative instruments	248	241	—	(51)	438
Out-of-market contracts	111	1,133	—	—	1,244
Other non-current liabilities	188	561	98	—	847
Total non-current liabilities	2,810	12,383	8,678	(51)	23,820
Total Liabilities	6,828	17,214	8,664	(4,027)	28,679
2.822% Preferred Stock	—	—	291	—	291
Redeemable noncontrolling interest in subsidiaries	—	19	—	—	19
Stockholders' Equity	15,825	10,741	11,086	(25,976)	11,676
Total Liabilities and Stockholders' Equity	$22,653	$ 27,974	$20,041	$ (30,003)	$ 40,665

(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, 2014

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
	(In millions)				
Cash Flows from Operating Activities					
Net Cash Provided/(Used) by Operating Activities	2,786	268	(4,752)	3,208	1,510
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(2,523)	(685)	3,208	—	—
Acquisition of businesses, net of cash acquired	—	(25)	(2,911)	—	(2,936)
Capital expenditures	(252)	(619)	(38)	—	(909)
Increase in restricted cash, net	—	57	—	—	57
(Increase)/decrease in restricted cash - U.S. DOE projects	—	(209)	3	—	(206)
Decrease in notes receivable	—	25	—	—	25
Proceeds from renewable energy grants	—	916	—	—	916
Purchases of emission allowances	(16)	—	—	—	(16)
Investments in nuclear decommissioning trust securities	(619)	—	—	—	(619)
Proceeds from sale of nuclear decommissioning trust fund securities	600	—	—	—	600
Proceeds from sale of assets, net	—	—	203	—	203
Investments in unconsolidated affiliates	—	(25)	(78)	—	(103)
Other	—	85	—	—	85
Net Cash (Used)/Provided by Investing Activities	(2,810)	(480)	387	—	(2,903)
Cash Flows from Financing Activities					
Proceeds/(payments) from intercompany loans	—	—	3,208	(3,208)	—
Payment of dividends to preferred stockholders	—	—	(196)	—	(196)
Payment for treasury stock	—	—	(39)	—	(39)
Payments for settlement of acquired derivatives that include financing elements	—	9	—	—	9
Proceeds from issuance of long-term debt	—	1,182	3,381	—	4,563
Sale proceeds and other contributions from noncontrolling interests in subsidiaries	—	819	—	—	819
Proceeds from issuance of common stock	—	—	21	—	21
Payment of debt issuance and hedging costs	—	(39)	(28)	—	(67)
Payments for short and long-term debt	—	(1,160)	(2,667)	—	(3,827)
Other	(14)	(4)	—	—	(18)
Net Cash (Used)/Provided by Financing Activities	(14)	807	3,680	(3,208)	1,265
Effect of exchange rate changes on cash and cash equivalents	—	(10)	—	—	(10)

Net (Decrease)/Increase in Cash and Cash Equivalents	(38)	585	(685)	—	(138)
Cash and Cash Equivalents at Beginning of Period	56	870	1,328	—	2,254
Cash and Cash Equivalents at End of Period	$18	$ 1,455	$643	$ —	$ 2,116

(a) All significant intercompany transactions have been eliminated in consolidation.

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 transactions and integration costs	—	70	58	—	128
Development activity expense	—	34	50	—	84
Total operating costs and expenses	7,892	2,845	354	(139)	10,952
Operating Income/(Loss)	331	366	(354)	—	343
Other (Expense)/Income					
Equity in (losses)/earnings of consolidated subsidiaries	(67)	(14)	221	(140)	—
Equity in (losses)/earnings 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 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/(Loss)	$121	$45	$(372)	$(146)	$(352)
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	27	13	(6)	34
Net Income/(Loss) 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/(LOSS)
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/(Loss)	$121	$45	$(372)	$ (146)	$(352)
Other Comprehensive Income/(loss), net of tax					
Unrealized (loss)/gain 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 income	4	93	149	(91)	155
Comprehensive Income/(Loss)	125	138	(223)	(237)	(197)
Less: Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	—	27	13	(6)	34
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	125	111	(236)	(231)	(231)
Dividends for preferred shares	—	—	9	—	9
Comprehensive Income/(Loss) 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 (In millions)	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [a]	Consolidated Balance
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
Accounts receivable - affiliate	4,584	132	(3,834)	(874)	8
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
Current assets held-for-sale	—	19	—	—	19
Prepayments and other current assets	194	228	32	17	471
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 commodity 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
Redeemable noncontrolling interest in subsidiaries	—	2	—	—	2
Stockholders' Equity	14,277	5,096	9,957	(18,863)	10,467
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.

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)				
Cash Flows from Operating Activities					
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 businesses, net of cash acquired		(179)	(315)	—	(494)
Capital expenditures	(528)	(1,413)	(46)	—	(1,987)
(Increase)/decrease in restricted cash, net	(1)	(22)	1	—	(22)
(Increase)/decrease in restricted cash - U.S. DOE projects		(31)	5	—	(26)
Decrease/(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 from sale of assets, net	13	—	—	—	13
Other	(4)	(11)	(20)	—	(35)
Net Cash (Used)/Provided by Investing Activities	(2,261)	(1,601)	1,334	—	(2,528)
Cash Flows from Financing Activities					
Proceeds from intercompany loans	—	—	1,715	(1,715)	—
Payment of dividends to preferred stockholders			(154)	—	(154)
Payment for treasury stock	—	—	(25)	—	(25)
Net (payments of)/receipts from acquired derivatives that include financing elements	(79)	346	—	—	267
Proceeds from issuance of long-term debt	—	1,292	485	—	1,777
Cash proceeds from sale of noncontrolling interest in subsidiary	—	531	—	—	531
Proceeds from issuance of common stock	—	—	16	—	16
Payment of debt issuance and hedging costs	—	(21)	(29)	—	(50)
Payments of 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 (Decrease)/Increase in Cash and Cash Equivalents	(22)	(388)	577	—	167
Cash and Cash Equivalents at Beginning of Period	78	1,258	751	—	2,087
Cash and Cash Equivalents at End of Period	$56	$ 870	$ 1,328	$ —	$ 2,254

(a) All significant intercompany transactions have been eliminated in consolidation.

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.	Eliminations [(a)]	Consolidated Balance