2015 Form 10-K

nrg

Stockholder information

STOCK TRANSFER AGENT AND REGISTRAR

Shareholder correspondence should be mailed to:
Computershare
P.O. BOX 30170
College Station, TX 77842-3170

STOCKHOLDER INQUIRIES

Overnight correspondence should be sent to:
Computershare
211 Quality Circle, Suite 210
College Station, TX 77845

1.866.214.2213

Email: shareholder@computershare.com

Online inquires: https://www-us.computershare.com/investor/Contact

Website: www.computershare.com/investor

Send certificates for transfer and address changes to:
Computershare
P.O. BOX 30170
College Station, TX 77842-3170

STOCK LISTING

NRG's common stock is listed on the New York Stock Exchange under the ticker symbol NRG.

FINANCIAL INFORMATION

NRG's Annual Report on Form 10-K, Proxy Statement and other SEC Filings are available at www.nrg.com under the Investors section.

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

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year ended December 31, 2015.

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

Commission file No. 001-15891

NRG Energy, Inc.

(Exact name of registrant as specified in its charter)

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

(609) 524-4500

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

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

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

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

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 ☐ No ☒

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 ☒ No ☐

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 ☒ No ☐

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. ☒

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 ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $6,713,289,371 based on the closing sale price of $22.88 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, 2016
Common Stock, par value $0.01 per share	314,890,647

Documents Incorporated by Reference:
Portions of the Registrant's definitive Proxy Statement relating to its 2016 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:

AEP	American Electric Power
Alta Wind Assets	Seven wind facilities that total 947 MW located in Tehachapi, California and a portfolio of land leases
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
Average realized prices	Volume-weighted average power prices, net of average fuel costs and reflecting the impact of settled hedges
AZNMSNV	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
CCF	Carbon Capture Facility
CCPI	Clean Coal Power Initiative
CDD	Cooling Degree Day
CDFW	California Department of Fish and Wildlife
CDWR	California Department of Water Resources
CEC	California Energy Commission
CenterPoint	CenterPoint Energy Houston Electric, LLC
CFTC	U.S. Commodity Futures Trading Commission
C&I	Commercial, industrial and governmental/institutional
CO_2	Carbon Dioxide
COD	Commercial Operation Date
ComEd	Commonwealth Edison
Company	NRG Energy, Inc.
Consolidated Appropriations Act	Consolidated Appropriations Act of 2016
CPS	Combined Pollutant Standard
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CVSR	California Valley Solar Ranch
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DGPV Holdco	NRG DGPV Holdco 1 LLC
Direct Energy	Direct Energy Business Marketing, LLC

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 to customers for usage on site, or are projects that are interconnected to sell power into a 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 of 2012
Dominion	Dominion Resources, Inc.
Drop Down Assets	Collectively, the June 2014 Drop Down Assets, the January 2015 Drop Down Assets and the November 2015 Drop Down Assets
DSI	Dry Sorbent Injection with Trona
DSU	Deferred Stock Unit
Dunkirk Power	Dunkirk Power LLC
Economic gross margin	Sum of energy revenue, capacity revenue, retail revenue and other revenue, less cost of sales
EGU	Electric Utility Generating Unit
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
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
ESA	Energy Services Agreement
ESP	Electrostatic Precipitator
ESPP	Amended and Restated 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*
FTRs	Financial Transmission Rights
GenConn	GenConn Energy LLC
GenOn	GenOn Energy, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC
GenOn Americas Generation Senior Notes	GenOn Americas Generation's $694 million outstanding unsecured senior notes consisting of $365 million of 8.5% senior notes due 2021 and $329 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 $1.8 billion outstanding unsecured senior notes consisting of $691 million of 7.875% senior notes due 2017, $649 million of 9.5% senior notes due 2018, and $489 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
HDD	Heating Degree Day
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
HLBV	Hypothetical Liquidation at Book Value
IASB	Independent Accounting Standards Board
ICAP	New York Installed Capacity
IFRS	International Financial Reporting Standards
IL CPS	Illinois Combined Pollutant Standard
ILU	Illinois Union Insurance Company
IPPNY	Independent Power Producers of New York
ISO	Independent System Operator, also referred to as RTOs
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
January 2015 Drop Down Assets	The Laredo Ridge, Tapestry and Walnut Creek projects, which were sold to NRG Yield, Inc. on January 2, 2015
June 2014 Drop Down Assets	The High Desert, Kansas South and El Segundo Projects, which were sold to NRG Yield, Inc. on June 30, 2014
JX Nippon	JX Nippon Oil Exploration (EOR) Limited
Kansas South	NRG Solar Kansas South LLC, the operating subsidiary of NRG Solar Kansas South Holdings LLC, which owns the RE Kansas South project
kV	Kilovolts
kWh	Kilowatt-hour
LA DEQ	Louisiana Department of Environmental Quality
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, as amended, 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
Midwest Generation	Midwest Generation, LLC
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MOPR	Minimum Offer Price Rule
MSU	Market Stock Unit
MW	Megawatts

MWh	Saleable megawatt hour net of internal/parasitic load megawatt-hour
MWt	Megawatts Thermal Equivalent
NAAQS	National Ambient Air Quality Standards
NEPOOL	New England Power Pool
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.
NextEra	NextEra Energy Resources, LLC
NJDEP	New Jersey Department of Environmental Protection
NOL	Net Operating Loss
NOV	Notice of Violation
November 2015 Drop Down Assets	75% of the Class B interests of NRG Wind TE Holdco, which owns a portfolio of 12 wind facilities totaling 814 net MW
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchase Normal Sale
NQSO	Non-Qualified Stock Option
NRC	U.S. Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
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, as amended
NRG Marsh Landing	NRG Marsh Landing, LLC
NRG Wind TE Holdco	NRG Wind TE Holdco LLC
NRG Yield	Reporting segment including the projects belonging to NRG Yield, Inc.
NRG Yield 2019 Convertible Notes	$345 million aggregate principal amount of 3.50% Convertible Senior Notes due 2019 issued by NRG Yield, Inc.
NRG Yield 2020 Convertible Notes	$287.5 million aggregate principal amount of 3.25% Convertible Notes due 2020 issued by NRG Yield, Inc.
NRG Yield, Inc.	NRG Yield, Inc., the owner of 55.3% of the economic interests of NRG Yield LLC with a controlling interest, and issuer of publicly held shares of Class A and Class C 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
Nuclear Waste Policy Act	U.S. Nuclear Waste Policy Act of 1982
NYAG	State of New York Office of Attorney General
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
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 and Electric Company
Pinnacle	Pinnacle Wind, LLC, the operating subsidiary of Tapestry Wind LLC, which owns the Pinnacle project
PJM	PJM Interconnection, LLC
PM	Particulate Matter
POJO	Powerton and Joliet, of which the Company leases 100% interests in Unit 7 and Unit 8 of the Joliet generating facility and the Powerton generating facility, through Midwest Generation
PPA	Power Purchase Agreement
PPTA	Power Purchase Tolling Agreement
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PU	Performance Unit
PUCN	Public Utilities Commission of Nevada
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
RAPA	Resource Adequacy Purchase Agreement
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
REMA	NRG REMA LLC, which leases a 100% interest in the Shawville generating facility and 16.7% and 16.5% interests in the Keystone and Conemaugh generating facilities, respectively
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
RFP	Request For Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROFO Agreement	Amended and Restated Right of First Offer Agreement by and between NRG Energy, Inc. and NRG Yield, Inc.
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standards
RPV Holdco	NRG RPV Holdco 1 LLC
RSSA	Reliability Support Service Agreement
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
Sabine	Sabine Cogen, L.P.
SCE	Southern California Edison Company
SCR	Selective Catalytic Reduction Control System
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission

SECA	Seams Elimination Charge/Cost Adjustments/Assignments
Securities Act	The Securities Act of 1933, as amended
Senior Credit Facility	NRG's senior secured facility, comprised of the Term Loan Facility and the Revolving Credit Facility
Senior Notes	NRG's $6.2 billion outstanding unsecured senior notes consisting of $1.0 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, $936 million of 6.625% senior notes due 2023 and $904 million of 6.25% senior notes due 2024
SERC	Southeastern Electric Reliability Council
SF6	Sulfur Hexafluoride
Sherwin	Sherwin Alumina Company
SIFMA	Securities Industry and Financial Markets Association
SNF	Spent Nuclear Fuel
SO_2	Sulfur Dioxide
S&P	Standard & Poor's
SSR	System Support Resource
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
SunPower	SunPower Corporation, Systems
Taloga	Taloga Wind, LLC, the operating subsidiary of Tapestry Wind LLC, which owns the Taloga project
TCPA	Telephone Consumer Protection Act
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, Inc.'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
TOU	Time-of-use
TSA	Transportation Services Agreement
TSR	Total Shareholder Return
TVA	Tennessee Valley Authority
TWCC	Texas Westmoreland Coal Co.
TWh	Terawatt Hour
UNFCCC	United Nations Framework Convention on Climate Change
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
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 an integrated competitive power company, which 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 has one of the nation's largest and most diverse competitive generation portfolios balanced with the nation's largest competitive retail energy business. The Company owns and operates approximately 50,000 MW 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 names "NRG", "Reliant" and other retail brand names owned by NRG. NRG was incorporated as a Delaware corporation on May 29, 1992.

Strategy

NRG's strategy 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 positioning the Company to meet the market's increasing demand for sustainable, low carbon and customized energy solutions 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.

To 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. The Company is currently executing several key initiatives in connection with its capital allocation plan as further described in Item 7 - *Management's Discussion and Analysis*.

Business

The Company's core businesses include wholesale conventional generation and B2B solutions (included in the NRG Business segment), retail electricity including personal power solutions (included in the NRG Home Retail segment), contracted generation owned by NRG Yield, Inc. (included in the NRG Yield segment) and all other renewable utility scale and distributed generation that is not otherwise owned by NRG Yield, Inc. (included in the NRG Renew segment). In addition, the Company specifically identifies Home Solar as a separate business (included in the NRG Home Solar segment).

Wholesale Generation

The Company's wholesale power generation business includes the Company's wholesale operations including plant operations, commercial operations, EPC, energy services and other critical related functions. In addition to the traditional functions, the wholesale power generation 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.

The wholesale generation 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. The Company has one of the largest and most diversified power generation portfolios in the U.S., with approximately 44,642 MW of fossil fuel and nuclear generation capacity at 90 plants as of December 31, 2015. 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 significant 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 the Company 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 the Company's 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. The Company 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, some 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. The Company believes that its extensive generation portfolio provides many asset optimization opportunities. To that end, the Company currently has approximately 3,397 MW targeted for Repowering and conversion initiatives, all of which is under development or construction.

In addition, the Company continuously evaluates opportunities for development of new generation, on both a merchant and contracted basis. As such, the majority of the Company's current developments are in response to RFPs for new generation and/or generating capacity backed by contracts with credit-worthy counterparties. Many RFPs are issued by regulated utilities or electric system operators in response to reliability or renewable power mandates. The Company competes against other power plant developers when responding to these RFPs. 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.

The Company's B2B solutions focus on providing distributed products and services 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 and electric vehicle charging stations. In providing on-site energy solutions, the Company often benefits from its ability to supply energy products from its wholesale generation portfolio to commercial and industrial retail customers.

The Company also provides energy services including operations, maintenance, technical, development and asset management services to its own facilities and to external customers.

Home Retail

The Company's 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 2015, the retail business delivered approximately 43 TWhs and had approximately 2.77 million Recurring customers, plus approximately 624,000 Discrete customers of products and services. The results of the Company's retail business make it the largest competitive retail energy provider in the U.S. and Texas, and one of the top six competitive retail energy providers in the East. The majority of the Company's retail business sales come 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, NRG's retail business is able to attract, retain, and increase the value of its customer relationships. NRG's retailers are recognized for exemplary customer service, innovative smart energy and technology product offerings and environmentally friendly solutions.

Renewables

The Company’s renewables business consists primarily of the Company’s wind and solar generation facilities that are not owned by NRG Yield, Inc. as well as the Company’s business-to-business distributed solar business. A substantial portion of the wind and solar generation facilities contained within the Company’s renewables business are subject to the ROFO Agreement between the Company and NRG Yield, Inc. In addition, the asset management and operation and maintenance groups within the renewables business manage a portfolio of wind and solar assets across 27 states, and provide a full range of solar energy solutions for utilities, schools, municipalities and businesses.

The business-to-business distributed solar business targets strategic partnerships with local, regional, national and multi-national companies and institutions to provide on-site and off-site renewable generation. As of December 31, 2015, approximately 1,884 MW of utility, C&I, and community renewable projects were in operation inclusive of those held both solely by the Company and in partnership with NRG Yield, Inc. In addition, the distributed solar business' backlog of contracted and awarded projects in the C&I market spans 16 discrete customer programs across 12 states, and includes clients such as Kaiser Permanente, Unilever, and Cisco. In addition to assets in operation, at year end the Company held a pipeline of in-construction and development-stage projects exceeding 850 MW across the C&I, community, and utility renewables markets.

Similar to the wholesale business, the renewables business also competes for new generation opportunities through RFPs. The number and type of competitors vary based on location, generation type, project size and counterparty. The renewables business competes with traditional utilities as well as companies that provide products and services in the downstream solar and wind energy value chains.

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, 2015, NRG owns a 55.1% voting interest in the outstanding common stock of NRG Yield, Inc. NRG Yield, Inc.'s contracted generation portfolio collectively represents 4,438 MW as of December 31, 2015. 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 1,315 net MWt and electric generation capacity of 124 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.

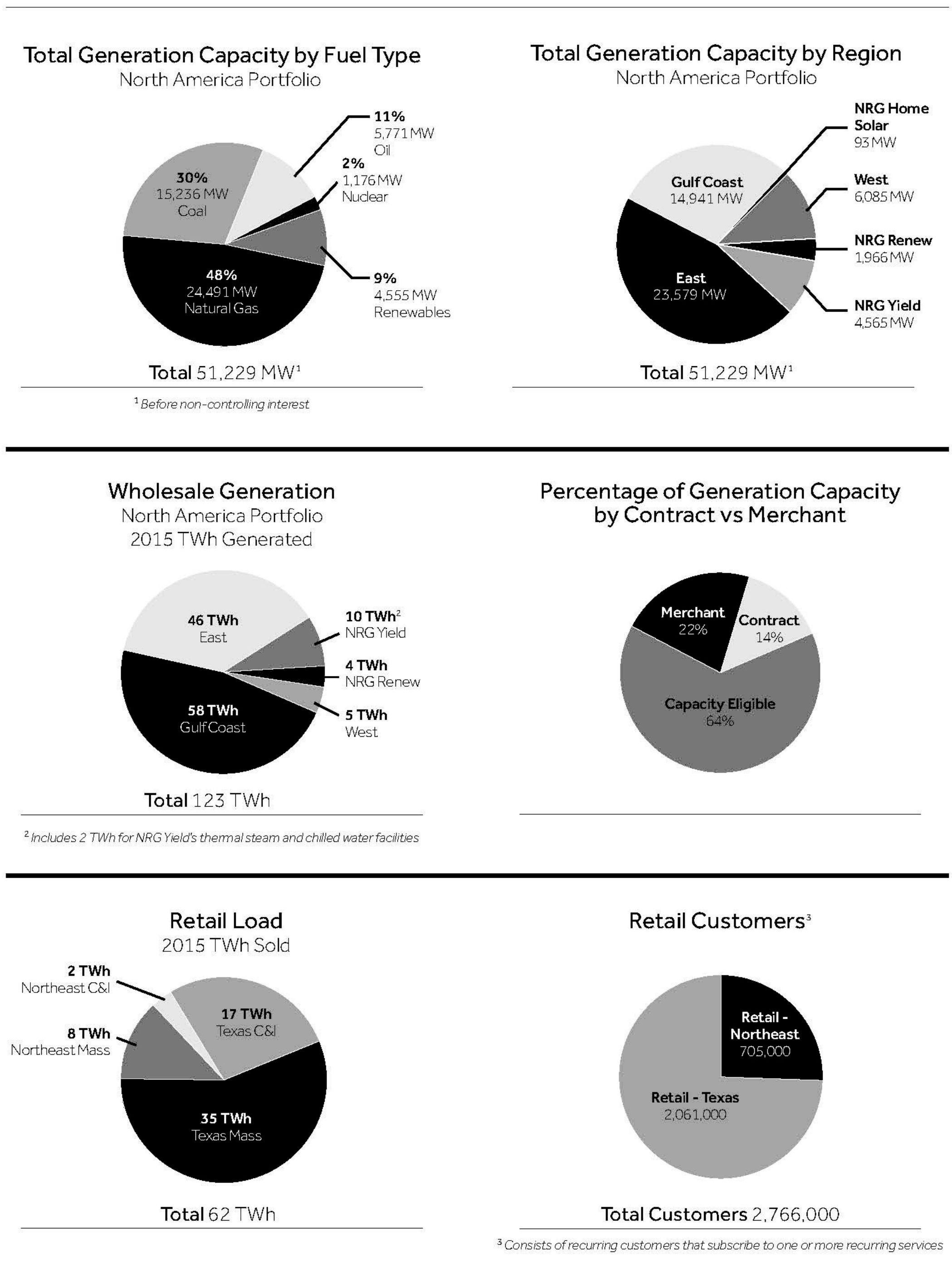
NRG Yield, Inc. provides the Company with a more competitive cost of capital consistent with the lower risk profile of long-term contracted or regulated assets. As such, NRG believes that it directly benefits from NRG Yield, Inc.'s growth through its controlling interest in NRG Yield, Inc. and by providing NRG Yield, Inc. a platform of growth through the completion of future sales of assets pursuant to the ROFO Agreement. The proceeds of such sales are expected to provide the Company with a portion of the capital utilized under its Capital Allocation Program.

Home Solar

The Company's Home Solar business provides installation and contract management services for residential solar customers, allowing customers to switch to solar energy in a simple and cost-efficient manner. The Home Solar business competes against traditional power generation and retail services as well as other solar installation businesses that may offer competitive pricing.

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, 2015, as well as customer, load and regional information surrounding the operation of NRG's retail businesses:



The following table summarizes NRG's global generation portfolio as of December 31, 2015:

	Global Generation Portfolio[a] (In MW)								
	NRG Business								
Generation Type	Gulf Coast	East	West	NRG Home Solar[b]	NRG Renew[c]	NRG Yield [d]	Total Domestic	Other (Inter-national)	Total Global
Natural gas[e]	8,651	7,876	6,085	—	—	1,879	24,491	144	24,635
Coal[f]	5,114	10,122	—	—	—	—	15,236	605	15,841
Oil[g]	—	5,581	—	—	—	190	5,771	—	5,771
Nuclear	1,176	—	—	—	—	—	1,176	—	1,176
Wind	—	—	—	—	1,061	2,005	3,066	—	3,066
Utility Scale Solar	—	—	—	—	845	482	1,327	—	1,327
Distributed Solar	—	—	—	93	60	9	162	—	162
Total generation capacity	14,941	23,579	6,085	93	1,966	4,565	51,229	749	51,978
Capacity attributable to noncontrolling interest	—	—	—	—	(638)	(2,053)	(2,691)	—	(2,691)
Total net generation capacity	14,941	23,579	6,085	93	1,328	2,512	48,538	749	49,287

(a) Includes 90 active fossil fuel and nuclear plants, 16 Utility Scale Solar facilities, 36 wind farms and multiple Distributed Solar facilities. All Utility Scale Solar and Distributed Solar facilities are described in MW on an alternating current basis. MW figures provided represent nominal summer net MW capacity of power generated as adjusted for the Company's owned or leased interest excluding capacity from inactive/mothballed units.

(b) Includes the aggregate production capacity of installed and activated residential solar energy systems. Also includes capacity from operating portfolios of residential solar assets held by RPV Holdco, a partnership between NRG Home Solar and NRG Yield, Inc.

(c) Includes Distributed Solar capacity from assets held by DGPV Holdco, a partnership between NRG Renew and NRG Yield, Inc.

(d) Does not include NRG Yield, Inc.'s thermal converted (MWt) capacity, which is part of the NRG Yield operating segment.

(e) Natural gas generation portfolio does not include: 463 MW related to Osceola, which was mothballed on January 1, 2015; 636 MW related to Coolwater, which was retired on January 1, 2015; 16 MW related to SD Jets Kearny 1, which was deactivated in March 2015; 160 MW related to Glen Gardner, which was retired on May 1, 2015; 98 MW related to Gilbert, which was retired on May 1, 2015; 335 MW related to El Segundo 4, which was deactivated on December 31, 2015; and 60 MW related to SD Jets Kearny 2A-2D, which were deactivated on December 31, 2015.

(f) Coal generation portfolio does not include: 251 MW related to Will County Unit 3, which was retired on April 15, 2015; 597 MW related to Shawville, which was mothballed on May 31, 2015; 575 MW related to Big Cajun Unit 2, which was converted to natural gas in July 2015; 401 MW related to Portland, which was deactivated on December 1, 2015; and 75 MW related to Dunkirk 2, which was mothballed on December 31, 2015.

(g) Oil generation portfolio does not include 212 MW related to Werner, which was retired on May 1, 2015.

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 2020. 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 a portion of the Company's generation in this region. In addition, as of December 31, 2015, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 38% of its expected coal requirement from 2016 to 2020, 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 and related commodity and financial products, including forwards, futures, options and swaps, through its ownership of BETM, which is also an energy management service provider for primarily third-party generating assets. Certain other NRG entities trade to a lesser extent, utilizing similar products as well as oil and weather products. The Company 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, 2015, and through 2019 for the Company's Gulf Coast region:

Gulf Coast	2016	2017	2018	2019	Annual Average for 2016-2019
	(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)]	4,843	4,850	4,692	4,881	4,817
Total Coal and Nuclear Sales (MW) [(c)]	5,108	2,017	1,171	1,018	2,329
Percentage Coal and Nuclear Capacity Sold Forward [(d)]	105%	42%	25%	21%	48%
Total Forward Hedged Revenues [(e)]	$ 1,876	$ 716	$ 470	$ 446	
Weighted Average Hedged Price ($ per MWh) [(e)]	$ 41.80	$ 40.54	$ 45.84	$ 50.05	
Average Equivalent Natural Gas Price ($ per MMBtu) [(e)]	$ 3.51	$ 3.66	$ 4.12	$ 4.43	
Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$ (37)	$ 139	$ 172	$ 190	
Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$ 24	$ (141)	$ (157)	$ (171)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$ 15	$ 86	$ 83	$ 97	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	$ (2)	$ (77)	$ (74)	$ (86)	

(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, 2015, 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, 2015, 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, 2015, and through 2019 for the East region:

East	**2016**	**2017**	**2018**	**2019**	**Annual Average for 2016-2019**
	(Dollars in millions unless otherwise stated)				
Net Coal Capacity (MW) [(a)]	8,295	7,472	7,472	6,256	7,374
Forecasted Coal Capacity (MW) [(b)]	4,250	3,568	2,873	2,235	3,232
Total Coal Sales (MW) [(c)]	4,056	2,021	422	5	1,626
Percentage Coal Capacity Sold Forward [(d)]	95%	57%	15%	—%	42%
Total Forward Hedged Revenues [(e)]	$ 1,554	$ 726	$ 117	$ 2	
Weighted Average Hedged Price ($ per MWh) [(e)]	$ 43.63	$ 41.01	$ 31.58	$ 41.03	
Average Equivalent Natural Gas Price ($ per MMBtu) [(e)]	$ 3.03	$ 3.02	$ 2.87	$ 3.27	
Gas Price Sensitivity Up $0.50/MMBtu on Coal Units	$ 93	$ 200	$ 264	$ 220	
Gas Price Sensitivity Down $0.50/MMBtu on Coal Units	$ (38)	$ (140)	$ (183)	$ (149)	
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal Units	$ 41	$ 88	$ 128	$ 121	
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal Units	$ (31)	$ (73)	$ (94)	$ (88)	

(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, 2015, 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, 2015, 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.

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:

- *Capacity auctions* — The Company's largest sources of capacity revenues are capacity auctions in PJM, ISO-NE, and NYISO. Both ISO-NE and PJM operate a pay-for-performance model where capacity payments are modified based on real-time performance, where NRG's actual revenues will be the combination of revenues based on the cleared auction MWs plus the net of any over- and under-performance of NRG's fleet. PJM integrated a new Capacity Performance product into the market in 2015, as further described in *Regulatory Matters*. In addition, MISO has 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.
- *Resource Adequacy and bilateral contracts* — In California, there is a resource adequacy requirement mandated by law 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 nine Louisiana distribution cooperatives, which expire in 2025. 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. In Texas, capacity and contracted revenues are through bilateral contracts with load serving entities.
- *Long-term PPAs* — Output from the majority of renewable energy assets and certain conventional energy plants is sold through long-term PPAs and tolling agreements to a single counterparty, which is often a utility or commercial customer.

Fuel Supply and Transportation

NRG's fuel requirements consist of various forms of fossil fuel including coal, natural gas, oil and nuclear fuel. The prices of fossil fuels are highly volatile. The Company obtains its fossil fuels from multiple suppliers and through multiple 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 2016. NRG actively manages its coal requirements based on forecasted generation, market volatility and its inventory on site. As of December 31, 2015, NRG had purchased forward contracts to provide fuel for approximately 34% of the Company's expected requirements from 2016 through 2020, excluding inventory. NRG purchased approximately 43 million tons of coal in 2015, 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 2016 through 2020 that have been purchased forward as of December 31, 2015:

	Percentage of Company's Requirement [(a)(b)]
2016	94%
2017	38%
2018	15%
2019	13%
2020	13%

(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) Includes expected coal inventory draw down.

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.

Retail Operations

In 2015, NRG's retail businesses 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 2015, NRG's retail businesses sold approximately 62 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.

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. 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, 2015, and 2014:

	Year Ended December 31, 2015				
			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	14,941	57,679	85.7%	9,651	44.4%
East	23,579	46,289	84.0	10,477	21.6
West	6,085	4,542	86.4	9,189	8.1
NRG Renew	1,966	4,461	95.0	—	39.4
NRG Yield [(a)]	4,565	10,471	95.7	8,651	22.9

	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	59,871	86.6%	9,694	44.6%
East	24,607	51,192	81.6	10,367	24.0
West	7,132	4,241	91.2	9,132	7.1
NRG Renew	1,911	4,026	—	—	—
NRG Yield [(a)]	4,367	8,373	95.5	8,794	23.6

(a) NRG Yield includes thermal generation.

The generation performance by region for the three years ended December 31, 2015, 2014, and 2013, is shown below:

	Net Generation		
	2015	2014	2013
	(In thousands of MWh)		
NRG Business			
Gulf Coast			
Coal	29,301	36,794	37,635
Gas	19,804	13,967	11,674
Nuclear [(a)]	8,574	9,110	7,884
Total Gulf Coast	57,679	59,871	57,193
East			
Coal	36,245	42,939	25,853
Oil	1,583	1,269	364
Gas	8,461	6,984	7,864
Total East	46,289	51,192	34,081
West			
Gas	4,542	4,241	2,876
Total West	4,542	4,241	2,876
NRG Renew			
Solar	2,180	1,901	1,153
Wind	2,281	2,125	534
Total NRG Renew	4,461	4,026	1,687
NRG Yield			
Solar	541	550	520
Wind	5,199	3,427	721
Gas and Dual-Fuel	4,731	4,396	2,589
Total NRG Yield [(b)]	10,471	8,373	3,830

(a) MWh information reflects the Company's undivided interest in total MWh generated by STP.
(b) Total NRG Yield includes thermal heating and chilled water generation.

Segment Review

Effective in December 2014, the Company's segment structure and its allocation of corporate expenses were updated to reflect how management 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 NRG Yield; NRG Yield and corporate activities. The Company's corporate segment includes BETM, international business and electric vehicle services. Intersegment sales are accounted for at market. NRG Yield includes certain of the Company's contracted generation assets. NRG Yield acquired certain assets from the Company, which were accounted for as transfers of entities under common control and accordingly, all historical periods have been recast to reflect these changes:

- On June 30, 2014, El Segundo Energy Center, formerly in the NRG Business segment, Kansas South and High Desert, both formerly in the NRG Renew segment.
- On January 2, 2015, Walnut Creek, formerly in the NRG Business segment, the Tapestry projects (Buffalo Bear, Pinnacle, and Taloga) and Laredo Ridge, both formerly in the NRG Renew segment.
- On November 3, 2015, 75% of the class B interests in NRG Wind TE Holdco, which owns a portfolio of 12 wind facilities, formerly in the NRG Renew segment.

Revenues

The following table contains a summary of NRG's operating revenues by segment for the years ended December 31, 2015, 2014, and 2013, 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, 2015						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[a]	Total Operating Revenues[b]
				(In millions)			
NRG Business	$ 5,743	$ 1,837	$ 1,499	$ (250)	$ 15	$ 298	$ 9,142
NRG Home Retail	—	—	5,389	—	—	—	5,389
NRG Home Solar	—	—	32	—	—	—	32
NRG Renew	444	—	—	(3)	(1)	34	474
NRG Yield	405	341	—	(2)	(54)	179	869
Corporate and Eliminations [b]	(1,098)	(14)	(7)	11	—	(124)	(1,232)
Total	$ 5,494	$ 2,164	$ 6,913	$ (244)	$ (40)	$ 387	$ 14,674

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

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

	Year Ended December 31, 2014						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amor-tization	Other Revenues[c]	Total Operating Revenues[d]
				(In millions)			
NRG Business	$ 6,476	$ 1,787	$ 1,870	$ 535	$ 16	$ 340	$ 11,024
NRG Home Retail	—	—	5,502	—	1	—	5,503
NRG Home Solar	—	—	42	—	—	—	42
NRG Renew	384	1	—	4	(1)	39	427
NRG Yield	270	321	—	2	(29)	182	746
Corporate and Eliminations [d]	(1,708)	(22)	(38)	(40)	—	(66)	(1,874)
Total	$ 5,422	$ 2,087	$ 7,376	$ 501	$ (13)	$ 495	$ 15,868

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

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

	Year Ended December 31, 2013						
	Energy Revenues	Capacity Revenues	Retail Revenues[(f)]	Mark-to-Market Activities	Contract Amortization	Other Revenues[(e)]	Total Operating Revenues
				(In millions)			
NRG Business	$ 5,335	$ 1,720	$ 1,909	$ (540)	$ 20	$ 194	$ 8,638
NRG Home Retail	—	—	4,384	—	(50)	7	4,341
NRG Home Solar	—	—	—	—	—	4	4
NRG Renew	190	—	—	(1)	—	25	214
NRG Yield	111	140	—	—	(1)	137	387
Corporate and Eliminations[(f)]	(2,106)	(60)	(6)	(37)	—	(80)	(2,289)
Total	$ 3,530	$ 1,800	$ 6,287	$ (578)	$ (31)	$ 287	$ 11,295

(e) Primarily consists of revenues generated by the Thermal business, operation and maintenance revenues and unrealized trading activities.
(f) 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 2015, hourly demand ranged from a low of approximately 24,293 MW to a high of approximately 69,877 MW on August 10, 2015, which was a new all-time peak demand record in ERCOT, surpassing the previous record of 68,305 MW, set on August 3, 2011. The ERCOT region contains installed generation capacity of approximately 90,401 MW (approximately 24,190 MW from coal, lignite and nuclear plants, 45,926 MW from gas, and 20,285 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.

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 scarcity price formation, forward market pricing signals and provide incentives for resource investment. Among the changes already implemented are: introduction of an operating reserve demand curve to establish scarcity prices in the real-time market when reserves are depleted, an increase to the system-wide energy and ancillary service offer caps, currently at $9,000 per MWh, an increase to the annual peaker net margin threshold to $315,000 from $175,000, an increase to the low system-wide energy offer cap to $2,000 (up from $500), higher energy pricing for ISO reliability unit commitments for capacity, and energy price adders to offset the price suppressing impacts of out-of-market commitments for reliability.

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 and demand response assets located in the East region of the U.S. are within the control areas of the ISO-NE, NYISO 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. Both ISO-NE and PJM operate a pay-for-performance model where capacity payments are modified based on real-time generator performance. In such markets, NRG’s actual revenues will be the combination of cleared auction MWs times the quantity of MWs cleared, plus the net of any over-performance “bonus payments” and any under-performance charges. Non-performance penalties are set to increase over the next several years to over $3,000/MW-hour. In both markets, bidding rules allow for the incorporation of a risk premium into generator bids.

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, ancillary services and capacity products at market-based rates, either within the CAISO's centralized energy and ancillary service markets or bilaterally pursuant to tolling arrangements or other capacity sale with California's LSEs. The CPUC also determines capacity requirements for LSEs and 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 areas. Additionally, the CAISO has independent authority to contract with needed resources under certain circumstances, typically either when LSEs have failed to procure sufficient resources, or system conditions change unexpectedly.

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.

Renewables

The Company operates a fleet of utility scale and distributed renewable generating assets across the U.S. Many states have implemented their own renewable portfolio standards requiring LSEs to provide a given percentage of their energy sales 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. 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. In December 2015, the U.S. Congress enacted an extension of the 30% solar ITC so that projects which begin construction in 2016 through 2019 will continue to qualify for the 30% ITC. Projects beginning construction in 2020 and 2021 will be eligible for the ITC at the rates of 26% and 22%, respectively. The same legislation also extended the 10-year wind PTC for wind projects which begin construction in years 2016 through 2019. Wind projects which begin construction in the years 2017, 2018 and 2019 are eligible for PTC at 80%, 60% and 40% of the statutory rate per kWh, respectively.

Retail

NRG'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's retail business 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's retail offerings in each state may be impacted by the rules, regulations, market structure and communication requirements from public utility commissions across the country.

Home Solar

The Home Solar business operates in a number of states where solar solutions are attractive and price competitive to consumers. 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. In December 2015, the U.S. Congress enacted an extension of the 30% solar ITC so that projects which begin construction in 2016 through 2019 will continue to qualify for the 30% ITC. Projects beginning construction in 2020 and 2021 will be eligible for the ITC at rates of 26% and 22%, respectively. The ITC reverts to a permanent 10% thereafter.

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. Since 2010, there have been a number of reforms to the regulation of the derivatives markets, both in the U.S. and internationally. These regulations, and any further changes thereto, or adoption of additional regulations, including any regulations relating to position limits on futures and other derivatives or margin for derivatives, could negatively impact the Company’s ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting the Company’s ability to utilize non-cash collateral for derivatives transactions.

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.

U.S. Supreme Court Agrees to Consider the Constitutionality of Maryland's Generator Contracting Programs — On October 19, 2015, the U.S. Supreme Court agreed to hear a case challenging the constitutionality of certain state-directed procurements of new electric generating facilities. The case involves the authority of the Maryland Public Service Commission to direct load-serving utilities in the state to enter into long-term power purchase contracts with a generation developer to encourage the construction of new generation capacity in Maryland. The constitutionality of the long-term contracts was challenged in the U.S. District Court for the District of Maryland, which, in an October 24, 2013, decision, found that the contracts violated the Supremacy Clause of the U.S. Constitution because they were both conflict preempted and field preempted by the FPA and the authority that the FPA granted to FERC. On June 30, 2014, the U.S. Court of Appeals for the Fourth Circuit affirmed the District Court's decision. A case arising out of New Jersey and raising similar issues was decided by the U.S. Court of Appeals for the Third Circuit, which also determined that the state-mandated contracts were preempted. After the Supreme Court granted certiorari in the Maryland case, the Company filed a friend-of-the-court brief urging the Court to uphold the right of states to incentivize new generation by directing utilities in the state to enter into long-term contracts — but noted that FERC has both the authority and the statutory obligation to protect wholesale markets by requiring that bids in the wholesale markets reflect costs and by ensuring that uneconomic entry does not distort auction outcomes. The Supreme Court heard oral argument on February 24, 2016. The outcome of this litigation could have broad impacts on whether and how states require utilities to contract with new generation resources, as well as how such contracted resources interact with the FERC-jurisdictional wholesale markets.

U.S. Supreme Court Allows FERC to Retain Jurisdiction Over Demand Response — On January 25, 2016, the U.S. Supreme Court issued a 6-2 decision affirming FERC’s ability to exercise jurisdiction over demand response resources seeking to voluntarily participate in the wholesale markets. Additionally, the Supreme Court upheld FERC’s preferred scheme for pricing demand response in the energy market. This case arose out of a May 23, 2014, decision by the D.C. Circuit which vacated FERC’s rules (known as Order No. 745) that set the compensation level for demand response resources participating in the FERC-jurisdictional energy markets. The Court of Appeals had held that the FPA 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. With the Supreme Court’s decision, FERC will resume exercising jurisdiction over demand response, which the Company views as a positive for both its wholesale and distributed businesses.

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 1997 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.

STP License Amendment — On November 18, 2015, STP Unit 1 Shutdown Bank Control Rod D6 was determined to be inoperable following a scheduled refueling and maintenance outage. Following extensive analyses, on December 3, 2015, STPNOC submitted an Emergency License Amendment Request to the NRC seeking authorization to operate Unit 1 during the next 18-month operating cycle with 56 full-length control rods instead of 57. The NRC approved the license amendment on December 11, 2015. The approved license amendment supports STP Unit 1 operation with Control Rod D6 and the associated control rod drive shaft removed. STPNOC anticipates seeking a license amendment to allow for the continued operation of Unit 1 in this configuration in the first quarter of 2016.

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. With respect to STP, all currently identified tasks were completed with the conclusion of the refueling outage in December 2015. 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.

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

PJM Auction Results — On August 21, 2015, PJM announced the results of its 2018/2019 Base Residual Auction, officially integrating the new Capacity Performance product into the market. NRG cleared approximately 13,388 MW of Capacity Performance product and 784 MW of Base Capacity product in the 2018/2019 Base Residual Auction. NRG's expected capacity revenues from the 2018/2019 Base Residual Auction are approximately $900 million. PJM announced the results of its Transitional Capacity Auctions for the 2016/2017 and 2017/2018 delivery years, respectively, on August 31, 2015, and September 9, 2015. NRG cleared approximately 3,900 MW of Capacity Performance product in the 2016/2017 Transactional Capacity Auction, and 9,700 MW of Capacity Performance product in the 2017/2018 Transitional Capacity Auction. NRG expects an approximately $425 million increase in PJM capacity revenue from 2016/2017 to 2018/2019 due to the Capacity Performance product.

The table below provides a detailed description of NRG's 2018/2019 Base Residual Auction results:

	Base Capacity Product		Capacity Performance Product	
Zone	Cleared Capacity (MW)(1)	Price ($/MW-day)	Cleared Capacity (MW)(1)	Price ($/MW-day)
COMED	221	$200.21	4,088	$215.00
EMAAC	189	$210.63	981	$225.42
MAAC	68	$149.98	6,618	$164.77
RTO	306	$149.98	1,701	$164.77
Total	784		13,388	

(1) Includes imports. Does not include capacity sold by NRG Curtailment Specialists.

Capacity Performance Rehearings — On June 9, 2015, FERC approved changes to PJM's capacity market. Major elements of the approved changes to the Capacity Performance framework include the calculation of the bid cap, elimination of the 2.5% holdback for short lead-time resources, and substantial performance penalties on Capacity Performance resources that do not perform in real time during specific periods of high demand. The rules mandate that underperformance penalties be paid to units that over perform during those periods of high demand. NRG's actual revenues will be the combination of the revenues based on the cleared auction MW plus the net of any over and under performance of NRG's fleet. On July 9, 2015, multiple parties, including NRG, filed requests for rehearings at FERC regarding the framework of the new annual capacity auctions. Rehearing is pending.

In addition, multiple parties sought clarification on whether demand resources could participate in the Capacity Performance Transition Auctions. On July 22, 2015, FERC issued an order allowing demand response and energy efficiency resources to participate in the Capacity Performance Transition Auctions. Rehearing is pending.

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.

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.

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.

MOPR Revisions — On May 2, 2013, FERC accepted PJM's proposal to substantially revise its Minimum Offer Price Rule. Among other things, FERC approved the portions of the PJM proposal that exempt many new entrants from demonstrating that their proposed projects are economic, as well as providing a similar exemption from 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. 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. On October 15, 2015, FERC denied the requests for rehearing and accepted PJM's compliance filing. The Company, along with other parties, filed a petition for review of FERC's decision with the D.C. Circuit.

AEP and FirstEnergy Ohio Contracts — FirstEnergy and AEP, through their regulated Ohio utilities, have sought approval at the Public Utility Commission of Ohio of a capacity market "swap" where FirstEnergy's and AEP's "merchant" resources would recover the full costs of their generation facilities through a non-bypassable surcharge applicable to all Ohio retail customers. Evidence introduced in the Ohio proceeding suggests that these contracts could impose more than $1,000 per Ohio retail customer in excess costs over the next eight years. A coalition of consumer and supply groups are opposing the proposed contracts before the Public Utility Commission of Ohio. Additionally, NRG and numerous other coalition members have filed a complaint at FERC questioning whether FirstEnergy and AEP have the regulatory approvals necessary to enter into above-market contracts with their generation affiliates without further FERC review. That complaint is pending at FERC.

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

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. FERC denied rehearing. The New England Power Generators Association filed a petition for review of FERC's decision with the D.C. Circuit.

FCM Rules for 2014 Forward Capacity Auction — On February 28, 2014, ISO-NE filed with FERC the results of Forward Capacity Auction 8. On September 16, 2014, FERC issued a notice stating that the Forward Capacity Auction 8 results would go into effect by operation of law. Several parties requested rehearing of FERC's notice. FERC rejected those requests on legal and procedural grounds. A petition for review of FERC's decision was filed with the D.C. Circuit. The Company, along with other parties, filed a brief in support of FERC. An adverse decision could call into question the capacity revenues associated with the 2017/2018 delivery year.

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 as well as an impact on resources that have a price lock-in. FERC denied rehearing. The Company, along with other generators, filed a petition for review of FERC's decision with the D.C. Circuit.

In December 2015, FERC voluntarily requested a remand from the D.C. Circuit. FERC also instituted a FPA Section 206 proceeding, directing ISO-NE to submit tariff revisions by March 31, 2016, providing for zonal sloped demand curves to be implemented beginning in Forward Capacity Auction 11. The ultimate outcome of this proceeding will affect the market design governing future capacity auctions in New England.

Challenge to ISO-NE's Seven-Year Lock-In for New Resources — On February 8, 2016, parties filed a petition in the D.C. Circuit requesting that the Court invalidate FERC's approval of a "price lock" mechanism for new resources in New England. The price lock mechanism permits qualified new resources that clear the auction to receive their first-year clearing price for seven years. Any change to the price lock mechanism could affect future capacity prices in New England, as well as affect the price that already-cleared resources that elected the price lock could receive from the capacity market in future years.

New York

Dunkirk Power Reliability Service and Natural Gas Addition — Dunkirk Power LLC has been operating one unit (Unit 2) under a reliability services agreement with National Grid, or RSSA, through May 31, 2015. On May 18, 2015, the NYSPSC approved National Grid's request for a seven-month extension of the RSSA with Dunkirk to December 31, 2015. Subsequently, National Grid confirmed that Dunkirk would not be needed for reliability past December 31, 2015, and the facility ceased operations at the end of 2015.

In addition, on February 13, 2014, Dunkirk Power LLC and National Grid agreed to a term sheet for a 10-year agreement to govern the addition of natural gas-burning capabilities to the Dunkirk facility. This term sheet, known as the DNG Agreement Term Sheet, was approved by the NYSPSC on June 13, 2014. On February 27, 2015, Entergy filed a complaint in the U.S. District Court for the Northern District of New York alleging that the NYSPSC's approval of the DNG Agreement Term Sheet represents an impermissible interference with FERC's exclusive jurisdiction over the wholesale markets. The U.S. District Court has stayed further discovery until the case goes through summary judgment procedures. In connection with the mothball of the facility, the pending litigation and the latest reliability assessment completed by NYISO, the Company evaluated the related assets for impairment and recorded an impairment loss, as further described in Item 15 - Note 10, *Asset Impairments*, to the Consolidated Financial Statements.

Request for Investigation of NRG's Activities Regarding NRG's Dunkirk Facility — On February 9, 2016, the governor of New York sent a letter to the NYSPSC requesting that it investigate whether NRG acted properly in connection with the reliability services provided by the Dunkirk facility between 2012 and 2015, as well as with respect to NRG's repowering of the Dunkirk facility, both as approved by the NYPSC. The Company believes that the allegations in the letter have no merit and intends to vigorously dispute these allegations.

Huntley Power Reliability Service — On August 25, 2015, Huntley Power filed a notice with the NYSPSC of its intent to retire Huntley's operating units on March 1, 2016. Huntley Power filed a cost-of-service filing but subsequently withdrew the filing after NYISO confirmed that Huntley would not be needed for bulk system reliability.

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 did 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 FERC's order. On October 19, 2015, NYISO filed its tariff revisions at FERC. NRG protested the filing. The matter is pending before FERC.

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 of the FPA 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. On March 30, 2015, NRG filed a request for rehearing. On August 4, 2015, FERC granted in part and denied in part the rehearing requests and conditionally accepted NYISO's compliance filing subject to revisions clarifying that the competitive entry exemption is not available for generator or unforced capacity deliverability rights projects that are members of the completed class years.

Revisions to the Buyer-Side Mitigation Rules — On May 8, 2015, several New York entities, including the NYSPSC, filed a complaint against the NYISO under Section 206 of the FPA seeking revisions to the buyer-side market power mitigation measures of the NYISO tariff. The parties requested FERC to find that the current buyer-side mitigation rules are unjust and unreasonable because they prevent the ICAP market from functioning properly and that the rules should apply only to a limited subset of generation facilities. NRG protested the complaint. On October 9, 2015, FERC held that certain renewables and self-supply resources should be exempt from buyer-side mitigation rules and ordered the NYISO to submit a compliance filing. On February 5, 2016, FERC denied rehearing. The NYISO has yet to issue its compliance filing addressing FERC's order to develop exemptions for certain renewables and self-supply resources. The eventual disposition of this case could impact the ability of uneconomic resources to enter the New York market.

Independent Power Producers of New York (IPPNY) Complaint — On May 10, 2013, as amended on March 25, 2014, 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.

On March 19, 2015, FERC denied IPPNY's complaint and directed NYISO to establish a stakeholder process to consider whether there are circumstances that warrant the adoption of buyer-side mitigation rules in the rest-of-state, and whether mitigation measures would need to be in place to address any price suppressing effects of repowering agreements. On June 17, 2015, NYISO filed its compliance report describing the outcome of the stakeholder process on concluding that buyer-side mitigation measures in the rest-of-state are not warranted. On November 16, 2015, FERC directed the NYISO to provide additional information. On December 16, 2015, NYISO filed responses to FERC's request. Rehearing is pending. Failure to implement buyer-side mitigation measures could result in uneconomic entry, which artificially decreases capacity prices below competitive market levels.

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 and the Houston region. On November 14, 2014, the PUCT denied a challenge by the Company and Calpine Corp. regarding ERCOT's endorsement of the project. Following a contested hearing, in January 2016, the PUCT approved certificates of convenience and necessity authorizing the transmission utilities to proceed with the project which is projected to be operational by the summer of 2018. The project could reduce congestion-related energy prices in the Houston region, where the Company owns several generating stations.

MISO

Complaints regarding the 2015/2016 Planning Resource Auction — In May 2015, the Illinois Attorney General, Public Citizen, Inc., and Southwestern Electric Cooperative, Inc. filed complaints against MISO on the grounds that the results of the MISO 2015/2016 Planning Resource Auction resulted in unjust and unreasonable prices, specifically the auction clearing price in Zone 4. NRG, on behalf of itself and GenOn, filed comments providing its view on the rationale for the market outcome.

On June 30, 2015, the Illinois Energy Consumers filed a complaint with FERC under Section 206 of the FPA regarding MISO's Planning Resource Auction tariff provisions, stating that the current MISO tariff does not produce just and reasonable results. The complaint suggests specific tariff modifications to address these alleged deficiencies, particularly as to the initial reference level price and the failure of the MISO tariff to count capacity sold in neighboring capacity markets toward meeting local clearing requirements in effect for the zones where capacity is physically located. On October 20, 2015, FERC held a technical conference on MISO's Planning Resource Auction, which in part addressed changes to MISO's auction design.

On December 31, 2015, FERC issued an order directing MISO to change key portions of its capacity market tariff, including restricting the ability of suppliers to place offers up to a MISO-developed opportunity cost. FERC mandated several changes to the auction, to be in place before the next planning resource auction in 2016. MISO is pursuing its own stakeholder reforms process to create different rules and implement price formation reforms as to its restructured retail market zones, including Zone 4. FERC expressly declined to rule on the portion of the complaint addressing the outcome of the 2015 Zone 4 auction, and instead stated that its investigation into the conduct of the auction remained pending. Rehearing is pending.

Revisions to MISO Capacity Construct — On November 20, 2015, FERC issued a final order denying the Company's request for rehearing of a 2012 FERC order approving the MISO capacity construct. The Company filed a petition for review of FERC's decision with the D.C. Circuit on the grounds that FERC's order denies merchant generators in MISO's footprint any reasonable opportunity to recover their fixed costs. The eventual outcome of this proceeding could impact MISO's attempts to redesign its capacity markets and thereby affect the value of NRG's uncontracted assets within the MISO footprint.

West Region

Select Net Metering Developments — In California, the CPUC recently issued an order restructuring net energy metering credits. Central to this decision, the CPUC adopted the following for new rooftop systems: (1) continued to support full retail rates for rooftop solar systems for 20 years; (2) imposed some new minor charges on customers installing new systems and (3) mandated time-of-use, or TOU, retail rates, starting immediately. Today's TOU rates generally support the economics of rooftop solar. However, the CPUC has initiated proceedings to develop new TOU rate designs that may lower daytime retail rates and unfavorably affect the economics of installed rooftop solar systems.

The Public Utilities Commission of Nevada, or PUCN, recently revised the compensation structure for net energy metering rooftop solar customers to raise the amounts paid by these customers on utility bills. The Nevada decision applies to both new and existing solar systems without any grandfathering. However, the Nevada Commission recently agreed to a 12-year phase in for implementation of the new rates. The PUCN's decision is currently being appealed.

CAISO

Carlsbad Energy Center — On May 21, 2015, the CPUC approved the Carlsbad Energy Center PPTA for a nominally rated 500 MW five unit natural gas peaking plant. On December 7, 2015, three parties filed two petitions for a writ of review with the California Court of Appeal appealing the CPUC's decision. The petitions remain pending. Additionally, on July 30, 2015, the CEC approved an amendment to the design of the Carlsbad Energy Center. On September 22, 2015, the CEC granted rehearing of its decision approving the amendment to permit the California Department of Fish and Wildlife, or CDFW, to file comments on the proposed decision. On November 12, 2015, the CEC issued an order on rehearing affirming its decision approving the amendment. No party appealed the CEC's decision.

Puente Power Project — On January 11, 2016, the CPUC issued a proposed decision by the assigned administrative law judge and an alternate proposed decision by Commissioner Florio addressing, in part, the resource adequacy purchase agreement, or RAPA, between SCE and NRG for the construction of the 262 MW natural gas peaking Puente Power Project. Both the proposed decision and the Florio alternate proposed decision would delay approval of the RAPA until after the CEC has acted on the permit filing for the Puente Power Project. On February 12, 2016, Commissioner Peterman issued an alternate proposed decision which would approve the RAPA without delay. The soonest the three proposed decisions can be taken up by the CPUC is during its March 17, 2016 business meeting.

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. NRG is also subject to laws regarding the protection of wildlife, including migratory birds, eagles and threatened and endangered species. Environmental laws have become increasingly stringent and NRG expects this trend to continue. The electric generation industry is facing new requirements regarding GHGs, combustion byproducts, water discharge and use, and threatened and endangered species. Future laws may require the addition of emissions controls or other environmental controls or impose restrictions on the operations of the Company's facilities, which could have a material effect on the Company's operations. Complying with environmental laws involves significant capital and operating expenses. NRG decides to invest capital for environmental controls based on the relative certainty of the requirements, an evaluation of compliance options, and the expected economic returns on capital.

A number of regulations with the potential to affect the Company and its facilities are in development, under review or have been recently promulgated by the EPA, including ESPS/NSPS for GHGs, NAAQS revisions and implementation and effluent guidelines. NRG is currently reviewing the outcome and any resulting impact of recently promulgated regulations and cannot fully predict such impact until legal challenges are 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.

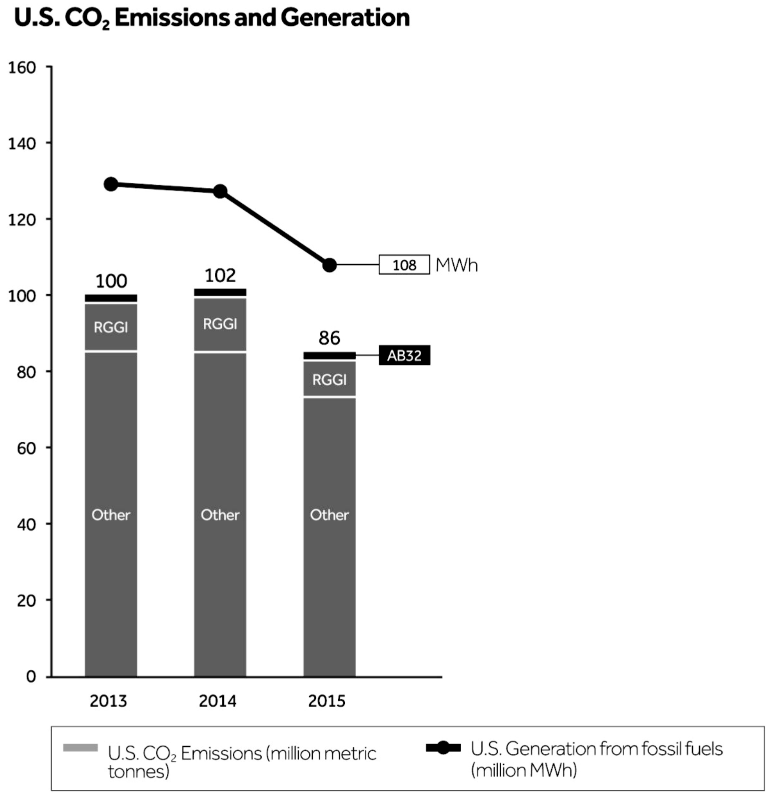
Ozone NAAQS — On October 26, 2015, the EPA promulgated a rule that reduces the ozone NAAQS to 0.070 ppm. This more stringent NAAQS will obligate the states to develop plans to reduce NO_x (an ozone precursor), which could affect some of the Company's units.

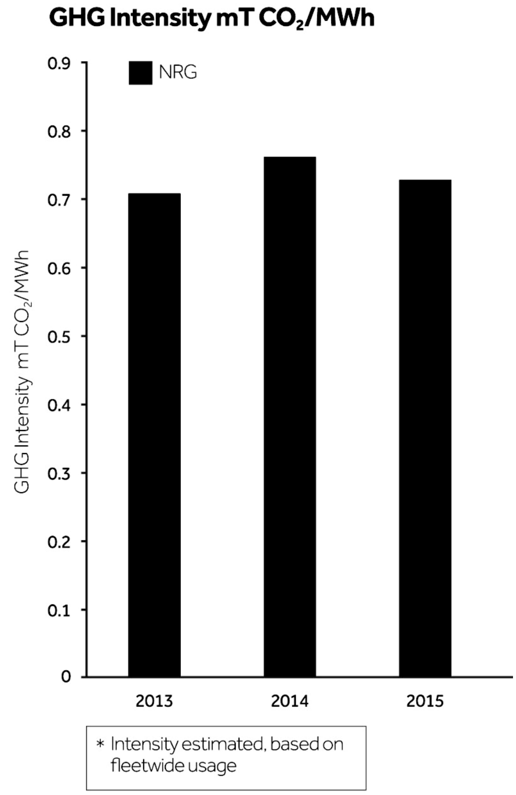
Cross-State Air Pollution Rule — The EPA finalized CSAPR in 2011, which was intended to replace CAIR in January 2012, to address certain state obligations to reduce emissions so that downwind states can achieve federal air quality standards. In December 2011, the D.C. Circuit stayed the implementation of CSAPR and then vacated CSAPR in August 2012 but kept CAIR in place until the EPA could replace it. In April 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 in November 2014 amended the CSAPR compliance dates. Accordingly, CSAPR replaced CAIR on January 1, 2015. On July 28, 2015, the D.C. Circuit held that the EPA had exceeded its authority by requiring certain reductions that were not necessary for downwind states to achieve federal standards. Although the D.C. Circuit kept the rule in place, the D.C. Circuit ordered the EPA to revise the Phase 2 (or 2017) (i) SO_2 budgets for four states including Texas and (ii) ozone-season NO_x budgets for 11 states including Maryland, New Jersey, New York, Ohio, Pennsylvania and Texas. In December 2015, the EPA proposed the CSAPR Update Rule using the 2008 Ozone NAAQS, which would reduce the total amount of ozone season NO_x as compared with the previously utilized 1997 Ozone NAAQS. If finalized, this proposal would reduce future NO_x allocations and/or current banked allowances. While NRG cannot predict the final outcome of this rulemaking, the Company believes its investment in pollution controls and cleaner technologies coupled with planned plant retirements leave the fleet well-positioned for compliance.

MATS — In February 2012, the EPA promulgated standards (the MATS rule) 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 June 2015, the U.S. Supreme Court issued a decision in the case of *Michigan v. EPA* and held that the EPA unreasonably refused to consider costs when it determined that it was "appropriate and necessary" to regulate HAPs emitted by electric generating units. The U.S. Supreme Court did not vacate the MATS rule but rather remanded it to the D.C. Circuit for further proceedings. In November 2015, the EPA proposed a supplemental finding that including a consideration of cost does not alter the EPA's previous determination that it is appropriate and necessary to regulate HAPs, including mercury from power plants. In December 2015, the D.C. Circuit remanded the MATS rule to the EPA without vacatur. While NRG cannot predict the final outcome of this rulemaking, NRG believes that because it has already invested in pollution controls and cleaner technologies, the fleet is well-positioned to comply with the MATS rule.

Clean Power Plan — The national and international attention (including the Paris Agreement) in recent years on GHG emissions has resulted in federal and state legislative and regulatory action. In October 2015, the EPA finalized the Clean Power Plan, or CPP, addressing GHG emissions from existing EGUs. The CPP rule faces numerous legal challenges that likely will take several years to resolve. On February 9, 2016, the U.S. Supreme Court stayed the CPP.

CO_2 Emissions — NRG emits CO_2 when generating electricity at most of its facilities. The graphs presented below illustrate NRG's U.S. emissions of CO_2 for 2013, 2014 and 2015. NRG anticipates reductions in its future emissions profile as the Company modernizes the fleet through repowering, improves generation efficiencies, and explores methods to capture CO_2. By 2030, the Company's goal is to reduce its CO_2 emissions by 50%, using 2014 as a baseline. From 2014 to 2015, the Company's CO_2 emissions decreased from 102 million metric tons to approximately 86 million metric tons, representing a 16% reduction year over year. Factors leading to the decreased emissions include reductions in fleetwide annual net generation due to an overall decrease in market demand and a market-driven shift towards increased generation from natural gas over coal. The Company's goal is to reduce its CO_2 emissions by 90% by 2050.





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 outcome of the legal challenges, 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.

Byproducts, Wastes, Hazardous Materials and Contamination

In April 2015, the EPA finalized the rule regulating byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. The Company is evaluating the impact of the new rule on its results of operations, financial condition and cash flows and has accrued its environmental and asset retirement obligations under the rule based on current estimates as of December 31, 2015.

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws, 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 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 Nuclear Waste Policy 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 Nuclear Waste Policy 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 regarding the use of water for once through cooling at 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 as NPDES permits are renewed.

Effluent Limitations Guidelines — In November 2015, the EPA promulgated a rule revising the Effluent Limitations Guidelines for Steam Electric Generating Facilities, which will impose more stringent requirements (as individual permits are renewed) for wastewater streams from flue gas desulfurization, fly ash, bottom ash, and flue gas mercury control. The Company estimates that it would cost approximately $200 million over the next eight years (the majority of the cost would be incurred after 2019) to comply with this rule at 11 coal-fired plants. This regulation has been challenged and is subject to legal uncertainty. The Company decides to invest capital for environmental controls based on: the certainty of regulations; evaluation of different technologies; options to convert to gas; and the expected economic returns on the capital. Over the next several years, the Company will decide whether to proceed with these investments at each of the plants as permits are renewed based on, among other things, the legal certainty of the regulation and market conditions at that time.

Regional Environmental Issues

East Region

New Source Review — 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.

Burton Island Old Ash Landfill — 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 was 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. 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. In December 2015, DNREC approved the Company's remediation design and the Company's Long Term Stewardship Plan. The cost of completing the work required by the approved remediation plan is consistent with amounts previously budgeted.

Additionally, 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 December 2014, MDE proposed a regulation regarding NO_x emissions from coal-fired electric generating units, which had it been finalized would have required by 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 either (1) install and operate an SCR; (2) retire the unit; or (3) convert the fuel source from coal to natural gas. In early 2015, the State of Maryland decided not to finalize the regulation as proposed. In November 2015, MDE finalized revised regulations to address future NO_x reductions, which although more stringent than previous regulations, will not cause the Company to spend capital to comply. As a result of the new regulations, on February 29, 2016, NRG notified PJM that it was withdrawing the standing deactivation notices for Dickerson Units 1, 2 and 3 and Chalk Point Units 1 and 2.

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. The nine RGGI states are re-evaluating the program and may alter the rules to further reduce the number of allowances. The 2013 rules and/or revisions being currently contemplated could adversely impact NRG's results of operations, financial condition and cash flows.

Gulf Coast Region

Illinois Union Insurance Company Litigation — On October 2, 2015, the U.S. District Court for the Middle District of Louisiana issued an order granting LaGen's motion for summary judgment on its claims for declaratory judgment and breach of contract against ILU for its failure to indemnify LaGen for the costs LaGen paid pursuant to the consent decree that resolved the NSR lawsuit which was brought by the U.S. EPA and LA DEQ against LaGen related to Big Cajun II. The court entered judgment in favor of LaGen for approximately $27 million. In addition, the court ruled that LaGen is entitled to approximately $7 million for future consent decree costs as they are incurred. On October 14, 2015, ILU filed a motion to stay execution of the judgment, which was granted on October 19, 2015. Also, on October 14, 2015, ILU filed a notice to appeal the judgment. On January 14, 2016, the U.S. District Court granted LaGen's motion for attorney's fees of approximately $2 million for the indemnity phase of the litigation. On January 29, 2016, ILU filed their appeal brief with the U.S. Court of Appeals for the Fifth Circuit.

Texas Regional Haze — In January 2016, the EPA promulgated a final rule that requires 15 coal-fired units (at eight plants in Texas) to reduce their SO_2 rates at various times over the next five years. This Regional Haze rule was promulgated under the portion of the CAA that seeks to improve visibility at national parks. Eight of these 15 units already have scrubbers and seven do not. NRG owns two of the affected units, Limestone units 1 and 2, which already have scrubbers. The rule requires that the Limestone units reduce their SO_2 emission rates by 2019. NRG is analyzing the rule as well as exploring what scrubber upgrades and/or operational changes would be most economic to improve the SO_2 rates of Limestone units 1 and 2. If this rule survives legal challenges, NRG anticipates that the affected coal units that do not have scrubbers (none of which belong to NRG) likely would retire by the first quarter of 2021 (but some possibly sooner).

Jewett Mine Closure Costs — NRG is party to a long-term contract with Texas Westmoreland Coal Co., or TWCC, under which TWCC provides the lignite used to fuel NRG's Limestone facility, which is obtained from the Jewett mine, a surface mine adjacent to the Limestone facility. The contract is based on a cost-plus arrangement with incentives and penalties to ensure proper management of the mine. TWCC, the operator of the mine, is responsible for performing reclamation activities at the mine. NRG is responsible for mine reclamation cost obligations and maintains an appropriate ARO.

Environmental Capital Expenditures

NRG estimates that environmental capital expenditures from 2016 through 2020 required to comply with environmental laws will be approximately $350 million which includes $68 million for GenOn and $263 million for Midwest Generation. These costs, the majority of which will be expended by the end of 2016, are primarily associated with (i) DSI/ESP upgrades at the Powerton facility and the Joliet gas conversion to satisfy the IL CPS and (ii) MATS compliance at the Avon Lake facility.

Customers

NRG sells to a wide variety of customers. No individual customer accounted for 10% or more of NRG's total revenue in 2015. 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, 2015, NRG had 10,468 employees, approximately 27% of whom were covered by U.S. bargaining agreements. During 2015, 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.

Risks Related to the Operation of NRG's Business

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

Market prices for power, generation capacity, ancillary services, natural gas, coal and oil are unpredictable and 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 due to 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;
- environmental regulations and legislation;
- electric supply disruptions, including plant outages and transmission disruptions;
- changes in power transmission infrastructure;
- fuel transportation capacity constraints or inefficiencies;
- weather conditions, including extreme weather conditions and seasonal fluctuations, including the affects of climate change;
- changes in commodity prices and the supply of commodities, including but not limited to natural gas, coal and oil;
- 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;
- fuel price volatility;
- economic and political conditions;
- regulations and actions of the ISOs and RTOs;
- federal and state power regulations and legislation;
- changes in law, including judicial decisions;
- changes in prices related to RECs; and
- changes in capacity prices and capacity markets.

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

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

NRG relies on natural gas, coal and oil 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 power sales 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.

Unforeseen changes in the price of coal and natural gas could cause the Company to hold excess coal inventories and incur contract termination costs.

Low natural gas prices can cause natural gas to be the more cost-competitive fuel compared to coal for generating electricity. Because the Company enters into guaranteed supply contracts to provide for the amount of coal needed to operate its base load coal-fired generating facilities, the Company may experience periods where it holds excess amounts of coal if fuel pricing results in the Company reducing or idling coal-fired generating facilities. In addition, the Company may incur costs to terminate supply contracts for coal in excess of its generating requirements.

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' wholesale electricity 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 businesses' wholesale electricity supply costs rise at a greater rate than the rates it charges to customers. The price of wholesale electricity supply purchases associated with the retail businesses' 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 retail businesses' earnings and cash flows could also be adversely affected in any period in which its customers' actual usage of electricity significantly varies from the forecasted usage, which could occur due to, among other factors, weather events, competition and economic conditions.

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 2016 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 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, NRG 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 non-performance penalties 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. 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 flows and financial condition.

Many of NRG's facilities are old and require periodic upgrading, improvement, maintenance and repair. 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 risks, including:

- inability to obtain sufficient funding on reasonable terms and/or necessary government financial incentives;
- 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, including those related to climate change;
- unanticipated cost overruns;
- exchange rate risks; and
- failure of contracting parties to perform under contracts, including EPC contractors.

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 its 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 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 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-related mandates or controls. 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.

The Company'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 the Company's retail businesses.

The Company's retail businesses face competition for customers. Competitors may offer lower prices and other incentives, which may attract customers away from NRG's retail businesses. In some retail electricity markets, the principal competitor may be the incumbent utility. The incumbent utility has the advantage of long-standing relationships with its customers, including well-known brand recognition. Furthermore, NRG'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 and its retail businesses.

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.

The Company’s use and enjoyment of real property rights for its projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to the Company.

Solar and wind projects generally are, and are likely to be, located on land occupied by the project pursuant to long-term easements and leases. The ownership interests in the land subject to these easements and leases may be subject to mortgages securing loans or other liens (such as tax liens) and other easement and lease rights of third parties (such as leases of oil or mineral rights) that were created prior to the project’s easements and leases. As a result, the project’s rights under these easements or leases may be subject, and subordinate, to the rights of those third parties. The Company performs title searches and obtains title insurance to protect itself against these risks. Such measures may, however, be inadequate to protect the Company against all risk of loss of its rights to use the land on which the wind projects are located, which could have a material adverse effect on the Company’s business, financial condition and results of operations.

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 voting interest in NRG Yield, Inc. and the position of certain of its executive officers that are serving the Board of Directors of NRG Yield, Inc. or as executive officers 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 the ownership interests 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 materially 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, 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, 2015, approximately 27% 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 flows. In addition, a number of the Company's employees at NRG's plants are close to retirement. The Company's inability to replace retiring workers could create potential knowledge and expertise gaps as such workers retire.

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

Research and development activities are ongoing to provide alternative and more efficient technologies to produce power, including "clean" coal and coal gasification, wind, photovoltaic (solar) cells, energy storage, and improvements in traditional technologies and equipment, such as more efficient gas turbines. Advances in these or other technologies could reduce the costs of power production to a level below what the Company has currently forecasted, which could adversely affect its cash flows, 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 flows. In addition, significant weather events or terrorist actions could damage or shut down the power transmission and distribution facilities upon which the Company's retail businesses are dependent. Power supply may be sold at a loss if these events cause a significant loss of retail customer load.

The operation of NRG’s businesses is subject to cyber-based security and integrity risk.

Numerous functions affecting the efficient operation of NRG’s businesses are dependent on the secure and reliable storage, processing and communication of electronic data and the use of sophisticated computer hardware and software systems. The operation of NRG’s generation plants, including STP, and of NRG's energy and fuel trading businesses are reliant on cyber-based technologies and, therefore, subject to the risk that such systems could be the target of disruptive actions, particularly through cyber-attack or cyber intrusion, including by computer hackers, foreign governments and cyber terrorists, or otherwise be compromised by unintentional events. As a result, operations could be interrupted, property could be damaged and sensitive customer information could be lost or stolen, causing NRG to incur significant losses of revenues, other substantial liabilities and damages, costs to replace or repair damaged equipment and damage to NRG's reputation. In addition, NRG may experience increased capital and operating costs to implement increased security for its cyber systems and plants.

The Company'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 the Company's retail businesses.

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

Risks Related to Governmental Regulation and Laws

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 legal and regulatory regimes may cause the Company to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of a 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 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 a material 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, non-performance penalties 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 a material 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. In addition, since 2010, there have been a number of reforms to the regulation of the derivatives markets, both in the United States and internationally. These regulations, and any further changes thereto, or adoption of additional regulations, including any regulations relating to position limits on futures and other derivatives or margin for derivatives, could negatively impact NRG’s ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting NRG’s ability to utilize non-cash collateral for derivatives transactions.

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, PTCs, cash grants in lieu of ITCs, loan guarantees, RPS programs, modified accelerated cost-recovery system of depreciation and bonus depreciation. For example, in December 2015, the U.S. Congress enacted an extension of the 30% solar ITC so that projects which begin construction in 2016 through 2019 will continue to qualify for the 30% ITC. Projects beginning construction in 2020 and 2021 will be eligible for the ITC at the rates of 26% and 22%, respectively. The same legislation also extended the 10-year wind PTC for wind projects which begin construction in 2016 through 2019. Wind projects which begin construction in the years 2017, 2018 and 2019 are eligible for PTCs at 80%, 60% and 40% of the statutory rate per kWh, respectively.

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.

The integration of the Capacity Performance product into the PJM market could lead to substantial changes in capacity income and non-performance penalties, which could have a material adverse effect on NRG’s results of operations, financial condition and cash flows.

On June 9, 2015, FERC approved changes to PJM’s capacity market. Major elements of the approved changes to the Capacity Performance framework include the calculation of the bid cap, elimination of the 2.5% holdback for short lead-time resources, and substantial performance penalties on Capacity Performance resources that do not perform in real time during specific periods of high demand. The Company’s Capacity Performance resources may not perform as planned, and the Company may experience substantial changes in capacity income and non-performance penalties, which could have a material adverse effect on NRG’s results of operations, financial condition and cash flows.

Certain of NRG's long-term bilateral contracts result from state-mandated procurements and 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 utilities that are regulated by their respective states, and have been entered into pursuant to certain state programs. Certain long-term contracts that other companies have with state-regulated utilities have been challenged in federal court and have been declared unconstitutional on the grounds that the rate for energy and capacity established by the contracts impermissibly conflicts with the rate for energy and capacity established by FERC pursuant to the FPA. To date, federal district courts in New Jersey and Maryland have struck down contracts on similar grounds, and the U.S. Courts of Appeals for the Third and Fourth Circuits, respectively, have affirmed the lower court decisions. On October 19, 2015, the U.S. Supreme Court granted certiorari in the Fourth Circuit case, and the Court heard oral argument on February 24, 2016. The outcome of this litigation could affect future capacity prices in PJM, as well as the legal status of the Company's bilateral contracts with state-regulated utilities. If certain of the Company's state-mandated 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 flows.

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.

NRG's businesses are subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods and other climatic events, could disrupt NRG's operations and cause it to incur significant costs in preparing for or responding to these effects. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs. Climate change could also affect the availability of a secure and economical supply of water in some locations, which is essential for the continued operation of NRG's generation plants.

GHG regulation could increase the cost of electricity, particularly power generated by fossil fuels, and such increases could have a depressive effect on regional economies. Reduced economic and consumer activity in NRG's service areas — both generally and specific to certain industries and consumers accustomed to previously lower cost power — could reduce demand for the power NRG generates and markets. Also, demand for NRG's energy-related services could be similarly reduced by consumers' preferences or market factors favoring energy efficiency, low-carbon power sources or reduced electricity usage.

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 2015 can be found in Item 1, *Business — Environmental Matters.* On October 23, 2015, the EPA promulgated the final GHG emissions rules for new and existing fossil-fuel-fired electric generating units. The impact of these newly promulgated rules and further legislation or regulation of GHGs on the Company's financial performance will depend on a number of factors, including future legal challenges to promulgated regulations, the level of GHG standards, the extent to which mitigation is required, the availability of offsets, and the extent to which NRG will 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. The nine RGGI states are re-evaluating the program and may alter the rules to further reduce the number of allowances. The 2013 rules and/or revisions being currently contemplated 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.

On October 26, 2015, the EPA promulgated a rule that reduces the ozone NAAQS to 0.070 ppm. This more stringent NAAQS will obligate the states to develop plans to reduce NO_x (an ozone precursor), which could affect some of the Company's units. EPA guidance for these plans is expected in late 2016.

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 retail businesses are subject to changing state rules and regulations that could have a material impact on the profitability of its business lines.

The competitiveness of NRG's retail businesses 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, which can include controls on the retail rates NRG's retail businesses can charge, the imposition of additional costs on sales, restrictions on the Company's ability to obtain new customers through various marketing channels and disclosure requirements, which can affect the competitiveness of NRG's retail businesses. Additionally, state or federal imposition of 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 retail offerings. NRG's retail businesses have 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'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, which risks may negatively impact the Company's business.

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.

The Company may potentially be affected by emerging technologies that may over time affect change in capacity markets and the energy industry overall with the inclusion of distributed generation and clean technology.

Some technologies like, distributed renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices could affect the price of energy. These distributed technologies may affect the financial viability of utility counterparties and could have significant impacts on wholesale market prices.

Risks Related to Economic and Financial Market Conditions

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.

Adverse economic conditions could adversely affect NRG's business, financial condition, results of operations and cash flows.

Adverse economic conditions and declines in wholesale energy prices, partially resulting from adverse economic conditions, may impact NRG's earnings. The breadth and depth of negative economic conditions may have a wide-ranging impact on the U.S. business environment, including NRG's businesses. In addition, adverse economic conditions also reduce the demand for energy commodities. Reduced demand from negative economic conditions continues to impact the key domestic wholesale energy markets NRG serves. The combination of lower demand for power and increased supply of natural gas has put downward price pressure on wholesale energy markets in general, further impacting NRG's energy marketing results. In general, economic and commodity market conditions will continue to impact NRG's unhedged future energy margins, liquidity, earnings growth and overall financial condition. In addition, adverse economic conditions, declines in wholesale energy prices, reduced demand for power and other factors may negatively impact the trading price of NRG's common stock and impact forecasted cash flows, which may require NRG to evaluate its goodwill and other long-lived assets for impairment. Any such impairment could have a material impact on NRG's financial statements.

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 net deferred tax assets that the Company estimates as 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 accordingly 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.

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, 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.

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 and fairly compensate NRG's generation units;
- NRG's ability to mitigate forced outage risk as it becomes subject to capacity performance requirements in PJM and new performance incentives in ISO-NE;
- NRG's ability to borrow 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 develop and innovate new products as retail and wholesale markets continue to change and evolve;
- NRG's ability to implement its strategy of finding ways to meet the challenges of climate change, clean air and protecting natural resources while taking advantage of business opportunities;
- 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 engage in successful mergers and acquisitions activity;
- 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, 2015. The MW figures provided represent nominal summer net MW capacity of power generated as adjusted for the Company's owned or leased interest excluding capacity from inactive/mothballed units as of December 31, 2015. 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	MISO	100.0	580	Coal
Big Cajun II, New Roads, LA	MISO	100.0	540	Natural Gas
Big Cajun II, New Roads, LA	MISO	58.0	341	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	TVA[(e)]	100.0	800	Natural Gas
Cottonwood, Deweyville, TX	MISO	100.0	1,263	Natural Gas
Greens Bayou, Houston, TX	ERCOT	100.0	715	Natural Gas
Gregory, Corpus Christi, TX	ERCOT	100.0	388	Natural Gas
Limestone, Jewett, TX	ERCOT	100.0	1,689	Coal
San Jacinto, LaPorte, TX	ERCOT	100.0	162	Natural Gas
South Texas Project, Bay City, TX [(f)]	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[(g)]	ERCOT	100.0	1,183	Natural Gas
	Total net Gulf Coast Region		14,941	
East Region				
Arthur Kill, Staten Island, NY	NYISO	100.0	858	Natural Gas
Astoria Gas Turbines, Queens, NY	NYISO	100.0	404	Natural Gas
Astoria Oil Turbines, Queens, NY	NYISO	100.0	104	Oil
Aurora, IL	PJM	100.0	878	Natural Gas
Avon Lake, OH	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	1,147	Natural Gas
Brunot Island, Pittsburgh, PA	PJM	100.0	244	Natural Gas
Brunot Island, Pittsburgh, PA	PJM	100.0	15	Oil
Canal, Sandwich, MA	ISO-NE	100.0	1,112	Oil
Chalk Point, Aquasco, MD [(h)]	PJM	100.0	667	Coal
Chalk Point, Aquasco, MD	PJM	100.0	1,648	Natural Gas
Chalk Point, Aquasco, MD	PJM	100.0	42	Oil
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 [(h)]	PJM	100.0 [(b)]	537	Coal

Dickerson, MD	PJM	100.0	(b)	294	Natural Gas
Dickerson, MD	PJM	100.0	(b)	18	Oil
Fisk, Chicago, IL	PJM	100.0		172	Oil
Gilbert, Milford, NJ	PJM	100.0		438	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(i)	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 (j)	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	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	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		217	Natural Gas
Seward, New Florence, PA	PJM	100.0		525	Coal
Shawnee, East Stroudsburg, PA	PJM	100.0		20	Oil
Shawville, PA	PJM	100.0	(b)	6	Oil
Shelby County, Neoga, IL	MISO	100.0		352	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
Will County, Romeoville, IL	PJM	100.0		510	Coal
		Total net East Region		23,579	
West Region					
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) (k)	CAISO	100.0		112	Natural Gas
Sunrise, Fellows, CA	CAISO	100.0		586	Natural Gas
Watson, Carson, CA	CAISO	49.0		204	Natural Gas
		Total net West Region		6,085	
		Total net NRG Business		44,605	

NRG Renew:				
Agua Caliente, Dateland, AZ	CAISO/WECC	51.0	290	Solar
Bingham Lake, MN	MISO	99.0	15	Wind
Broken Bow, NE	MISO	31.0	80	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., Brawley, CA	CAISO	100.0	6	Solar
Community Wind North, Lake Benton, MN	MISO	99.0	30	Wind
Crofton Bluffs, NE	MISO	31.0	42	Wind
Crosswinds, Aryshire, IA	MISO	24.8	5	Wind
Distributed Solar	AZNMSNV/WECC	100.0	60	Solar
Eastridge, Lake Wilson, MN	MISO	100.0	10	Wind
Elbow Creek Wind Farm, Howard County, TX	ERCOT	25.0	30	Wind
Elkhorn Ridge, Bloomfield, NE	MISO	16.8	13	Wind
Forward, Berlin, PA	PJM	25.0	7	Wind
Georgia Solar Holdings, GA	SERC	20.1	1	Solar
Goat Mountain, Sterling City, TX	ERCOT	25.0	37	Wind
Guam, Inarajan, Guam		100.0	26	Solar
Hardin, Jefferson, IA	MISO	24.8	4	Wind
High Lonesome, Willard, NM	MISO	100.0	100	Wind
Ivanpah, Ivanpah Dry Lake, CA	CAISO	50.1	390	Solar
Jeffers, MN	MISO	99.9	50	Wind
Langford Wind Farm, Christoval, TX	ERCOT	100.0	150	Wind
Lookout, Berlin, PA	PJM	25.0	9	Wind
Mountain Wind I, Fort Bridger, WY	WECC	31.0	61	Wind
Mountain Wind II, Fort Bridger, WY	WECC	31.0	80	Wind
Odin, MN	MISO	25.0	5	Wind
San Juan Mesa, Elida, NM	MISO	18.8	22	Wind
Sherbino Wind Farm, Pecos County, TX	ERCOT	50.0	75	Wind
Sleeping Bear, Woodward, OK	SPP	25.0	24	Wind
Spanish Fork, UT	WECC	25.0	5	Wind
Spanish Town, St. Croix, U.S. Virgin Islands		100.0	4	Wind
Westridge, Pipestone, MN	MISO	96.9	17	Wind
Wildorado, Vega, TX	ERCOT	25.0	40	Wind
		Total NRG Renew	1,966	
		NRG Renew capacity attributable to noncontrolling interest	(638)	
		Total net NRG Renew	1,328	
NRG Home Solar:				
Residential Solar		100.0	93	Solar
		Total net NRG Home Solar	93	
NRG Yield:				
Alpine, Lancaster, CA	CAISO	100.0	66	Solar
Alta Wind, Tehachapi, CA	CAISO	100.0	947	Wind
Avenal, CA	CAISO	50.0	23	Solar
Avra Valley, Pima County, AZ	CAISO	100.0	26	Solar
Blythe, CA	CAISO	100.0	21	Solar
Borrego, Borrego Springs, CA	CAISO	100.0	26	Solar
Buffalo Bear, Buffalo, OK	SPP	100.0	19	Wind
California Valley Solar Ranch, San Luis Obispo County, CA	CAISO/WECC	49.0	122	Solar

Crosswinds, Aryshire, IA	MISO	74.3	16	Wind
Desert Sunlight, Riverside, CA	CAISO	25.0	138	Solar
Distributed Solar, AZ	AZNMSNV	100.0	5	Solar
Distributed Solar, CA	WECC	51.0	4	Solar
Dover Cogeneration, DE	PJM	100.0	104	Natural Gas
Elbow Creek, Howard County, TX	ERCOT	75.0	92	Wind
Elkhorn Ridge, Bloomfield, NE	MISO	50.3	41	Wind
El Segundo Energy Center, CA	CAISO	100.0	550	Natural Gas
Forward, Berlin, PA	PJM	75.0	22	Wind
GenConn Devon, Milford, CT	ISO-NE	50.0	95	Dual-fuel
GenConn Middletown, CT	ISO-NE	50.0	95	Dual-fuel
Goat Wind, Sterling City, TX	ERCOT	74.9	113	Wind
Hardin, Jefferson, IA	MISO	74.3	11	Wind
High Desert, Lancaster, CA	WECC	100.0	20	Solar
Kansas South, Lemoore, CA	WECC	100.0	20	Solar
Laredo Ridge, Petersburg, NE	MISO	100.0	80	Wind
Lookout, Berlin, PA	PJM	75.0	29	Wind
Marsh Landing, Antioch, CA	CAISO	100.0	720	Natural Gas
Odin, MN	MISO	74.9	15	Wind
Paxton Creek Cogeneration, Harrisburg, PA	PJM	100.0	12	Natural Gas
Pinnacle, Keyser, WV	PJM	100.0	55	Wind
Princeton Hospital, NJ [l]	PJM	100.0	5	Natural Gas
Roadrunner, Santa Teresa, NM	WECC	100.0	20	Solar
San Juan Mesa, Elida, NM	MISO	56.3	68	Wind
Sleeping Bear, Woodward, OK	SPP	75.0	71	Wind
South Trent Wind Farm, Sweetwater, TX	ERCOT	100.0	101	Wind
Spanish Fork, UT	WECC	75.0	14	Wind
Spring Canyon II and III	WECC	90.1	60	Wind
Taloga, Putnam, OK	SPP	100.0	130	Wind
Tucson Convention Center, Tucson, AZ	WECC	100.0	2	Natural Gas
University of Bridgeport, CT	ISO-NE	100.0	1	Natural Gas
Walnut Creek, City of Industry, CA	CAISO	100.0	485	Natural Gas
Wildorado, Vega, TX	ERCOT	74.9	121	Wind
		Total NRG Yield	4,565	
		NRG Yield capacity attributable to noncontrolling interest	(2,053)	
		Total net NRG Yield	2,512	
International 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	51,978	
		Total capacity attributable to noncontrolling interest	(2,691)	
		Total net generation capacity	49,287	

(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 312 MW and 248 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) Dual interconnect between TVA and MISO.
(f) Generation capacity figure consists of the Company's 44% interest in the two units at STP.
(g) W.A. Parish Unit Petra Nova GT2 (75 MW of the 1,220 MW at W.A. Parish Natural Gas) is currently mothballed for purposes of construction in connection with the Petra Nova project with an expected return to service in the third quarter of 2016.
(h) On February 29, 2016, NRG notified PJM that it was withdrawing the standing deactivation notices for Chalk Point Units 1 and 2 and Dickerson Units 1, 2 and 3.
(i) NRG plans to retire the units on March 1, 2016.
(j) NRG intends to add natural gas burning capability to Units 6, 7 and 8 of the Joliet coal facility by the summer of 2016.
(k) NRG operates these units, located on property owned by SDG&E, under a license agreement which is set to end on December 31, 2016.
(l) The output of Princeton Hospital is primarily dedicated to serving the hospital. Excess power is sold to the local utility under its state-jurisdictional tariff.

Thermal Facilities

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

The following table summarizes NRG's thermal steam and chilled water facilities as of December 31, 2015:

Name and Location of Facility	% Owned	Thermal Energy Purchaser	Megawatt Thermal Equivalent Capacity (MWt)	Generating Capacity
NRG Energy Center Minneapolis, MN	100.0	Approx. 100 steam and 50 chilled water customers	322 136	Steam: 1,100 MMBtu/hr. Chilled water: 38,700 tons
NRG Energy Center San Francisco, CA	100.0	Approx 175 steam customers	133	Steam: 454 MMBtu/hr.
NRG Energy Center Omaha, NE	100.0 12.0[(a)] 100.0 0%[(a)]	Approx 60 steam and 60 chilled water customers	142 73 77 26	Steam: 485 MMBtu/hr Steam: 250 MMBtu/hr Chilled water: 22,000 tons Chilled water: 7,250 tons
NRG Energy Center Harrisburg, PA	100.0	Approx 140 steam and 3 chilled water customers	108 13	Steam: 370 MMBtu/hr. Chilled water: 3,600 tons
NRG Energy Center Phoenix, AZ	0%[(a)] 100.0 12.0[(a)] 0%[(a)]	Approx 35 chilled water customers	4 104 14 28	Steam: 13 MMBtu/hr Chilled water: 29,600 tons Chilled water: 3,950 tons Chilled water: 8,000 tons
NRG Energy Center Pittsburgh, PA	100.0	Approx 25 steam and 25 chilled water customers	88 46	Steam: 302 MMBtu/hr. Chilled water: 12,934 tons
NRG Energy Center San Diego, CA	100.0	Approx 15 chilled water customers	31	Chilled water: 7,425 tons
NRG Energy Center Dover, DE	100.0	Kraft Foods Inc. and Procter & Gamble Company	66	Steam: 225 MMBtu/hr.
NRG Energy Center Princeton, NJ	100.0	Princeton HealthCare System	21 17	Steam: 72 MMBtu/hr. Chilled water: 4,700 tons
		Total Generating Capacity (MWt)	1,449	

(a) Net MWt capacity excludes 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

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, Texas, its retail business offices and call centers, and various other office space.

During 2016, NRG expects to move its 211 Carnegie Center, Princeton, New Jersey headquarters to a newly leased headquarters at 804 Carnegie Center, Princeton, New Jersey, which is currently under construction.

Item 3 — Legal Proceedings

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

Item 4 — Mine Safety Disclosures

Not applicable.

PART II

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

Market Information and Holders

NRG's authorized capital stock consists of 500,000,000 shares of NRG common stock and 10,000,000 shares of preferred stock. A total of 22,000,000 shares of the Company's common stock are 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 — S*ecurity Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* and Item 15 — Note 20, *Stock-Based Compensation*, to the Consolidated Financial Statements. 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 2015 and 2014 are set forth below:

Common Stock Price	Fourth Quarter 2015	Third Quarter 2015	Second Quarter 2015	First Quarter 2015	Fourth Quarter 2014	Third Quarter 2014	Second Quarter 2014	First Quarter 2014
High	$ 16.11	$ 23.22	$ 26.93	$ 27.90	$ 33.92	$ 37.39	$ 38.09	$ 32.04
Low	8.80	14.43	22.83	22.78	25.77	28.97	31.50	26.57
Closing	11.77	14.85	22.88	25.19	26.95	30.48	37.20	31.80
Dividends Per Common Share	$ 0.145	$ 0.145	$ 0.145	$ 0.145	$ 0.140	$ 0.140	$ 0.140	$ 0.120

NRG had 314,190,042 shares outstanding as of December 31, 2015. As of January 31, 2016, there were 314,890,647 shares outstanding, and there were 26,138 common stockholders of record.

Dividends

On January 18, 2016, NRG declared a quarterly dividend on the Company's common stock of $0.145 per share, or $0.58 per share on an annualized basis, payable on February 16, 2016, to stockholders of record as of February 1, 2016.

The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws and regulations. On February 29, 2016, the Company announced a reduction in its common stock dividend to $0.12 per share on an annualized basis.

Repurchase of equity securities

The Company's board of directors authorized share repurchases of $481 million of its common stock under the 2015 Capital Allocation Program which began in December 2014 and was completed during 2015.

The following table reflects the repurchases made under the 2015 Capital Allocation Program during the three months ended December 31, 2015:

For the Three Months Ended December 31, 2015	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)
October 1, 2015 to October 31, 2015	5,558,920	$ 15.03	5,558,920	—
November 1, 2015 to November 30, 2015	—	—	—	—
December 1, 2015 to December 31, 2015	—	—	—	—
Total	5,558,920	$ 15.03	5,558,920	$ —

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

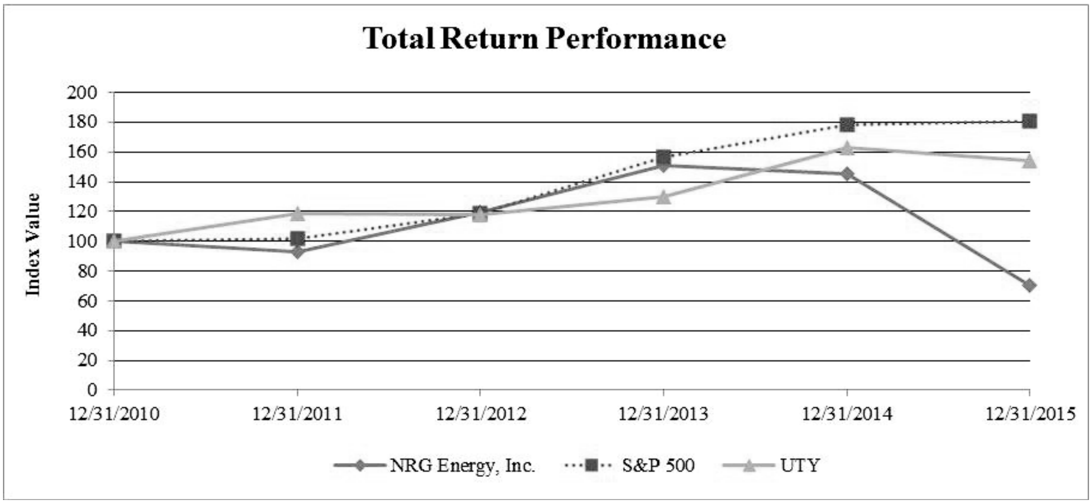
(b) Includes commissions of $0.015 per share paid in connection with the share repurchases.

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, 2010, through December 31, 2015, 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, 2010, 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-2010	Dec-2011	Dec-2012	Dec-2013	Dec-2014	Dec-2015
NRG Energy, Inc.	$ 100.00	$ 92.73	$ 119.50	$ 151.28	$ 145.09	$ 70.37
S&P 500	100.00	102.11	118.45	156.82	178.28	180.75
UTY	100.00	118.74	118.13	129.84	162.86	153.85

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,				
	2015	2014	2013	2012	2011
	(In millions except ratios and per share data)				
Statement of income data:					
Total operating revenues	$ 14,674	$ 15,868	$ 11,295	$ 8,422	$ 9,079
Total operating costs and expenses, and other expenses [(a)]	14,703	15,655	11,371	8,432	9,070
Impairment losses	5,030	97	459	—	160
Operating (loss)/income	(4,040)	1,271	343	350	635
Impairment losses on investments	56	—	99	2	495
(Loss)/income from continuing operations, net	(6,436)	132	(352)	315	197
Net (loss)/income attributable to NRG Energy, Inc.	$ (6,382)	$ 134	$ (386)	$ 295	$ 197
Common share data:					
Basic shares outstanding — average	329	334	323	232	240
Diluted shares outstanding — average	329	339	323	234	241
Shares outstanding — end of year	314	337	324	323	228
Per share data:					
Net (loss)/income attributable to NRG — basic	$ (19.46)	$ 0.23	$ (1.22)	$ 1.23	$ 0.78
Net (loss)/income attributable to NRG — diluted	(19.46)	0.23	(1.22)	1.22	0.78
Dividends declared per common share	0.58	0.54	0.45	0.18	—
Book value	$ 17.29	$ 34.67	$ 32.33	$ 31.83	$ 33.71
Business metrics:					
Cash flow from operations	$ 1,309	$ 1,510	$ 1,270	$ 1,149	$ 1,166
Liquidity position [(b)]	$ 3,305	$ 3,940	$ 3,695	$ 3,362	$ 2,328
Ratio of earnings to fixed charges	(3.27)	1.14	0.45	0.84	0.77
Ratio of earnings to fixed charges and preferred dividends	(3.18)	1.06	0.45	0.83	0.76
Return on equity	(117.45)%	1.15%	(3.69)%	2.87%	2.57%
Ratio of debt to total capitalization	75.95 %	60.41%	57.60 %	56.74%	52.43%
Balance sheet data:					
Current assets	$ 7,391	$ 8,408	$ 7,596	$ 7,972	$ 7,749
Current liabilities	4,375	4,859	4,204	4,670	5,861
Property, plant and equipment, net	18,732	22,367	19,851	20,153	13,621
Total assets	32,882	40,466	33,902	34,983	26,900
Long-term debt, including current maturities, and capital leases [(c) (d)]	19,636	20,374	16,817	15,883	9,832
Total stockholders' equity	$ 5,434	$ 11,676	$ 10,467	$ 10,269	$ 7,669

(a) Excludes impairment losses and impairment losses on investments.

(b) 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 excludes collateral funds deposited by counterparties of $106 million, $72 million, and $271 million as of December 31, 2015, 2014, and 2013, 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.

(c) Includes funded letter of credit in 2011.

(d) Includes debt issuance cost in 2015 and 2014.

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
			(In millions)		
Energy revenue	$ 6,592	$ 7,130	$ 5,636	$ 3,738	$ 3,804
Capacity revenue	2,178	2,109	1,860	765	750
Retail revenue	6,920	7,414	6,293	5,900	5,807
Mark-to-market for economic hedging activities	(255)	541	(542)	(418)	325
Contract amortization	(40)	(13)	(31)	(97)	(159)
Other revenues	570	611	413	260	342
Eliminations	(1,291)	(1,924)	(2,334)	(1,726)	(1,790)
Total operating revenues	$ 14,674	$ 15,868	$ 11,295	$ 8,422	$ 9,079

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, revenues from the sale of excess supply into various markets, primarily in Texas, as well as product sales.

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 2015 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, 2015, 2014, and 2013, 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 an integrated competitive power company, which 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 has one of the nation's largest and most diverse competitive generation portfolios balanced with the nation's largest competitive retail energy business. The Company owns and operates approximately 50,000 MW 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 names "NRG", "Reliant" and 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 2015 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 affect the prices derived in these auctions. These variables include the load forecast, the target reserve margin, rules surrounding demand response, capacity performance penalties, 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*. In addition, PJM integrated a new capacity performance construct into the market in 2015, as described in Item 1 — Business, *Regulatory Matters*.

Commodities Markets — 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 2015, average natural gas prices at Henry Hub were 40% lower than 2014.

If long-term gas prices further 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.

Natural gas prices are a primary driver of coal demand. The low priced commodity environment has stressed coal equities, leading coal suppliers to file for bankruptcy protection, launch debt exchanges, rationalize assets, and cut production. If multiple parties withdraw from the market, liquidity could be challenged in the short term. Inventory overhang will be utilized to offset production losses. Coal prices are typically affected by the price of natural gas.

Electricity Prices — The price of electricity is a key determinant of the profitability of the Company. 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 2015, electricity prices in the Company's core markets were lower than 2014 primarily due to lower natural gas prices. In 2014, electricity prices in the Company's core markets were generally higher than 2013 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, 2015, 2014, and 2013:

	Average on Peak Power Price ($/MWh)[(a)]		
Region	**2015**	**2014**	**2013**
Gulf Coast [(b)]			
ERCOT - Houston	$ 28.15	$ 43.73	$ 36.40
ERCOT - North	27.61	43.34	34.63
MISO - Louisiana Hub [(c)]	34.55	48.72	37.05
East			
NY J/NYC	46.42	71.72	62.94
NY A/West NY	42.07	58.16	46.57
NEPOOL	48.25	75.28	64.02
PEPCO (PJM)	46.48	70.69	47.14
PJM West Hub	41.97	61.15	43.89
West			
CAISO - NP15	35.50	49.27	41.63
CAISO - SP15	32.45	48.39	45.99

(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 price data is "into Entergy". MISO-Louisiana Hub began trading December 2013.

Environmental Regulatory Landscape — The MATS rule, finalized in 2012, is the primary regulatory force behind the decision to retrofit, repower or retire uncontrolled coal fired power plants. Companies are nearly done with their plans to comply as many units received a one-year extension until April 2016. In June 2015, the U.S. Supreme Court held that the EPA unreasonably refused to consider costs when it determined to regulate HAPs emitted by electric generating units. The U.S. Supreme Court did not vacate the MATS rule but rather remanded it to the D.C. Circuit for further proceedings. 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 and are under review by the courts. The design, timing and stringency of these regulations and the legal outcomes 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. In December 2015, the U.S. Congress enacted an extension of the 30% solar ITC so that projects which begin construction in 2016 through 2019 will continue to qualify for the 30% ITC. Projects beginning construction in 2020 and 2021 will be eligible for the ITC at the rates of 26% and 22% respectively. The same legislation also extended the 10 year wind PTC for wind projects which begin construction in years 2016 through 2019. Wind projects which begin construction in the years 2017, 2018 and 2019 are eligible for PTC at 80%, 60% and 40% of the statutory rate per kilowatt hour respectively.

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. Weather may also impact the availability of the Company's generating assets. 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 is also generally 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.

Wind and Solar Resource Availability — Wind and solar resource availability can affect the Company's results. The Company's results were impacted by lower than normal wind resource availability in 2015. While the Company's wind facilities were available, adverse weather had a negative impact on wind resources. The Company cannot predict wind and solar resource availability and their related impacts on future results.

Capital Market Conditions — The Company and its peer group, along with the broader energy sector, have recently experienced volatile conditions in the capital markets, including debt and equity markets, due to continued depressed commodity markets. These conditions, if they persist, may make it difficult for the Company, including GenOn and NRG Yield, Inc., to satisfy debt obligations which mature over the next few years at a reasonable cost. Further, NRG Yield, Inc.'s growth strategy depends on its ability to identify and acquire additional conventional and renewable facilities from the Company and unaffiliated third parties. A prolonged disruption in the equity capital market conditions could make it difficult for NRG Yield, Inc. to obtain the necessary financing to successfully acquire projects, which could impact a source of the Company's liquidity.

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, 2015, 2014 and 2013, 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, 2015

- *Impairment losses* — During 2015, the Company recognized impairment losses related to certain of its long-lived assets and goodwill for certain reporting units, as discussed in more detail in Item 15 — Note 10, *Asset Impairments*, and Note 11, *Goodwill and Other Intangibles*, to the Consolidated Financial Statements.

- *NRG Yield, Inc. equity and debt offerings* — During the second quarter of 2015, NRG Yield, Inc. completed its public offering of 28,198,000 shares of Class C common stock for net proceeds of $599 million. In addition, NRG Yield, Inc. issued $287.5 million aggregate principal amount of 3.25% Convertible Notes due 2020.

- *Debt Repurchases* — During the fourth quarter of 2015, the Company repurchased $520 million in aggregate principal of outstanding Senior Notes in the open market for $467 million, including accrued interest, as discussed in more detail in Item 15 - Note 12, *Debt and Capital Leases*, to the Consolidated Financial Statements.

- *Share Repurchases* — During 2015, under the 2015 Capital Allocation Program, the Company paid $437 million for the repurchase of 24,189,495 shares of common stock.

- *Transfers of Assets under Common Control* — 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 cash consideration of $489 million, including $9 million of working capital adjustments, plus assumed project level debt of $737 million.

  On November 3, 2015, the Company sold 75% of the Class B interests of NRG Wind TE Holdco, which owns a portfolio of 12 wind facilities totaling 814 net MW, to NRG Yield, Inc. NRG Yield Inc. paid total cash consideration of $209 million, subject to working capital adjustments. In February 2016, the Company made a final working capital payment of $2 million to NRG Yield, Inc., reducing total cash consideration to $207 million. NRG Yield, Inc. will be responsible for its pro-rata share of non-recourse project debt of $193 million and noncontrolling interest associated with a tax equity structure of $159 million (as of the acquisition date).

Significant events during the year ended December 31, 2014

- *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. public offering* — During the third quarter of 2014, NRG Yield, Inc. completed its second public offering of its Class A common shares for net proceeds of $630 million.

Subsequent Events

- *Sherwin Bankruptcy* — The Company's Gregory cogeneration plant provides steam, processed water and a small percentage of its electrical generation to the Corpus Christi Sherwin Alumina plant. On January 11, 2016, Sherwin Alumina Company, or Sherwin, filed a voluntary petition with the United States Bankruptcy Court for the Southern District of Texas for relief under Title 11 of the United States Code. Sherwin has agreed to pay all owed pre-petition amounts and, post-petition, Sherwin is performing pursuant to bankruptcy court authorization while it decides whether to reject the agreement Sherwin has with the Company's subsidiary that owns and operates the Company's Gregory cogeneration plant. Sherwin is seeking contractual concessions and could pursue a conversion to a Title 7 proceeding.

- *Canal 3 Development Project* — In February 2016, the Company's Canal 3 development project, a 333 MW gas turbine peaker which is scheduled to go online in 2019 on Cape Cod, cleared the ISO-NE tenth forward capacity auction at a price of $7.03/Kw-month.

Consolidated Results of Operations

2015 compared to 2014

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Year Ended December 31, 2015	2014[(a)]	Change %
Operating Revenues			
Energy revenue (b)	$ 5,494	$ 5,422	1 %
Capacity revenue (b)	2,164	2,087	4
Retail revenue	6,913	7,376	(6)
Mark-to-market for economic hedging activities	(244)	501	149
Contract amortization	(40)	(13)	(208)
Other revenues (c)	387	495	(22)
Total operating revenues	14,674	15,868	(8)
Operating Costs and Expenses			
Cost of sales (b)	7,838	8,623	(9)
Mark-to-market for economic hedging activities	128	488	74
Contract and emissions credit amortization (d)	11	31	(65)
Operations and maintenance	2,313	2,230	4
Other cost of operations	465	422	10
Total cost of operations	10,755	11,794	(9)
Depreciation and amortization	1,566	1,523	3
Impairment losses	5,030	97	N/M
Selling, general and administrative expense	1,220	1,027	19
Acquisition-related transaction and integration costs	10	84	(88)
Development costs	154	91	69
Total operating costs and expenses	18,735	14,616	28
Gain on post retirement benefits curtailment and sale of assets	21	19	11
Operating (Loss)/Income	(4,040)	1,271	(418)
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	36	38	(5)
Impairment losses on investments	(56)	—	N/A
Other income, net	33	22	50
(Loss)/gain on sale of equity-method investment	(14)	18	(178)
Net gain/(loss) on debt extinguishment	75	(95)	(179)
Interest expense	(1,128)	(1,119)	1
Total other expense	(1,054)	(1,136)	(7)
(Loss)/Income before income taxes	(5,094)	135	N/M
Income tax expense	1,342	3	N/M
Net (Loss)/Income	(6,436)	132	N/M
Less: Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	(54)	(2)	N/M
Net (loss)/income attributable to NRG Energy, Inc.	$ (6,382)	$ 134	N/M
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$ 2.66	$ 4.41	(40)%

(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
N/M- Not Meaningful

Management's discussion of the results of operations for the years ended December 31, 2015, and 2014

(Loss)/income before income tax expense — The pre-tax loss of $5,094 million for the year ended December 31, 2015, compared to pre-tax income of $135 million for the year ended December 31, 2014, primarily reflects:

- an increase of $4,989 million in impairment losses;
- a current year decrease from net mark-to-market results for economic hedges activity of $385 million;
- an increase of $448 million in other operating costs comprised primarily of depreciation and amortization, selling and marketing expense, general and administrative expense, acquisition-related transaction and integration costs and development costs;

partially offset by:

- an increase in economic gross margin of $455 million comprised of an increase in NRG Home Retail economic gross margin of $219 million, an increase in NRG Yield economic gross margin of $170 million, an increase in NRG Renew economic gross margin of $58 million, an increase in NRG Home Solar economic gross margin of $6 million, and an increase in NRG Business economic gross margin of $2 million;
- a decrease of $138 million in other expenses primarily relating to the gain on debt extinguishment.

Net (loss)/income — The decrease in net income of $6,568 million primarily reflects the drivers discussed above, including income tax expense for the year ended December 31, 2015, of $1,342 million, compared to income tax expense of $3 million for the year ended December 31, 2014, which reflects the valuation allowance recorded during the fourth quarter of 2015.

Economic gross margin

The Company evaluates its operating performance using the measure of economic gross margin, which is not a GAAP measure and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. The Company believes that economic gross margin is useful to investors as it is a key operational measure reviewed by the Company's chief operating decision maker. Economic gross margin is defined as the sum of energy revenue, capacity revenue, retail revenue and other revenue, less cost of sales.

Economic gross margin excludes the following elements from gross margin: mark-to-market gains or losses on economic hedging activities, contract amortization and emission credit amortization.

The following tables present the composition of economic gross margin, business metrics and weather metrics for the years ended December 31, 2015, and 2014:

	Year ended December 31, 2015											
	NRG Business						NRG Home					
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Eliminations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Eliminations/ Corporate	Total
Energy revenue	$ 2,548	$ 2,926	$ 269	$ —	$ —	$ 5,743	$ —	$ —	$ 444	$ 405	$ (1,098)	$ 5,494
Capacity revenue	291	1,345	195	6	—	1,837	—	—	—	341	(14)	2,164
Retail revenue	—	—	—	1,499	—	1,499	5,389	32	—	—	(7)	6,913
Other revenue	70	68	11	208	(59)	298	—	—	34	179	(124)	387
Operating revenue	2,909	4,339	475	1,713	(59)	9,377	5,389	32	478	925	(1,243)	14,958
Cost of fuel	(1,214)	(1,446)	(159)	—	—	(2,819)	(8)	—	(4)	(43)	62	(2,812)
Other costs of sales	(237)	(493)	(33)	(1,468)	—	(2,231)	(3,883)	(17)	(3)	(28)	1,136	(5,026)
Economic gross margin	$ 1,458	$ 2,400	$ 283	$ 245	$ (59)	$ 4,327	$ 1,498	$ 15	$ 471	$ 854	$ (45)	$ 7,120
Business Metrics												
MWh sold (thousands)[(a)(b)]	61,599	46,917	6,317						4,408	5,740		
MWh generated (thousands)[(c)]	57,679	46,289	4,542						4,461	8,227		
Electricity sales volume (GWh)				19,342								
Average customer count (thousands, metered locations)				82								

(a) MWh sold excludes generation at facilities that generate revenue under capacity agreements.
(b) Does not include MWh of 297 thousand or MWt of 1,946 thousand for thermal sold by NRG Yield.
(c) Does not include MWh of 205 thousand or MWt of 1,946 thousand for thermal generation by NRG Yield.

	Year ended December 31, 2014											
	NRG Business						NRG Home					
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Eliminations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Eliminations/ Corporate	Total
Energy revenue	$ 2,711	$ 3,439	$ 326	$ —	$ —	$ 6,476	$ —	$ —	$ 384	$ 270	$ (1,708)	$ 5,422
Capacity revenue	260	1,269	257	1	—	1,787	—	—	1	321	(22)	2,087
Retail revenue	—	—	—	1,870	—	1,870	5,502	42	—	—	(38)	7,376
Other revenue	86	107	8	189	(50)	340	—	—	39	182	(66)	495
Operating revenue	3,057	4,815	591	2,060	(50)	10,473	5,502	42	424	773	(1,834)	15,380
Cost of fuel	(1,494)	(1,841)	(235)	—	—	(3,570)	(16)	—	(4)	(62)	75	(3,577)
Other costs of sales	(293)	(413)	(31)	(1,832)	—	(2,569)	(4,207)	(33)	(7)	(27)	1,797	(5,046)
Economic gross margin	$ 1,270	$ 2,561	$ 325	$ 228	$ (50)	$ 4,334	$ 1,279	$ 9	$ 413	$ 684	$ 38	$ 6,757
Business Metrics												
MWh sold (thousands)[(a)(b)]	63,860	49,619	4,769						4,026	3,977		
MWh generated (thousands)[(c)]	59,872	51,191	4,241						4,026	6,108		
Electricity sales volume (GWh)				21,816								
Average customer count (thousands, metered locations)				82								

(a) MWh sold excludes generation at facilities that generate revenue under capacity agreements.
(b) Does not include MWh of 205 thousand or MWt of 2,060 thousand for thermal sold by NRG Yield.
(c) Does not include MWh of 224 thousand or MWt of 2,060 thousand for thermal generation by NRG Yield.

Weather Metrics	Years ended December 31, Gulf Coast [(b)]	East	West
2015			
CDDs [(a)]	2,870	1,336	1,111
HDDs [(a)]	1,887	4,697	1,948
2014			
CDDs	2,737	1,068	1,158
HDDs	2,157	5,123	1,712
10 year average			
CDDs	2,901	1,188	821
HDDs	1,900	4,712	2,404

(a) 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.

(b) 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 economic gross margin

NRG Business economic gross margin increased by $2 million, including intercompany sales, during the year ended December 31, 2015, compared to the same period in 2014, due to:

	(In millions)
Increase in Gulf Coast region	$ 188
Decrease in East region	(161)
Decrease in West region	(42)
Increase in B2B	17
	$ 2

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

	(In millions)
Higher gross margin, which reflects a decrease in ERCOT merchant power prices, offset by the impact of beneficial hedges, as well as a decrease in natural gas prices	$ 174
Higher gross margin due to an increase in capacity revenue from higher pricing for certain South Central facilities as well as an increase in average realized prices which reflects the impact of beneficial hedges	139
Higher gross margin from an increase in gas generation in Texas, which reflects lower supply costs from lower natural gas prices	28
Lower gross margin due to lower coal generation in Texas, which was driven by lower natural gas prices	(71)
Lower capacity revenue due to the expiration of contracts in Texas and South Central	(49)
Lower coal gross margin due to lower coal generation in South Central, primarily for the conversion of Big Cajun Unit 2 to gas	(32)
Lower gross margin from decrease in nuclear generation driven by increased planned and unplanned outages	(21)
Changes in commercial optimization and other	20
	$ 188

The decrease in economic gross margin in the East region was driven by:

		(In millions)
Lower gross margin due to a 27% decrease in coal generation as a result of prior year winter weather conditions and plant deactivations	$	(324)
Lower gross margin driven by a 7% decrease in PJM cleared auction capacity volumes primarily from unit deactivations, coupled with increased purchased capacity, partially offset by a 4% increase in PJM cleared auction capacity prices		(60)
Changes in commercial optimization activities		(34)
Lower gross margin due to market adjustments for fuel oil inventory		(8)
Higher gross margin due to the EME acquisition in April 2014		121
Higher gross margin for gas facilities due to a decrease in natural gas prices, partially offset by a 6% decrease in average realized energy prices, which reflect the impact of beneficial hedges		55
Higher gross margin due to new load contracts starting in June 2014 and lower supply cost		50
Higher gross margin primarily driven by a 9% increase in New York and New England hedged capacity prices offset by purchased capacity		29
Other		10
	$	(161)

The decrease in economic gross margin in the West region was driven by:

		(In millions)
Lower capacity gross margin due to a 17% decrease in price as a result of higher reserve margins driven by more competition in certain areas and the expiration of certain tolling arrangements, which were replaced with lower priced agreements	$	(43)
Lower gross margin due to the retirement of Coolwater		(21)
Higher energy gross margin due to a 15% increase in volume driven by more available generation resulting from the expiration of certain tolling arrangements and a 39% decrease in gas prices, partially offset by a 27% decrease in energy prices		11
Higher gross margin due to the EME acquisition		8
Other		3
	$	(42)

The increase in B2B economic gross margin was driven by:

		(In millions)
Higher gross margin for the C&I business in 2015 due to higher supply costs incurred in early 2014 as a result of prior year winter weather conditions and lower supply costs in 2015 driven by lower natural gas prices	$	17
Higher margin for the energy services business due to new contracts and new business		4
Lower gross margin from a decrease in customer usage due to customer mix		(3)
Other		(1)
	$	17

NRG Home Retail economic gross margin

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

Selected Income Statement Data

(In millions except otherwise noted)	Years ended December 31, 2015	2014
Home Retail revenue	$ 5,251	$ 5,269
Supply management revenue	138	233
Operating revenues [(a)]	$ 5,389	$ 5,502
Cost of sales [(b)]	(3,891)	(4,223)
Economic gross margin	$ 1,498	$ 1,279
Business Metrics		
Electricity sales volume (GWh) - Gulf Coast	34,600	33,284
Electricity sales volume (GWh) - All other regions	8,090	8,218
Average NRG Home Retail customer count (in thousands) [(c)]	2,783	2,718
NRG Home Retail customer count (in thousands) [(c)]	2,766	2,844

(a) Includes intercompany sales of $8 million and $9 million, respectively.
(b) Includes intercompany purchases of $1,054 million and $1,846 million, respectively.
(c) Excludes Discrete customers.

NRG Home Retail economic gross margin increased $219 million for the year ended December 31, 2015, compared to the same period in 2014, driven by:

	(In millions)
Higher gross margin due to lower supply costs partially offset by lower rates to customers driven by a decrease in natural gas prices	$ 172
Higher gross margin due to lower supply costs on the higher sales volumes resulting from weather in 2015	50
Other	(3)
	$ 219

NRG Home Solar economic gross margin

NRG Home Solar economic gross margin increased by $6 million for the year ended December 31, 2015, compared to the same period in 2014, which was primarily related to an increase in solar leases deployed.

NRG Renew economic gross margin

NRG Renew economic gross margin increased $58 million for the year ended December 31, 2015, compared to the same period in 2014. The increase in gross margin was a result of the EME acquisition in April 2014 and improved performance at the Ivanpah project, as it continues towards full production capabilities.

NRG Yield economic gross margin

NRG Yield economic gross margin increased $170 million for the year ended December 31, 2015, compared to the same period in 2014. The increase in gross margin was primarily related to the acquisition of the Alta Wind Assets in August 2014 as well as the acquisition of the January 2015 Drop Down Assets and the November 2015 Drop Down Assets from NRG, the majority of which were acquired by NRG from EME in April 2014.

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 $385 million during the year ended December 31, 2015, compared to the same period in 2014.

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, 2015								
		NRG Business							
	NRG Home	Gulf Coast	East	West	B2B	NRG Renew	NRG Yield	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	$ —	$ (408)	$ (288)	$ 6	$ (1)	$ (3)	$ (2)	$ (46)	$ (742)
Reversal of acquired gain positions related to economic hedges	—	—	(84)	—	—	—	—	—	(84)
Net unrealized gains on open positions related to economic hedges	—	342	174	4	5	—	—	57	582
Total mark-to-market (losses)/gains in operating revenues	$ —	$ (66)	$ (198)	$ 10	$ 4	$ (3)	$ (2)	$ 11	$ (244)
Mark-to-market results in operating costs and expenses									
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 256	$ 34	$ 15	$ (1)	$ 117	$ —	$ —	$ 46	$ 467
Reversal of acquired gain positions related to economic hedges	(3)	—	—	(18)	(1)	—	—	—	(22)
Net unrealized (losses)/gains on open positions related to economic hedges	(192)	(51)	(93)	1	(181)	—	—	(57)	(573)
Total mark-to-market gains/(losses) in operating costs and expenses	$ 61	$ (17)	$ (78)	$ (18)	$ (65)	$ —	$ —	$ (11)	$ (128)

(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, 2015, the $244 million loss in operating revenues from economic hedge positions was driven primarily by the reversal of previously recognized unrealized gains on contracts that settled during the period and the reversal of acquired contracts largely offset by an increase in value of open positions as a result of decreases in ERCOT and PJM electricity prices. The $128 million loss in operating costs and expenses from economic hedge positions was driven primarily by a decrease in the value of open positions as a result of decreases in ERCOT electricity and coal prices and the reversal of acquired contracts, largely offset by the reversal of previously recognized unrealized losses on contracts that settled during the period.

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, 2015, and 2014. 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)	**2015**	**2014**
Trading gains/(losses)		
Realized	$ 57	$ 136
Unrealized	(76)	14
Total trading (losses)/gains	$ (19)	$ 150

Operations and maintenance expense

	NRG Business				NRG Home Retail	NRG Home Solar	NRG Renew	NRG Yield	Eliminations	Total
	Gulf Coast	East	West	B2B						
	(In millions)									
Year Ended December 31, 2015	$ 643	$ 1,006	$ 143	$ 81	$ 201	$ 18	$ 135	$ 171	$ (85)	$ 2,313
Year Ended December 31, 2014	617	1,017	141	84	197	11	116	131	(84)	2,230

Operations and maintenance expenses increased by $83 million for the year ended December 31, 2015, compared to the same period in 2014, due to:

	(In millions)
Increase due to the acquisition of EME in April 2014 and the Alta Wind Assets in August 2014	$ 116
Increase in operations and maintenance expense related to planned outages at Cottonwood and Big Cajun	42
Increase in operations and maintenance expense related to Ivanpah reaching commercial operations in early 2014	8
Increase in operations and maintenance expense related to El Segundo Energy Center's forced outage in 2015	6
Increase due to the acquisition of Dominion in March 2014	4
Decrease in East operations and maintenance expense related to the timing and expense for prior year outages at various plants	(64)
Decrease in operations and maintenance expense due to the retirement of Coolwater	(30)
Decrease in operations and maintenance expense related to Texas coal facilities due to timing of outages	(14)
Other	15
	$ 83

Other cost of operations

Other cost of operations, comprised of asset retirement expense, insurance expense and property tax expense, increased by $43 million for the year ended December 31, 2015, compared to the same period in 2014, primarily due to the increase in property tax expense related to the acquisition of EME in April 2014 and the Alta Wind Assets in August 2014.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $43 million for the year ended December 31, 2015, compared to the same period in 2014, primarily due to increases of $19 million and $40 million due to the acquisitions of EME in April 2014 and the Alta Wind Assets in August 2014, respectively, partially offset by a decrease in depreciation expense for facilities impaired during 2015.

Impairment Losses

In 2015, the Company recorded impairment losses of $5,030 million related to various facilities, as well as goodwill for its Texas and Home Solar reporting units, as further described in Item 15 — Note 10, *Asset Impairments*, and Note 11, *Goodwill and Other Intangibles*, to the Consolidated Financial Statements.

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

Selling, Marketing, General and Administrative Expenses

Selling, marketing, general and administrative expenses are comprised of the following:

	For the year ended December 31,	
(In millions)	**2015**	**2014**
Selling and marketing expense	$ 509	$ 343
General and administrative expenses	711	684
	$ 1,220	$ 1,027

Selling and marketing expenses increased $166 million for the year ended December 31, 2015 compared to the same period in 2014, due primarily to an increase in expense related to retail acquisitions as well as channel and product expansions in the core retail business, which also contributed to margin expansion during the same time period. The increase was also driven by Home Solar acquisitions in 2014, which provided NRG Home Solar with an installation team, a sales team and additional sales channels.

General and administrative expenses increased by $27 million for the year ended December 31, 2015, compared to the same period in 2014, due primarily to expansion of the Home Solar business partially offset by continued integration and cost management efforts.

Acquisition-related Transaction and Integration Costs

NRG incurred transaction and integration costs of $10 million for the year ended December 31, 2015, compared to $84 million for the same period in 2014. The reduction in transaction and integration costs is due primarily to the substantial completion of integration activities for the acquisitions of Alta Wind, Dominion and EME in 2014.

Development Costs

NRG incurred development costs of $154 million for the year ended December 31, 2015, compared to $91 million for the same period in 2014. The increase in development costs is due to increased development activities, primarily for Renewables and NRG eVgo.

Equity in Earnings of Unconsolidated Affiliates

NRG's equity in earnings of unconsolidated affiliates was $36 million for the year ended December 31, 2015, compared to $38 million for the same period in 2014, due primarily to lower income at Watson, Midway Sunset, and Saguaro, partially offset by NRG Yield, Inc.'s acquisition of Desert Sunlight.

Impairment Losses on Investments

In 2015, the Company recorded other-than-temporary impairment losses on certain of its cost and equity-method investments of $56 million, as further described in Item 15 — Note 10, *Asset Impairments*, to the Consolidated Financial Statements.

(Loss)/Gain on Sale of Equity Method Investment

In the fourth quarter of 2015, the Company sold its 32% interest in Altenex, as described in Item 15 — Note 3, *Business Acquisitions and Dispositions*, to the Consolidated Financial Statements. In connection with the sale the Company received cash proceeds of $26 million and recorded a loss on the sale of $14 million.

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

Gain/(Loss) on Debt Extinguishment

A gain on debt extinguishment of $75 million was recorded for the year ended December 31, 2015, primarily driven by the repurchase of NRG senior notes due 2023 and 2024, GenOn senior notes due 2020, and GenOn Americas Generation senior notes due 2021 and 2031 at a price below par value, combined with the write-off of unamortized premium. The repurchase of senior notes during 2015 will result in future interest savings of approximately $42 million annually.

In the fourth quarter of 2014, a loss of $95 million was recorded primarily due to the redemption premiums from the redemption of the 2019 Senior Notes. These gains/losses also included the write-off of previously deferred financing costs.

Interest Expense

NRG's interest expense increased by $9 million for the year ended December 31, 2015, compared to the same period in 2014 due to the following:

	(In millions)
Increase due to the acquisition of EME in April 2014 and Alta Wind in August 2014	$ 51
Increase for the 2022 Senior Notes issued in January 2014 and the 2024 Senior Notes issued in April 2014	24
Increase due to issuance of the NRG Yield Operating LLC 2024 Senior Notes issued in 2014	17
Decrease in derivative interest expense primarily from changes in fair value of interest rate swaps	(40)
Decrease due to the redemption of 7.625% and 8.5% Senior Notes due 2019	(38)
Other	(5)
	$ 9

Income Tax Expense

For the year ended December 31, 2015, NRG recorded income tax expense of $1,342 million on a pre-tax loss of $5,094 million. For the same period in 2014, NRG recorded an income tax expense of $3 million on pre-tax income of $135 million. The effective tax rate was (26.3)% and 2.2% for the years ended December 31, 2015, and 2014, respectively.

For the year ended December 31, 2015, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to recording of a valuation allowance on the federal and certain state net deferred tax assets that may not be realizable under a “more likely than not” measurement. In addition, a portion of the book goodwill impairment is classified as a permanent reversal impacting the effective tax rate.

	Year Ended December 31,	
	2015	2014
	(In millions except as otherwise stated)	
(Loss)/Income Before Income Taxes	$ (5,094)	$ 135
Tax at 35%	(1,783)	47
State taxes	(218)	9
Foreign operations	1	1
Federal and state tax credits, excluding PTCs	(5)	(1)
Valuation allowance	3,039	6
Book goodwill impairment	340	—
Impact of non-taxable entity earnings	(10)	(11)
Net interest accrued on uncertain tax positions	(3)	(2)
Production tax credits	(33)	(48)
Recognition of uncertain tax benefits	(15)	(30)
Tax expense attributable to consolidated partnerships	12	4
Impact of change in effective state tax rate	19	22
Other	(2)	6
Income tax expense	$ 1,342	$ 3
Effective income tax rate	(26.3)%	2.2%

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 attributable to noncontrolling interests and redeemable noncontrolling interests

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests was $54 million for the year ended December 31, 2015, compared to $2 million for the year ended December 31, 2014. For the years ended December 31, 2015, and 2014, the net losses attributable to noncontrolling interests primarily reflect losses allocated to tax equity investors using the hypothetical liquidation at book value, or HLBV, method, offset in part by NRG Yield, Inc.'s share of net income for the period.

Consolidated Results of Operations

2014 compared to 2013

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Year Ended December 31, 2014[(a)]	Year Ended December 31, 2013	Change %
Operating Revenues			
Energy revenue [(b)]	$ 5,422	$ 3,530	54%
Capacity revenue [(b)]	2,087	1,800	16
Retail revenue	7,376	6,287	17
Mark-to-market for economic hedging activities	501	(578)	187
Contract amortization	(13)	(31)	58
Other revenues [(c)]	495	287	72
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)
Operations and maintenance	2,230	1,789	25
Other cost of operations	422	329	28
Total cost of operations	11,794	8,130	45
Depreciation and amortization	1,523	1,256	21
Impairment losses	97	459	(79)
Selling, general and administrative expense	1,027	895	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)	N/A
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 tax expense	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.
N/A - Not Applicable

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

Economic gross margin

The Company evaluates its operating performance using the measure of economic gross margin, which is not a GAAP measure and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. The Company believes that economic gross margin is useful to investors as it is a key operational measure reviewed by the Company's chief operating decision maker. Economic gross margin is defined as the sum of energy revenue, capacity revenue, retail revenue and other revenue, less cost of sales.

Economic gross margin excludes the following elements from gross margin: mark-to-market gains or losses on economic hedging activities, contract amortization and emission credit amortization.

The following tables present the composition of economic gross margin, business metrics and weather metrics for the years ended December 31, 2014, and 2013:

	Year ended December 31, 2014											
	NRG Business						NRG Home					
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Eliminations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Eliminations/ Corporate	Total
Energy revenue	$ 2,711	$ 3,439	$ 326	$ —	$ —	$ 6,476	$ —	$ —	$ 384	$ 270	$ (1,708)	$ 5,422
Capacity revenue	260	1,269	257	1	—	1,787	—	—	1	321	(22)	2,087
Retail revenue	—	—	—	1,870	—	1,870	5,502	42	—	—	(38)	7,376
Other revenue	86	107	8	189	(50)	340	—	—	39	182	(66)	495
Operating revenue	3,057	4,815	591	2,060	(50)	10,473	5,502	42	424	773	(1,834)	15,380
Cost of fuels	(1,494)	(1,841)	(235)	—	—	(3,570)	(16)	—	(4)	(62)	75	(3,577)
Other costs of sales	(293)	(413)	(31)	(1,832)	—	(2,569)	(4,207)	(33)	(7)	(27)	1,797	(5,046)
Economic gross margin	$ 1,270	$ 2,561	$ 325	$ 228	$ (50)	$ 4,334	$ 1,279	$ 9	$ 413	$ 684	$ 38	$ 6,757
Business Metrics												
MWh sold (thousands)(a)(b)	63,860	49,619	4,769						4,026	3,977		
MWh generated (thousands)(c)	59,872	51,191	4,241						4,026	6,108		
Electricity sales volume (GWh)				21,816								
Average customer count (thousands, metered locations)				82								

(a) MWh sold excludes generation at facilities that generate revenue under capacity agreements.
(b) Does not include MWh of 205 thousand or MWt of 2,060 thousand for thermal sold by NRG Yield.
(c) Does not include MWh of 224 thousand or MWt of 2,060 thousand for thermal generation by NRG Yield.

	Year ended December 31, 2013											
	NRG Business						NRG Home					
(In millions except otherwise noted)	Gulf Coast	East	West	B2B	Elimination s	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Eliminations/ Corporate	Total
Energy revenue	$ 2,748	$ 2,439	$ 148	$ —	$ —	$ 5,335	$ —	$ —	$ 190	$ 111	$ (2,106)	$ 3,530
Capacity revenue	372	1,075	265	8	—	1,720	—	—	—	140	(60)	1,800
Retail revenue	—	—	—	1,909	—	1,909	4,384	—	—	—	(6)	6,287
Other revenue	26	78	4	132	(46)	194	7	4	25	137	(80)	287
Operating revenue	3,146	3,592	417	2,049	(46)	9,158	4,391	4	215	388	(2,252)	11,904
Cost of fuels	(1,362)	(1,351)	(101)	(1)	—	(2,815)	(13)	—	—	(42)	91	(2,779)
Other costs of sales	(413)	(179)	(13)	(1,800)	—	(2,405)	(3,206)	—	(8)	(26)	2,152	(3,493)
Economic gross margin	$ 1,371	$ 2,062	$ 303	$ 248	$ (46)	$ 3,938	$ 1,172	$ 4	$ 207	$ 320	$ (9)	$ 5,632
Business Metrics												
MWh sold (thousands)(a)(b)	63,643	34,888	1,534						1,687	1,221		
MWh generated (thousands)(c)	57,193	34,081	2,876						1,687	1,973		
Electricity sales volume (GWh)				25,748								
Average customer count (thousands, metered locations)				99								

(a) MWh sold excludes generation at facilities that generate revenue under capacity agreements.
(b) Does not include MWh of 139 thousand or MWt of 1,679 thousand for thermal sold by NRG Yield.
(c) Does not include MWh of 139 thousand or MWt of 1,858 thousand for thermal generated by NRG Yield.

Weather Metrics	Year Ended December 31,		
	Gulf Coast [b]	East	West
2014			
CDDs [a]	2,737	1,068	1,158
HDDs [a]	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

(a) 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.

(b) 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 economic gross margin

NRG Business economic gross margin increased by $400 million, including intercompany sales, during the year ended December 31, 2014, compared to the same period in 2013, due to:

		(In millions)
Decrease in Gulf Coast region	$	(101)
Increase in East region		499
Increase in West region		22
Decrease in B2B		(20)
	$	400

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

		(In millions)
Lower gross margin which reflects an increase in ERCOT merchant power prices, offset by the negative impact of hedges, 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		9
	$	(101)

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

		(In millions)
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)
Change in commercial optimization activities and other		33
	$	499

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

		(In millions)
Higher gross margin due to the EME acquisition in April 2014	$	28
Higher capacity gross margin due to increase in realized prices		29
Lower gross margin due to the deactivation of the Contra Costa facility in 2013 and other changes in contracted assets		(23)
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)
Other		5
	$	22

The decrease in B2B economic gross margin was driven by:

		(In millions)
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		2
	$	(20)

NRG Home Retail economic gross margin

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

Selected Income Statement Data

	Years ended December 31,	
(In millions except otherwise noted)	**2014**	**2013**
Home Retail revenue [(a)]	$ 5,269	$ 4,257
Supply management revenue	233	134
Operating revenues	$ 5,502	$ 4,391
Cost of sales [(b)]	(4,223)	(3,219)
Economic gross margin	$ 1,279	$ 1,172
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) [(c)]	2,718	2,190
NRG Home customer count (in thousands) [(c)]	2,844	2,217

(a) Includes intercompany sales of $9 million and $9 million, respectively

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

(c) Excludes Discrete customers.

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

	(In millions)
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

NRG Home Solar economic gross margin

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

NRG Renew economic gross margin

NRG Renew had economic gross margin of $413 million for the year ended December 31, 2014, compared to $207 million for the same period in 2013. The increase in economic gross margin was primarily the result of $102 million related to the CVSR and Ivanpah projects which reached commercial operations in late 2013 and early 2014, respectively, and $70 million related to the projects within the Renew segment that were acquired in the EME acquisition in April 2014.

NRG Yield economic gross margin

NRG Yield had economic gross margin of $684 million for the year ended December 31, 2014, compared to economic gross margin of $320 million for the same period in 2013. The increase was primarily due to $162 million from the acquisition of the January 2015 Drop Down Assets and the November 2015 Drop Down Assets, which were primarily acquired by NRG in April 2014, $109 million from Marsh Landing and El Segundo Energy Center, which both reached commercial operations in 2013, $64 million from the acquisition of the Alta Wind Assets in August 2014 and $15 million from the acquisition of Energy Systems Company in December 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 in 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 are as follows:

	Year Ended December 31, 2014								
		NRG Business							
	NRG Home	Gulf Coast	East	West	B2B	NRG Renew	NRG Yield	Elimination[(a)]	Total
	(In millions)								
Mark-to-market results in operating revenues									
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ —	$ (6)	$ 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)	—	3	2	(39)	826
Total mark-to-market gains/ (losses) in operating revenues	$ —	$ 504	$ 42	$ (11)	$ —	$ 4	$ 2	$ (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 primarily 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 driven primarily from 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 years ended December 31, 2014, and 2013. 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. Beginning in April 2014, the Company's trading activities were primarily transacted through BETM.

	Year Ended December 31, 2014	Year Ended December 31, 2013
	(In millions)	
Trading gains/(losses)		
Realized	$ 136	$ 66
Unrealized	14	(43)
Total trading gains	$ 150	$ 23

Operations and maintenance expense

	NRG Business Gulf Coast	East	West	B2B	NRG Home Retail	NRG Home Solar	NRG Renew	NRG Yield	Eliminations	Total
	(In millions)									
Year Ended December 31, 2014	$ 617	$ 1,017	$ 141	$ 84	$ 197	$ 11	$ 116	$ 131	$ (84)	$ 2,230
Year Ended December 31, 2013	569	809	150	69	160	—	30	66	(64)	1,789

Operations and maintenance expenses increased by $441 million for the year ended December 31, 2014, compared to the same period in 2013, due to:

	(In millions)
Increase due to the acquisition of EME in April 2014	$ 310
Increase for CVSR and Ivanpah projects which reached commercial operations in late 2013 and early 2014	78
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 W.A. Parish and Limestone coal plants in Texas	60
Increase due to the acquisition of the Alta Wind Assets and Energy Systems Company	17
Increase in operations and maintenance expense as Marsh Landing, El Segundo, and other smaller projects reached commercial operations in 2013	15
Decrease in operations and maintenance expense for significant outages in 2013 at Morgantown, Seward, and Cheswick which did not recur in 2014, lower plant deactivation costs for Titus and sale of Kendall	(49)
Other	10
	$ 441

Other cost of operations

Other cost of operations, comprised of asset retirement expense, insurance expense, and property tax expense, increased by $93 million for the year ended December 31, 2014, compared to the same period in 2013 due to increased expenses related various projects reaching commercial operations in late 2013 and early 2014, as well as an increase in property tax expense related to the acquisition of EME in April 2014 and the Alta Wind Assets in August 2014.

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, 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*, to the Consolidated Financial Statements.

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*, to the Consolidated Financial Statements.

Selling, Marketing, General and Administrative Expenses

Selling, marketing, general and administrative expenses are comprised of the following:

	For the year ended December 31,	
(In millions)	**2014**	**2013**
Selling and marketing expense	$ 343	$ 312
General and administrative expenses	684	583
	$ 1,027	$ 895

Selling and marketing expense increased $31 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 $101 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 substantial completion of the GenOn integration activities in 2013, offset by the acquisitions and integration costs 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. This increase in development costs relates primarily to an increase in Renewable 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. The increase was due primarily to $13 million of income in 2014 from a long-term natural gas hedge entered into by Saguaro in July 2013 compared to losses of $11 million in 2013, 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*, to the Consolidated Financial Statements. In connection with the sale, the Company received cash proceeds of $35 million and recorded a gain on 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:

	(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
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 NRG Yield 2019 Convertible Notes and Senior Notes in February and August 2014	23
Increase in amortization of premium/discount	14
Decrease for 7.625% and 8.5% Senior Notes due 2019 redeemed in the first, second and third quarters of 2014	(76)
Decrease for 7.625% GenOn Senior Notes due 2014 redeemed in June 2013	(21)
	$ 271

Income Tax Expense/(Benefit)

For the year ended December 31, 2014, NRG recorded an 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 tax 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. 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 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 2014, 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 using the HLBV method.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2015 and 2014, NRG's liquidity, excluding collateral funds deposited by counterparties, was approximately $3.3 billion and $3.9 billion, respectively, comprised of the following:

	As of December 31,	
	2015	2014
	(In millions)	
Cash and cash equivalents:		
NRG excluding NRG Yield and GenOn	$ 742	$ 767
NRG Yield and subsidiaries	111	429
GenOn and subsidiaries	665	920
Restricted cash - operating	127	203
Restricted cash - reserves [(a)]	287	254
Total	1,932	2,573
Total credit facility availability	1,373	1,367
Total liquidity, excluding collateral funds deposited by counterparties	$ 3,305	$ 3,940

(a) Includes reserves primarily for debt service, performance obligations, and capital expenditures

For the year ended December 31, 2015, total liquidity, excluding collateral funds deposited by counterparties, decreased by $635 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, 2015, 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 $1.5 billion of cash and cash equivalents of the Company as of December 31, 2015, $299 million and $192 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, 2015, 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, 2015, GenOn did not meet the consolidated debt ratio component of the restricted payments test.

As disclosed in Item 15 — Note 12, *Debt and Capital Leases*, to the Consolidated Financial Statements, certain of GenOn's senior unsecured notes mature in 2017 and 2018. If GenOn is not able to refinance these notes prior to their maturities, it may have an adverse impact on GenOn's financial position. GenOn will consider all options available to it, including refinancing the notes, potential sales of certain generating assets or issuances of new debt securities. Given current economic and market conditions, including the depressed commodity markets, GenOn may be unable to complete these actions on a timely basis or on satisfactory terms or at all. These actions also may not be sufficient to enable GenOn to continue to satisfy its related cash commitments as they become due.

GenOn's financial position continues to be adversely affected by a sustained decline in natural gas prices and its resulting effect on wholesale power prices. In addition, GenOn Mid-Atlantic and REMA are currently unable to make distributions of cash and certain other restricted payments to GenOn. If gas and power prices remain depressed, GenOn may be unable to generate sufficient cash flow from operations to meets its long-term liquidity requirements, including operating, maintenance and capital expenditures and debt service 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.

On October 2, 2015, Standard & Poor's, or S&P, lowered its corporate credit ratings on GenOn, GenOn Mid-Atlantic, REMA and GenOn Americas Generation to CCC+ from B-. The ratings outlook for GenOn, GenOn Mid-Atlantic, REMA and GenOn Americas Generation is stable. S&P also lowered the issue ratings on the GenOn senior notes, the pass-through certificates at GenOn Mid-Atlantic and the GenOn Americas Generation senior notes to B- from B. The issue rating on the pass-through certificates of REMA was lowered by S&P to B from B+.

On September 18, 2015, S&P reaffirmed its corporate credit ratings on NRG Yield, Inc. and the Senior Notes due 2024. The rating outlook is stable. On October 6, 2015, Moody's lowered its corporate credit ratings on NRG Yield, Inc. and the NRG Yield Operating LLC Senior Notes due 2024 to Ba2 from Ba1, respectively. The rating outlook is stable.

On October 21, 2015, S&P reaffirmed its corporate credit ratings on NRG Energy, Inc. and its secured and unsecured debt.

The following table summarizes the credit ratings as of December 31, 2015:

	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	Ba2 Stable
5.375% NRG Yield Operating LLC Senior Notes, due 2024	BB+	Ba2

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 future sales of assets to NRG Yield, Inc. As described in Item 15 — Note 12, *Debt and Capital Leases,* to the Consolidated Financial Statements, the Company's financing arrangements consist mainly of the Senior Credit Facility, the Senior Notes, the GenOn Senior Notes, the GenOn Americas Generation Senior Notes, the NRG Yield 2019 Convertible Notes, the NRG Yield 2020 Convertible Notes, the Yield Operating senior unsecured notes, the NRG Yield, Inc. revolving credit facility, and project-related financings.

The Company is currently executing several cost reduction initiatives including: (i) planned annual cost savings of $150 million through the streamlining of administrative, marketing and development functions in 2016; (ii) an annual cost reduction of $100 million associated with the Company's operations and maintenance spend in 2016; and (iii) a reduction in NRG's capital expenditure program of approximately $100 million through the elimination of certain fuel conversion projects at GenOn plants.

Cash Proceeds from NRG Yield, Inc. Class C Common Stock and Convertible Notes

On June 29, 2015, NRG Yield, Inc. issued 28,198,000 shares of its Class C common stock for net proceeds of $599 million and closed on its offering of $287.5 million aggregate principal amount of 3.25% Convertible Senior Notes due 2020, or the NRG Yield 2020 Convertible Notes. The NRG Yield 2020 Convertible Notes are convertible, under certain circumstances, into NRG Yield, Inc. Class C common stock, cash or a combination thereof at an initial conversion price of $27.50 per Class C common share, which is equivalent to an initial conversion rate of approximately 36.3636 shares of Class C common stock per $1,000 principal amount of notes. The proceeds from the Class C Common Stock and the NRG Yield 2020 Convertible Notes issuances were used to fund the purchase of 25% of the membership interest in Desert Sunlight Investment Holdings, LLC and to repay all of the outstanding project indebtedness associated with the Alta X and Alta XI wind facilities.

Cash Proceeds from Sale of Assets to NRG Yield, Inc.

On November 3, 2015, the Company sold 75% of the Class B interests of NRG Wind TE Holdco, which owns a portfolio of twelve wind facilities totaling 814 net MW, to NRG Yield, Inc. for total cash consideration of $209 million, subject to working capital adjustments. NRG Yield, Inc. is responsible for its pro-rata share of non-recourse project debt of $193 million and noncontrolling interest associated with a tax equity structure of $159 million (as of the acquisition date). In February 2016, the Company made a final working capital payment of $2 million to NRG Yield, Inc. reducing total cash consideration to $207 million.

The sale was recorded as a transfer of entities under common control and the related assets were transferred at carrying value. NRG Yield, Inc. utilized borrowings under its revolving credit facility to fund the acquisition.

On January 2, 2015, the Company sold the following facilities to NRG Yield, Inc.: (i) Walnut Creek, a 485 MW natural gas facility located in City of Industry, California; (ii) the Tapestry projects, which include Buffalo Bear, a 19 MW wind facility in Buffalo, Oklahoma; Pinnacle, a 55 MW wind facility in Keyser, West Virginia; and Taloga, a 130 MW wind facility in Putnam, Oklahoma; and (iii) Laredo Ridge, an 80 MW wind facility located in Petersburg, Nebraska. NRG Yield, Inc. paid total cash consideration of $489 million, including $9 million of working capital adjustments, plus assumed project level debt of $737 million. The sale was recorded as a transfer of entities under common control and the related assets were transferred at carrying value. NRG Yield, Inc. utilized cash on hand and borrowings of $210 million under its revolving credit facility to fund the acquisition.

ROFO Assets

The Company entered into the ROFO Agreement with NRG Yield, Inc., under which the Company has granted NRG Yield, Inc. and its affiliates a right of first offer on any proposed sale, transfer or other disposition of certain assets of the Company for a period of seven years from May 14, 2015. In addition to the assets described in the table below, which reflects the remaining assets subject to sale, the ROFO Agreement also provides NRG Yield, Inc. with a right of first offer with respect to up to $250 million of equity in one or more residential or distributed solar generation portfolios developed by affiliates of the Company.

Asset	Fuel Type	Rated Capacity (MW)[(a)]	COD
CVSR[(b)]	Solar	128	2013
Ivanpah[(c)]	Solar	193	2013
Agua Caliente[(d)]	Solar	148	2014
Carlsbad	Conventional	527	2018
Puente/Mandalay	Conventional	262	2020
TE Wind Holdco[(e)]:			
Elkhorn Ridge	Wind	13	2009
San Juan Mesa	Wind	22	2005
Wildorado	Wind	40	2007
Crosswinds	Wind	5	2007
Forward	Wind	7	2008
Hardin	Wind	4	2007
Odin	Wind	5	2007
Sleeping Bear	Wind	24	2007
Spanish Fork	Wind	5	2008
Goat Wind	Wind	37	2008/2009
Lookout	Wind	9	2008
Elbow Creek	Wind	30	2008
Community	Wind	30	2011
Jeffers	Wind	50	2008
Minnesota Portfolio[(f)]	Wind	40	2003/2006

(a) Represents the maximum, or rated, electricity generating capacity of the facility in MW multiplied by the Company's percentage ownership interest in the facility as of December 31, 2015.

(b) Represents the Company's remaining 51.05% ownership interest in CVSR.

(c) Represents 49.95% of the Company's 50.01% ownership interest in Ivanpah. Following a sale of this 49.95% interest, the remaining 50.05% of Ivanpah would be owned by the Company, Google Inc. and BrightSource Energy Inc.

(d) Represents the Company’s 51% ownership interest in Agua Caliente. The remaining 49% of Agua Caliente is owned by MidAmerican Energy Holdings Inc.

(e) Represents the Company's remaining 25% of the Class B interests of NRG Wind TE Holdco. NRG Yield, Inc. acquired 75% of the Class B interests in November 2015. A tax equity investor owns the Class A interests in NRG Wind TE Holdco.

(f) Includes Bingham Lake, Eastridge, and Westridge projects.

Cash Grants

As of December 31, 2015, the Company had a net renewable energy grant receivable of $13 million, net of sequestration. The receivable balance reflects a reduction as compared to the December 31, 2014, balance of $135 million, net of sequestration, due primarily to a cash grant of approximately $51 million awarded by the U.S. Treasury Department to the Company for the Ivanpah project in June 2015 as well as the establishment of an indemnity receivable in the amount of $75 million relating to the agreement the Company has with SunPower relating to the CVSR project in the first quarter of 2015.

Indemnity Receivable

The Company has a receivable of $75 million pursuant to an indemnity agreement the Company has with SunPower relating to the CVSR project. 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 the U.S. Treasury Department 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. On April 2, 2015, SunPower filed its answer to the lawsuit and also a cross-complaint alleging that NRG owes SunPower $7.5 million as a result of SunPower having paid more than its required share to cover the repayment of the DOE cash grant bridge loans. In July 2015, NRG filed its answer to the cross-complaint. The court has set this case for trial on January 17, 2017.

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 (including 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, 2015, all hedges under the first liens were in-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MW 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, 2015:

Equivalent Net Sales Secured by First Lien Structure (a)	2016	2017	2018	2019
In MW (b)	2,488	936	95	—
As a percentage of total net coal and nuclear capacity (c)	43%	16%	2%	—%

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.
(b) 2016 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 and EME (including Midwest Generation) acquisitions, assets in NRG Yield, Inc. and NRG's assets that have project-level financing.

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) allocations in connection with the Capital Allocation Program including acquisitions, debt repayments, 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, 2015, commercial operations had total cash collateral outstanding of $568 million, and $768 million outstanding in letters of credit to third parties primarily to support its commercial activities for both wholesale and retail transactions (includes a $37 million letter of credit relating to deposits at the PUCT that cover outstanding customer deposits and residential advance payments). As of December 31, 2015, total collateral held from counterparties was $106 million in cash, and $184 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.

Debt Service Obligations

Principal payments on debt and capital leases as of December 31, 2015, are due in the following periods:

Description	2016	2017	2018	2019	2020	Thereafter	Total
				(In millions)			
NRG Recourse Debt:							
Senior notes, due 2018	$ —	$ —	$ 1,039	$ —	$ —	$ —	$ 1,039
Senior notes, due 2020	—	—	—	—	1,058	—	1,058
Senior notes, due 2021	—	—	—	—	—	1,128	1,128
Senior notes, due 2022	—	—	—	—	—	1,100	1,100
Senior notes, due 2023	—	—	—	—	—	936	936
Senior notes, due 2024	—	—	—	—	—	904	904
Term loan facility, due 2018	20	20	1,927	—	—	—	1,967
Tax-exempt bonds	—	—	—	—	—	455	455
Subtotal NRG Recourse Debt	20	20	2,966	—	1,058	4,523	8,587
NRG Non-Recourse Debt:							
GenOn senior notes	—	692	649	—	489	—	1,830
GenOn Americas Generation senior notes	—	—	—	—	—	695	695
GenOn Other	4	4	4	3	4	37	56
Subtotal GenOn debt (non-recourse to NRG)	4	696	653	3	493	732	2,581
Yield Operating LLC Senior Notes, due 2024	—	—	—	—	—	500	500
Yield LLC and Yield Operating LLC Revolving Credit Facility, due 2019	—	—	—	306	—	—	306
Yield Inc. Convertible Senior Notes, due 2019	—	—	—	345	—	—	345
Yield Inc. Convertible Senior Notes, due 2020	—	—	—	—	287	—	287
El Segundo Energy Center, due 2023	42	43	48	49	53	250	485
Marsh Landing, due 2017 and 2023	48	52	55	57	60	146	418
Alta Wind I-V lease financing arrangements, due 2034 and 2035	37	39	40	42	44	800	1,002
Walnut Creek, term loans due 2023	41	43	45	47	49	126	351
Tapestry, due 2021	9	10	11	11	11	129	181
Laredo Ridge, due 2028	5	5	5	5	6	78	104
Alpine, due 2022	9	9	8	8	8	112	154
Energy Center Minneapolis, due 2017 and 2025	12	13	7	11	11	54	108
Viento, due 2023	11	13	16	18	16	115	189
Yield Other	27	25	25	28	68	296	469
Subtotal NRG Yield debt (non-recourse to NRG)	241	252	260	927	613	2,606	4,899
Ivanpah, due 2033 and 2038	37	39	40	42	44	947	1,149
Agua Caliente, due 2037	30	31	32	33	34	719	879
CVSR, due 2037	23	25	26	24	21	674	793
Dandan, due 2033	20	4	4	4	4	62	98
Peaker bonds, due 2019	33	35	8	—	—	—	76
Cedro Hill, due 2025	6	10	10	9	11	57	103
NRG Other	66	37	5	7	9	191	315
Subtotal other NRG non-recourse debt	215	181	125	119	123	2,650	3,413
Subtotal all non-recourse debt	460	1,129	1,038	1,049	1,229	5,988	10,893
Subtotal long-term debt	480	1,149	4,004	1,049	2,287	10,511	19,480
Capital Leases:							
Home Solar capital leases	3	3	3	3	1	—	13
Other	1	1	1	—	—	—	3
Subtotal NRG Capital Leases	4	4	4	3	1	—	16
Total Debt and Capital Leases	$ 484	$ 1,153	$ 4,008	$ 1,052	$ 2,288	$ 10,511	19,496

In addition to the debt and capital leases shown in the above 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, 2015.

Capital Expenditures

The following tables and descriptions summarize the Company's capital expenditures for maintenance, environmental, and growth investments, for the year ended December 31, 2015, and the estimated capital expenditure and growth investments forecast for 2016.

	Maintenance	Environmental	Growth Investments	Total
		(In millions)		
NRG Business				
Gulf Coast	$ 193	$ 65	$ 20	$ 278
East	155	209	94	458
West	5	—	25	30
B2B	5	—	1	6
NRG Home Retail	30	—	—	30
NRG Home Solar	5	—	135	140
NRG Renew	11	—	208	219
NRG Yield	20	—	9	29
Corporate	37	—	56	93
Total cash capital expenditures for the year ended December 31, 2015, net of financings	461	274	548	1,283
Other investments[a]	—	—	506	506
Funding from debt financing and NRG Yield, Inc. equity issuance, net of fees	—	(37)	(409)	(446)
Funding from third party equity partners and cash grants	(33)	—	(188)	(221)
Total capital expenditures and investments, net of financings	428	237	457	1,122
Estimated capital expenditures for 2016	460	304	694	1,458
Other investments	—	—	61	61
Funding from debt financing, net of fees	—	—	(315)	(315)
Funding from third party equity partners and cash grants	—	—	(4)	(4)
NRG estimated capital expenditures for 2016, net of financings	$ 460	$ 304	$ 436	$ 1,200

(a) Other investments include restricted cash activity and $285 million for the acquisition of a 25% interest in the Desert Sunlight Solar Farm.

- *Environmental capital expenditures* — For the year ended December 31, 2015, the Company's environmental capital expenditures included DSI/ESP upgrades at the Avon Lake, Powerton and Waukegan facilities and the Joliet gas conversion to satisfy IL CPS; controls to satisfy MATS and the NSR settlement at the Big Cajun II facility; mercury controls at the W.A. Parish facility; and NO_x controls for the Sayreville and Gilbert facilities.
- *Growth Investments capital expenditures* — For the year ended December 31, 2015, the Company's growth investment capital expenditures included $343 million for solar projects, $94 million for fuel conversions, $45 million for repowering projects, $9 million for thermal projects and $57 million for the Company's other growth projects.

Environmental Capital Expenditures Estimate

NRG estimates that environmental capital expenditures from 2016 through 2020 required to comply with environmental laws will be approximately $350 million, which includes $68 million for GenOn and $263 million for Midwest Generation. These costs, the majority of which will be expended by the end of 2016, are primarily associated with (i) DSI/ESP upgrades at the Powerton facility and the Joliet gas conversion to satisfy the IL CPS and (ii) MATS compliance at the Avon Lake facility.

In connection with the acquisition of EME, as further described in Item 15 —Note 3, *Business Acquisitions and Dispositions*, to the Consolidated Financial Statements, NRG committed to fund up to $350 million in capital expenditures for plant modifications at Powerton and Joliet to comply with environmental regulations. The expected costs of these projects are included in the environmental capital expenditures detailed above.

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.

		SO_2		NO_x		Mercury		Particulate	
Units [(a)]	State	Control Equipment	Install Date	Control Equipment	Install Date	Control Equipment	Install Date	Control Equipment	Install Date
Avon 9	OH	DSI	2016	LNBOFA	2004	ACI/ESP	2016	ESP/upgrade	1970/2016
Big Cajun II 1	LA	DSI	2015	LNBOFA/ SNCR	2005/2014	ACI	2015	ESP/upgrade	1981/2015
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	1983/2015
Chalk Point 1	MD	FGD	2009	SCR	2008	FGD/ESP	2009	ESP/upgrade	1964/1980
Chalk Point 2	MD	FGD	2009	SACR	2006	FGD/ESP	2009	ESP/upgrade	1964/1980
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/ 2014	ESP	1970, 1971
Dickerson 1-3	MD	FGD	2009	SNCR	2009	FGD/FF	2009	ESP/FF	1959,1960, 1962/2003
Huntley 67-68	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	1980/2011
Joliet 6	IL	Gas Conversion	2016	OFA/SNCR	2000/2012	Gas Conversion	2016	Gas Conversion	2016
Joliet 7,8	IL	Gas Conversion	2016	LNBOFA/ SNCR	2000,01/ 2012	Gas Conversion	2016	Gas Conversion	2016
Keystone 1-2	PA	FGD	2009	SCR	2003	FGD/ESP/ SCR	2003	ESP	1967, 1968
Limestone 1-2	TX	FGD	1985-86	LNBOFA/ SNCR	2002/2022, 2023	ACI	2015	ESP	1985-1986
Morgantown 1-2	MD	FGD	2009	SCR	2007-2008	FGD/ESP	2009	ESP	1970, 1971
Powerton 5	IL	DSI	2016	OFA/SNCR	2003/2012	ACI	2009	ESP/upgrade	1973/2016
Powerton 6	IL	DSI	2014	OFA/SNCR	2002/2012	ACI	2009	ESP/upgrade	1976/2014
W.A. Parish 5, 6, 7	TX	FF co-benefit	1988	SCR	2004	ACI	2015	FF	1988
W.A. Parish 8[(b)]	TX	FGD	1982	SCR	2004	ACI	2015	FF	1988
Waukegan 7	IL	DSI	2014	LNBOFA	2002	ACI	2008	ESP/upgrade	1958/2002, 2014
Waukegan 8	IL	DSI	2015	LNBOFA	1999	ACI	2008	ESP/upgrade	1962/1999, 2015
Will County 4	IL	None	None	LNBOFA/ SNCR	1999,2001/ 2012	ACI	2009	ESP/upgrade	1963,72/ 2000

(a) NRG plans to add natural gas capabilities at its New Castle, Shawville, and Joliet facilities in 2016,
(b) Unit expected to be converted into a cogeneration facility to provide power and steam to the Petra Nova CCF.

ACI - Activated Carbon Injection
CDS - Circulating Dry Scrubber
DSI - Dry Sorbent Injection with Trona
ESP - Electrostatic Precipitator
FGD - Flue Gas Desulfurization (wet)
FF- Fabric Filter

FBL - Fluidized Bed Limestone Injection
LNBOFA - Low NO_x Burner with Overfire Air
PAL - Plantwide Applicability Limit
SCR - Selective Catalytic Reduction
SACR - Selective Auto-Catalytic Reduction
SNCR - Selective Non-Catalytic Reduction

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)		
2016	$ —	$ —	$ 62	$ 242	$ 304
2017	—	—	—	6	6
2018	—	1	—	8	9
2019	7	—	1	—	8
2020	10	—	5	8	23
Total	$ 17	$ 1	$ 68	$ 264	$ 350

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.

Common Stock Dividends

The following table lists the dividends paid during 2015:

	Fourth Quarter 2015	Third Quarter 2015	Second Quarter 2015	First Quarter 2015
Dividends per Common Share	$ 0.145	$ 0.145	$ 0.145	$ 0.145

On January 18, 2016, NRG declared a quarterly dividend on the Company's common stock of $0.145 per share, or $0.58 per share on an annualized basis, payable on February 16, 2016, to stockholders of record as of February 1, 2016. The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws and regulations. On February 29, 2016, the Company announced a reduction in its common stock dividend to $0.12 per share on an annualized basis.

Preferred Stock Dividend Payments

For the year ended December 31, 2015, NRG paid $9 million in dividend payments to holders of the Company's 2.822% Preferred Stock.

Capital Allocation Program

The Company‘s plan to allocate capital during 2016 is as follows:

- **Debt Reduction**. The Company expects to allocate approximately seventy five percent (75%) of its capital available for allocation during 2016 to additional debt repurchases. The Company may complete this action through cash purchases, exchange offers, privately negotiated transactions or otherwise, depending on prevailing market conditions, the Company's liquidity requirements and other factors.

- **Growth Investments.** The Company intends to use a portion of capital available for allocation during 2016 to complete its fuel repowerings, conversions and renewable investments.

- **Common Stock Dividends**. On February 29, 2016, the Company announced a reduction in its common stock dividend to $0.12 per share on an annualized basis. The decision to reduce the common stock dividend is a proactive measure taken by the Company in order to reallocate capital in accordance with the priorities set forth in this section.

The Company will continue to monitor market conditions in light of the Company's 2016 Capital Allocation Program to determine if adjustments are necessary in the future.

Share Repurchases

The following table shows the Company's share repurchases under the 2015 Capital Allocation Program. The purchases of common stock were made using cash on hand. Under the Company's 2016 Capital Allocation Program, the Company has not allocated capital for any additional share repurchases at this time.

Board Authorized Share Repurchases (in millions, except share and per share data)	**Amount Authorized**	**Repurchases** Q4 2014	Q1 2015	Q2 2015	Q3 2015	Q4 2015	**Total Repurchases through December 31, 2015**
Initial Phase (authorized Q4 2014)	$ 100	$ 44	$ 56	$ —	$ —	$ —	$ 100
Second Phase (authorized Q1 2015)	100	—	23	77	—	—	100
Supplemental (authorized Q2 2015)	81	—	—	30	51	—	81
Reset (authorized Q3 2015)	200	—	—	—	116	84	200
Total	$ 481	$ 44	$ 79	$ 107	$ 167	$ 84	$ 481
Average price per share		$ 26.95	$ 25.15	$ 24.53	$ 15.06	$ 15.03	$ 18.64
Shares repurchased		1,624,360	3,146,484	4,379,907	11,104,184	5,558,920	25,813,855
Quarterly dividends		$ 47	$ 49	$ 48	$ 48	$ 46	$ 238
Total capital returned to shareholders		$ 91	$ 128	$ 155	$ 215	$ 130	$ 719

Debt Reduction

The following table lists the repurchases of senior notes in 2015 in open market transactions:

Senior Note Repurchases	**Principal Redeemed (in millions)**	**Cash Paid [(a)] (in millions)**	**Average early redemption percentage**
NRG Energy, Inc.			
7.625% senior notes due 2018	$ 92	$ 97	102.23%
8.250% senior notes due 2020	5	5	96.50%
6.625% senior notes due 2023	54	82	85.97%
6.6250% senior notes due 2024	95	47	84.73%
GenOn Energy, Inc.			
7.875% senior notes due 2017	33	33	95.17%
9.500% senior notes due 2018	25	23	90.95%
9.875% senior notes due 2020	61	52	83.85%
GenOn Americas Generation LLC			
8.500% senior notes due 2021	84	73	84.91%
9.125% senior notes due 2031	71	55	77.02%
	$ 520	$ 467	

(a) Includes accrued interest.

Subsequent to year-end and through February 29, 2016, the Company repurchased an additional $171 million in aggregate principal of NRG Energy, Inc. senior notes.

Fuel Repowerings and Conversions

The table below lists the Company's currently projected repowering and conversion projects. With respect to facilities that are currently operating, the timing of the projects listed below could adversely impact the Company's operating revenues, gross margin and other operating costs during the period prior to the targeted COD.

Facility	Net Generation Capacity (MW)	Project Type	Fuel Type	Targeted COD
Fuel Conversions[(a)]				
Joliet Units 6, 7 and 8[(b)]	1,326	Environmental	Natural Gas	Summer 2016
New Castle Units 3, 4 and 5	325	Growth	Natural Gas	Summer 2016
Shawville Units 1, 2, 3 and 4	597	Growth	Natural Gas	Fall 2016
Total	2,248			
Repowerings				
Carlsbad Peakers (formerly Encina) Units 1, 2, 3, 4, 5 and GT[(c)]	527	Growth	Natural Gas	Winter 2018
Puente (formerly Mandalay) Units 1 and 2[(c)]	262	Growth	Natural Gas	Summer 2020
Cielo Lindo (formerly P.H. Robinson) Peakers 1-6	360	Growth	Natural Gas	Summer 2016
Total	1,149			
Total Fuel Repowerings and Conversions	3,397			

(a) Does not include the natural gas conversions of Dunkirk Units 2, 3 and 4, which are on hold pending the outcome of outstanding litigation.

(b) The Company has incurred and will incur environmental capital expenditures to switch to gas to satisfy MATS.

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

Cash Flow Discussion

2015 compared to 2014

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

	Year ended December 31,		
(In millions)	2015	2014	Change
Net cash provided by operating activities	$ 1,309	$ 1,510	$ (201)
Net cash used by investing activities	(1,485)	(2,903)	1,418
Net cash (used by)/provided by financing activities	(432)	1,265	(1,697)

Net Cash Provided By Operating Activities

Changes to net cash provided by operating activities were driven by:

Changes in working capital	$ 365
Increase in operating income adjusted for non-cash items	(39)
Change in cash collateral in support of risk management activities	(527)
	$ (201)

Net Cash Used By Investing Activities

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

Decrease in cash paid for acquisitions, due primarily to the acquisitions of EME and Alta Wind in 2014	$ 2,905
Decrease in cash grants, primarily reflecting the 2014 receipt of the CVSR cash grant	(834)
Increase in capital expenditures related to maintenance and environmental projects	(374)
Increase in equity investments, primarily related to 25% investment in Desert Sunlight in 2015	(301)
Decrease in proceeds from sale of assets, due to the sales of Kendall, Bayou Cove and 50% of the Company's interest in Petra Nova in 2014	(167)
Decrease in restricted cash	192
Cash proceeds to fund cash grant bridge loan payment in 2014	(57)
Other	54
	$ 1,418

Net Cash (Used)/Provided By Financing Activities

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

Net decrease in borrowing, offset by debt payments which primarily reflects the issuance of the 2021 and 2024 Senior Notes in 2014	$ (1,331)
Increase in repurchase of treasury stock	(398)
Decrease in cash contributions from noncontrolling interest	(172)
Decrease in proceeds from issuance of common stock	(20)
Increase in payments of dividends	(5)
Increase in contingent consideration payments	(4)
Increase in financing element of acquired derivatives	187
Decrease in cash paid for deferred financing costs	46
	$ (1,697)

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)

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

As of December 31, 2015, the Company had domestic pre-tax book loss of $5,105 million and foreign pre-tax book income of $11 million. For the year ended December 31, 2015, the Company generated an NOL of $263 million which is available to offset taxable income in future periods. As of December 31, 2015, the Company has cumulative domestic Federal NOL carryforwards of $4.0 billion which will begin expiring in 2026 and cumulative state NOL carryforwards of $4.2 billion for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $202 million, which do not have an expiration date. As a result of the Company's tax position, and based on current forecasts, the Company anticipates income tax payments, primarily due to state and local jurisdictions, of up to $40 million in 2016.

In addition to these amounts, the Company has $32 million of tax effected uncertain tax benefits for which the Company has recorded a non-current tax liability of $35 million until such final resolution with the related taxing authority. The $35 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 2012. 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, 2015, 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, 2015, 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 $621 million as of December 31, 2015. 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 guarantees. See also Item 15 — Note 12, *Debt and Capital Leases*, Note 22, *Commitments and Contingencies*, and Note 26, *Guarantees*, to the Consolidated Financial Statements for additional discussion.

	By Remaining Maturity at December 31,					
	2015					
Contractual Cash Obligations	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total (a)	2014 Total
	(In millions)					
Long-term debt (including estimated interest)	$ 1,607	$ 7,201	$ 4,843	$ 13,387	$ 27,038	$ 28,422
Capital lease obligations (including estimated interest)	4	8	4	1	17	8
Operating leases	341	520	484	1,367	2,712	2,955
Fuel purchase and transportation obligations	887	556	343	549	2,335	2,621
Fixed purchased power commitments	50	19	1	—	70	66
Pension minimum funding requirement (b)	30	101	172	149	452	438
Other postretirement benefits minimum funding requirement (c)	12	19	20	51	102	148
Other liabilities (d)	201	135	138	517	991	981
Total	$ 3,132	$ 8,559	$ 6,005	$ 16,021	$ 33,717	$ 35,639

(a) Excludes $34 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 $945 million of asset retirement obligations which are discussed in Item 15 — Note 13, *Asset Retirement Obligations*, to the Consolidated Financial Statements.

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

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

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

	By Remaining Maturity at December 31,					
	2015					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2014 Total
	(In millions)					
Letters of credit and surety bonds	$ 1,805	$ 92	$ —	$ 2	$ 1,899	$ 1,914
Asset sales guarantee obligations	—	—	257	—	257	292
Other guarantees	—	1	—	721	722	1,174
Total guarantees	$ 1,805	$ 93	$ 257	$ 723	$ 2,878	$ 3,380

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, 2015, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2015. 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, 2014	$ 413
Contracts realized or otherwise settled during the period	(363)
Changes in fair value	(44)
Fair value of contracts as of December 31, 2015	$ 6

	Fair Value of Contracts as of December 31, 2015				
	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	$ (97)	$ (129)	$ (20)	$ —	$ (246)
Level 2	317	(2)	(16)	(14)	285
Level 3	(26)	(5)	(1)	(1)	(33)
Total	$ 194	$ (136)	$ (37)	$ (15)	$ 6

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, 2015, NRG's net derivative asset was $6 million, a decrease to total fair value of $407 million as compared to December 31, 2014. This decrease was primarily driven by the roll-off of trades that settled during the period and losses in fair value.

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 $414 million in the net value of derivatives as of December 31, 2015.

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 $392 million in the net value of derivatives as of December 31, 2015.

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 indicating impairment
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, 2015, NRG had a valuation allowance of $3,575 million. This amount is comprised of domestic federal net deferred tax assets of approximately $2,973 million, domestic state net deferred tax assets of $542 million, foreign net operating loss carryforwards of $59 million, and foreign capital loss carryforwards of approximately $1 million. The Company believes it is more likely than not that the results of future operations will not generate sufficient taxable income which includes the future reversal of existing taxable temporary differences to realize deferred tax assets, requiring a valuation allowance to be recorded.

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 2012. 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. 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 following long-lived asset impairments were recorded during 2015, as further described in Item 15 —Note 10, *Asset Impairments*, to the Consolidated Financial Statements:

- In the fourth quarter of 2015, the Company entered into an agreement to sell the Seward facility. The Company recorded an impairment loss of $134 million as of December 31, 2015 to reduce the carrying amount of the net assets held for sale to equal the agreed-upon sales price.

- During the third quarter of 2015, the Company filed notice of its intent to retire Huntley's operating units on March 1, 2016. On October 30, 2015, NYISO released the results of its reliability study, indicating that the Huntley operating units are not needed for bulk system reliability. Accordingly the Company determined that the carrying amount of the assets was higher than the estimated future net cash flows expected to be generated by the assets and that the assets were impaired. The fair value of the Huntley operating units was determined using the income approach. The income approach utilized estimates of discounted future cash flows, which include key inputs such as forecasted contract prices, forecasted operating expenses and discount rates. The Company recorded an impairment loss of $132 million during the year ended December 31, 2015.

- During the third quarter of 2015, the Company announced that Dunkirk Unit 2 will be mothballed on January 1, 2016, at the expiration of its reliability support services agreement. The project to add natural gas-burning capabilities has been suspended, pending the outcome of litigation with respect to the gas addition contract and its validity. On October 30, 2015, NYISO released the results of its reliability study, indicating that the Dunkirk facility is not needed for system reliability. The Company determined that the carrying amount of the assets was higher than the estimated future net cash flows expected to be generated by the assets and that the assets were impaired. The fair value of the Dunkirk facility was determined using the income approach. The income approach utilized estimates of discounted future cash flows, which include key inputs such as forecasted contract prices, forecasted operating and capital expenditures and discount rates. The Company recorded an impairment loss of $160 million during the year ended December 31, 2015.

- During the fourth quarter of 2015, the Company recorded an impairment loss of $29 million to reduce the carrying value of certain solar panels to approximate fair value.

- During the fourth quarter of 2015, as the Company revised its fundamental view for long term prices in connection with the preparation of its annual budget, it was noted that the cash flows for the Limestone and W.A. Parish coal fired facilities and the Gregory combined cycle facility located in Texas were lower than the carrying amount, primarily driven by declining power prices as the cost of commodities continues to decline. As a result of these updates and in connection with the preparation of the year-end financial statements, the Company determined that the assets are impaired. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets and recognized impairment losses of $1,514 million, $1,295 million and $176 million related to Limestone, W.A. Parish, and Gregory, respectively.

NRG is also required to evaluate its equity-method and cost-method investments to determine whether or not they are impaired in accordance with ASC 323, *Investments - Equity Method and Joint Ventures*, or ASC 323. The standard for determining whether an impairment must be recorded under ASC 323 is whether a decline in the value is considered an "other than 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 year ended December 31, 2015, the Company recorded impairment losses on its equity-method and cost-method investments of $56 million due to "other than temporary" declines in value.

Goodwill and Other Intangible Assets

At December 31, 2015, NRG reported goodwill of $999 million, consisting of $337 million associated with the acquisition of Texas Genco in 2006, or NRG Texas, $341 million for its NRG Home businesses, $278 million related to the acquisition of EME and $43 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. NRG first evaluates 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 of the NRG B2B reporting unit (NRG Curtailment Solutions). The Company determined it was not more likely than not that the fair value of the goodwill attributed to this reporting unit was less than its carrying amount and accordingly, no impairment existed for the year ended December 31, 2015.

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, 2015:

Reporting Unit (Segment)	**% Fair Value Over Carrying Value**
BETM (Corporate)	138
Midwest Generation (NRG Business)	114
NRG Home Retail - Commodity (NRG Home Retail)	896
NRG Home Retail - non-Commodity (NRG Home Retail)	119
Solar Power Partners (NRG Renew)	136

The Company also performed step one of the two-step impairment test for its NRG Texas, NRG Home Solar and Goal Zero reporting units. The Company determined the fair value of these reporting units primarily using an income approach. In each case, the fair value of the reporting unit was determined to be less than its carrying amount and accordingly, the Company performed step two of the two-step impairment test. The results of the impairment tests for these reporting units are detailed below and in Item 15 - Note 10, *Asset Impairments*, to the Consolidated Financial Statements.

NRG Texas

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, which reflect the Company's long-term view of the price of natural gas. The Company's fundamental view for the longer term reflects the implied power price and heat rate that would support new build of a combined cycle gas plant in the Texas region. 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. Hedging is included to the extent of contracts already in place;
    - The Company's estimate of generation, fuel costs, capital expenditure requirements and the existing and anticipated impact of environmental regulations;
    - Based on the Company's fundamental view for the longer term, cash flows for the plants in the region were included in the fair value calculation through the end of each plants estimated useful life;
    - 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 cost savings of approximately $45 million per year and annual supply cost savings of approximately $18 million, tax affected at the appropriate tax rate and assuming this value decreases over the useful lives of the underlying plants. The estimates of annual collateral cost savings resulting from utilizing the Company's wholesale generation assets to provide supply to retail represent the cost of collateral that would otherwise need to be held in reserve to support potential postings to third parties in the case of a significant price move. This is calculated from a combination of the volume the Company would otherwise need to buy from these third parties, based on historical volumes, and historical price movements calibrated to an appropriate probability. The estimates of annual supply cost savings are based on historical volumes of retail purchases from NRG Texas, an average bid-ask spread based on broker quotes and the assumption that NRG Texas will realize half of the benefits associated with this savings.

Under step one, if the fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, the Company estimated the fair value of NRG Texas' invested capital was 76% below its carrying value as of December 31, 2015 and 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 the carrying amount of the goodwill exceeded its fair value by approximately $1.4 billion and an impairment loss of this amount was recorded.

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;
- Decrease in natural gas prices or significant changes to power plants' economics and expected generation could result in decreased realized synergies associated with estimated collateral and cost supply savings related to the combination of the NRG Texas and Texas retail businesses; and/or
- Macroeconomic factors that significantly differ from the Company's assumptions in timing or degree.

The Company noted that during 2015, the Company observed a significant decrease in its stock price, which was driven in part by depressed commodity prices and resulted in a decline in industry-wide stock prices during 2015. The Company's view on long-term commodity prices is reflected in the inputs utilized to test its goodwill and long-lived assets for impairment and reflects the current depressed commodity environment. If long-term natural gas prices remain depressed for an extended period of time, the Company's remaining goodwill associated with NRG Texas may be further impaired.

NRG Home Solar

The Company determined the fair value of the NRG Home Solar reporting unit using an income approach applying a discounted cash flow methodology to the long-term budgets for the reporting unit. The carrying amount of the reporting unit was higher than the fair value, and accordingly, the Company recognized an impairment loss of $125 million during the fourth quarter of 2015 to reduce the carrying value of the goodwill that was recognized in connection with the acquisition.

The significant assumptions utilized in determining the fair value of the reporting unit included the Company's estimates of lease growth, revenue and operating expenses, capital expenditures based on the Company's view of the cost of solar installations, working capital requirements, general and administrative expenses and customer acquisition costs. Cash flows were discounted using a discount rate applied to the internally developed cash flow projections for the NRG Home Solar reporting unit which 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 residential solar industry.

Goal Zero

During the third quarter of 2015, the Company determined that there was an indication of goodwill impairment and performed a two-step goodwill impairment test. The carrying amount of the reporting unit was higher than the fair value, and accordingly, the Company recognized an impairment loss of $36 million during the third quarter of 2015 to reduce the carrying value of the goodwill that was recognized in connection with the acquisition. The significant assumptions utilized in determining the fair value of the reporting unit included the Company's estimates of customer acquisition and related revenue, which reflect a decrease in estimated customer growth as compared to estimates at the time of the acquisition, as well as estimated operating expenses. The discount rate applied to the internally developed cash flow projects represents the weighted average cost of capital consistent with the risk inherent in future cash flows and consistent with the purchase price of the acquisition.

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, 2015, the VaR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the VaR model, was $54 million.

The following table summarizes average, maximum and minimum VaR for NRG for the years ended December 31, 2015, and 2014:

(In millions)	2015	2014
VaR as of December 31,	$ 54	$ 49
For the year ended December 31,		
Average	$ 42	$ 88
Maximum	55	142
Minimum	30	49

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, 2015, for the entire term of these instruments entered into for both asset management and trading, was $61 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, 2015, the Company would have owed the counterparties \$134 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, 2015, 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, 2015, the Company's debt fair value was \$18.3 billion and carrying value was \$19.6 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 \$348 million as of December 31, 2015, 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 \$285 million as of December 31, 2015. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2015.

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, 2015, aggregate counterparty credit exposure to a significant portion of the Company's counterparties totaled $969 million, of which the Company held collateral (cash and letters of credit) against those positions of $240 million resulting in a net exposure of $733 million. Approximately 97% of the Company's exposure before collateral is expected to roll off by the end of 2017. 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, 2015, 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	47%
Utilities, energy merchants, marketers and other	36
ISOs	17
Total	100%

Category	Net Exposure [(a)] (% of Total)
Investment grade	96%
Non-Investment grade	2
Non-Rated	2
Total	100%

(a) Counterparty credit exposure excludes uranium and 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 $247 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, 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 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, 2015, credit exposure to these counterparties was approximately $3.7 billion, of which $2.7 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, 2015, 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, $64 million, and $67 million for the years ending December 31, 2015, 2014 and 2013, 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, 2015, was $204 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2015, was $34 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 $3 million as of December 31, 2015.

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, 2015.

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 2015 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, 2015.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015, 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, 2015, 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, 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, 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, 2015, and our report dated February 29, 2016 expressed an unqualified opinion on those consolidated financial statements.

(signed) KPMG LLP

Philadelphia, PA
February 29, 2016

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, Two Harbors Investment Corp. and Uranium Energy 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. 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. and on the advisory board of Morgan Stanley Infrastructure II, L.P. 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.

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.

Mauricio Gutierrez has served as President and Chief Executive Officer of NRG since December 2015 and as a director of NRG since January 2016. Prior to December 2015, Mr. Gutierrez was the Executive Vice President and Chief Operating Officer of NRG from July 2010 to December 2015. Mr. Gutierrez also has served as the Interim President and Chief Executive Officer of NRG Yield, Inc. since December 2015 and Executive Vice President and Chief Operating Officer of NRG Yield, Inc. from December 2012 to December 2015. Mr. Gutierrez has also served on the board of NRG Yield, Inc. since its formation in December 2012. Mr. Gutierrez has been with NRG since August 2004 and served in multiple executive positions within NRG including Executive Vice President - Commercial Operations from January 2009 to July 2010 and Senior Vice President - Commercial Operations from March 2008 to January 2009. Prior to joining NRG in August 2004, Mr. Gutierrez held various commercial positions within Dynegy, Inc.

William E. Hantke has been a director of NRG since March 2006. Mr. Hantke served as Executive Vice President and Chief Financial Officer of Premcor, Inc., a refining company, from February 2002 until December 2005. Mr. Hantke was Corporate Vice President of Development of Tosco Corporation, a refining and marketing company, from September 1999 until September 2001, and he also served as Corporate Controller from December 1993 until September 1999. Prior to that position, he was employed by Coopers & Lybrand as Senior Manager, Mergers and Acquisitions from 1989 until 1990. He also held various positions from 1975 until 1988 with AMAX, Inc., including Corporate Vice President, Operations Analysis and Senior Vice President, Finance and Administration, Metals and Mining. He was employed by Arthur Young from 1970 to 1975 as Staff/Senior Accountant. Mr. Hantke was Non-Executive Chairman of Process Energy Solutions, a private alternative energy company until March 31, 2008 and served as director and Vice-Chairman of NTR Acquisition Co., an oil refining start-up, until January 2009.

Paul W. Hobby has been a director of NRG since March 2006. Mr. Hobby is the Managing Partner of Genesis Park, L.P., a Houston-based private equity business specializing in technology and communications investments which he helped to form in 1999. He previously served as the Chief Executive Officer of Alpheus Communications, Inc., a Texas wholesale telecommunications provider from 2004 to 2011, and as Former Chairman of CapRock Services Corp., the largest provider of satellite services to the global energy business from 2002 to 2006. From November 1992 until January 2001, he served as Chairman and Chief Executive Officer of Hobby Media Services and was Chairman of Columbine JDS Systems, Inc. from 1995 until 1997. Mr. Hobby 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. He was an Assistant U.S. Attorney for the Southern District of Texas from 1989 to 1992, Chief of Staff to the Lieutenant Governor of Texas, Bob Bullock, in 1991 and an Associate at Fulbright & Jaworski from 1986 to 1989. Mr. Hobby is also a director of Stewart Information Services Corporation (Stewart Title).

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

Mauricio Gutierrez has served as President and Chief Executive Officer of NRG since December 2015 and as a director of NRG since January 2016. For additional biographical information for Mr. Gutierrez, 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.

David Callen has served as Senior Vice President and Chief Accounting Officer since February 2016 and Vice President and Chief Accounting Officer from March 2015 to February 2016. In this capacity, Mr. Callen is responsible for directing NRG's financial accounting and reporting activities. Mr. Callen also has served as Vice President and Chief Accounting Officer of NRG Yield, Inc. since March 2015. Prior to this, Mr. Callen served as the Company's Vice President, Financial Planning & Analysis from November 2010 to March 2015. He previously served as Director, Finance from October 2007 through October 2010, Director, Financial Reporting from February 2006 through October 2007, and Manager, Accounting Research from September 2004 through February 2006. Prior to NRG, Mr. Callen was an auditor for KPMG LLP in both New York City and Tel Aviv Israel from October 1996 through April 2001.

John Chillemi has served as Executive Vice President, National Business Development of NRG since December 2015. In this role, Mr. Chillemi is responsible for all wholesale generation development activities for NRG across the nation. Prior to December 2015, Mr. Chillemi was Senior Vice President and Regional President, West since the acquisition of GenOn in December 2012. Mr. Chillemi served as the Regional President in California and the West for GenOn from December 2010 to December 2012, and as President and Vice President of the West at Mirant Corporation from 2007 December 2010. Mr. Chillemi has 30 years of power industry experience, beginning with Georgia Power in 1986.

Tanuja Dehne has served as Executive Vice President, Chief Administrative Officer and Chief of Staff since November 2014. In this capacity, Ms. Dehne is responsible for the oversight of NRG’s Human Resources, Information Technology, Communications, Corporate Marketing and Sustainability Departments, including NRG’s charitable giving program, M&A integrations, big data analytics and is responsible for construction of the Company's sustainable headquarters in Princeton, NJ. Ms. Dehne served as Chief of Staff from January 2014 to November 2014 and Senior Vice President, Human Resources from October 2011 to January 2014. 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 corporate 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.

Elizabeth Killinger has served as Executive Vice President and President, NRG Retail and Reliant of NRG since February 2016. Ms. Killinger was Senior Vice President and President, NRG Retail from June 2015 to February 2016 and Senior Vice President and President, NRG Texas Retail from January 2013 to June 2015. Ms. Killinger has also served as President of Reliant, a subsidiary of NRG, since October 2012. Prior to that, Ms. Killinger was Senior Vice President of Retail Operations and Reliant Residential from January 2011 to October 2012. Ms. Killinger has been with the Company and its predecessors since 2002 and has held various operational and business leadership positions within the retail organization. Prior to joining the Company, Ms. Killinger spent a decade proving strategy, management and systems consulting to energy, oilfield services and retail distribution companies across the country and in Europe.

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 "Governance" section of the Company's website at *www.nrg.com*. 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 2016 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 2016 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	3,511,079	(1)	$ 21.42	7,517,561	
Equity compensation plans not approved by security holders	898,630	(2)	24.66	1,671,633	
Total	4,409,709		$ 22.67	9,189,194	(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 8, 2014. As of December 31, 2015, there were 1,276,913 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 582,378 at a weighted-average exercise price of $56.84. See Item 15 — Note 20, *Stock-Based Compensation*, to Consolidated Financial Statements for a discussion of the NRG GenOn LTIP.

(3) Consists of 6,240,648 shares of common stock under NRG's LTIP, 1,671,633 shares of common stock under the NRG GenOn LTIP, and 1,276,913 shares of treasury stock reserved for issuance under the ESPP. In the first quarter of 2016, 299,127 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 2016 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 2016 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 2016 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, 2015, 2014, and 2013

Consolidated Statements of Comprehensive (Loss)/Income — Years ended December 31, 2015, 2014, and 2013

Consolidated Balance Sheets — As of December 31, 2015 and 2014

Consolidated Statements of Cash Flows — Years ended December 31, 2015, 2014, and 2013

Consolidated Statement of Stockholders' Equity — Years ended December 31, 2015, 2014, and 2013

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, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, 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, 2015, 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 29, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

(signed) KPMG LLP

Philadelphia, Pennsylvania
February 29, 2016

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share amounts)	For the Year Ended December 31, 2015	2014	2013
Operating Revenues			
Total operating revenues	$ 14,674	$ 15,868	$ 11,295
Cost of operations	10,755	11,794	8,130
Depreciation and amortization	1,566	1,523	1,256
Impairment losses	5,030	97	459
Selling, general and administrative	1,220	1,027	895
Acquisition-related transaction and integration costs	10	84	128
Development activity expenses	154	91	84
Total operating costs and expenses	18,735	14,616	10,952
Gain on postretirement benefits curtailment and sale of assets	21	19	—
Operating(Loss)/Income	(4,040)	1,271	343
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	36	38	7
Impairment losses on investments	(56)	—	(99)
Other income, net	33	22	13
(Loss)/gain on sale of equity-method investment	(14)	18	—
Net gain/(loss) on debt extinguishment	75	(95)	(50)
Interest expense	(1,128)	(1,119)	(848)
Total other expense	(1,054)	(1,136)	(977)
(Loss)/Income Before Income Taxes	(5,094)	135	(634)
Income tax expense/(benefit)	1,342	3	(282)
Net (Loss)/Income	(6,436)	132	(352)
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(54)	(2)	34
Net (Loss)/Income Attributable to NRG Energy, Inc.	(6,382)	134	(386)
Dividends for preferred shares	20	56	9
(Loss)/Income Available for Common Stockholders	$ (6,402)	$ 78	$ (395)
(Loss)/Earnings Per Share Attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding — basic	329	334	323
Net (Loss)/Income per Weighted Average Common Share — Basic	$ (19.46)	$ 0.23	$ (1.22)
Weighted average number of common shares outstanding — diluted	329	339	323
Net (Loss)/Income per Weighted Average Common Share — Diluted	$ (19.46)	$ 0.23	$ (1.22)
Dividends Per Common Share	$ 0.58	$ 0.54	$ 0.45

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS)/INCOME

	For the Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Net (Loss)/Income	$ (6,436)	$ 132	$ (352)
Other Comprehensive (Loss)/Income, net of tax			
Unrealized (loss)/gain on derivatives, net of income tax expense/(benefit) of $19, $(21), and $(6)	(15)	(45)	8
Foreign currency translation adjustments, net of income tax benefit of $0, $5, and $14	(11)	(8)	(24)
Available-for-sale securities, net of income tax (benefit)/expense of $(3), $(2), and $2	17	(7)	3
Defined benefit plan, net of income tax expense/(benefit) of $69, $(88), and $100	10	(129)	168
Other comprehensive income/(loss)	1	(189)	155
Comprehensive Loss	(6,435)	(57)	(197)
Less: Comprehensive (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(73)	8	34
Comprehensive Loss Attributable to NRG Energy, Inc.	(6,362)	(65)	(231)
Dividends for preferred shares	20	56	9
Comprehensive Loss Available for Common Stockholders	$ (6,382)	$ (121)	$ (240)

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2015	2014
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,518	$ 2,116
Funds deposited by counterparties	106	72
Restricted cash	414	457
Accounts receivable — trade, less allowance for doubtful accounts of $21 and $23	1,157	1,322
Inventory	1,252	1,247
Derivative instruments	1,915	2,425
Cash collateral paid in support of energy risk management activities	568	187
Renewable energy grant receivable	13	135
Current assets held-for-sale	6	—
Prepayments and other current assets	442	447
Total current assets	7,391	8,408
Property, Plant and Equipment		
In service	24,909	29,487
Under construction	627	770
Total property, plant and equipment	25,536	30,257
Less accumulated depreciation	(6,804)	(7,890)
Net property, plant and equipment	18,732	22,367
Other Assets		
Equity investments in affiliates	1,045	771
Notes receivable, less current portion	53	72
Goodwill	999	2,574
Intangible assets, net of accumulated amortization of $1,525 and $1,402	2,310	2,567
Nuclear decommissioning trust fund	561	585
Derivative instruments	305	480
Deferred income taxes	167	1,580
Non-current assets held-for-sale	105	17
Other non-current assets	1,214	1,045
Total other assets	6,759	9,691
Total Assets	$ 32,882	$ 40,466

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	As of December 31,	
	2015	2014
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 481	$ 474
Accounts payable	869	1,060
Derivative instruments	1,721	2,054
Cash collateral received in support of energy risk management activities	106	72
Accrued interest expense	242	252
Other accrued expenses	568	553
Current liabilities held-for-sale	2	—
Other current liabilities	386	394
Total current liabilities	4,375	4,859
Other Liabilities		
Long-term debt and capital leases	18,983	19,701
Nuclear decommissioning reserve	326	310
Nuclear decommissioning trust liability	283	333
Postretirement and other benefit obligations	588	727
Deferred income taxes	19	21
Derivative instruments	493	438
Out-of-market contracts, net of accumulated amortization of $664 and $562	1,146	1,244
Non-current liabilities held-for-sale	4	—
Other non-current liabilities	900	847
Total non-current liabilities	22,742	23,621
Total Liabilities	27,117	28,480
2.822% convertible perpetual preferred stock; $0.01 par value; 250,000 shares issued and outstanding	302	291
Redeemable noncontrolling interest in subsidiaries	29	19
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 416,939,950 and 415,506,176 shares issued; and 314,190,042 and 336,662,624 shares outstanding at December 31, 2015 and 2014	4	4
Additional paid-in capital	8,296	8,327
Retained (deficit)/earnings	(3,007)	3,588
Less treasury stock, at cost; 102,749,908 and 78,843,552 shares at December 31, 2015 and 2014	(2,413)	(1,983)
Accumulated other comprehensive loss	(173)	(174)
Noncontrolling interest	2,727	1,914
Total Stockholders' Equity	5,434	11,676
Total Liabilities and Stockholders' Equity	$ 32,882	$ 40,466

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Cash Flows from Operating Activities			
Net (loss)/income	$ (6,436)	$ 132	$ (352)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	37	49	84
Depreciation and amortization	1,566	1,523	1,256
Provision for bad debts	64	64	67
Amortization of nuclear fuel	45	46	36
Amortization of financing costs and debt discount/premiums	(11)	(12)	(33)
Adjustment to (gain)/loss on debt extinguishment	(75)	25	(15)
Amortization of intangibles and out-of-market contracts	81	64	49
Amortization of unearned equity compensation	41	42	38
Gain on post retirement benefits curtailment and sales of assets	(7)	(4)	(3)
Impairment losses	5,086	97	558
Changes in derivative instruments	233	(61)	164
Changes in deferred income taxes and liability for uncertain tax benefits	1,326	(154)	(67)
Changes in collateral deposits in support of risk management activities	(381)	146	(47)
Changes in nuclear decommissioning trust liability	(2)	19	15
Cash provided/(used) by changes in other working capital, net of acquisition and disposition effects:			
Accounts receivable - trade	136	(2)	(224)
Inventory	(26)	(245)	11
Prepayments and other current assets	8	36	25
Accounts payable	(218)	(12)	275
Accrued expenses and other current liabilities	(9)	(26)	(114)
Other assets and liabilities	(149)	(217)	(453)
Net Cash Provided by Operating Activities	1,309	1,510	1,270
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(31)	(2,936)	(494)
Capital expenditures	(1,283)	(909)	(1,987)
Decrease/(increase) in restricted cash, net	8	57	(22)
Decrease/(increase) in restricted cash to support equity requirements for U.S. DOE funded projects	35	(206)	(26)
Decrease/(increase) in notes receivable	18	25	(11)
Proceeds from renewable energy grants	82	916	55
Purchases of emission allowances, net of proceeds	41	(16)	5
Investments in nuclear decommissioning trust fund securities	(629)	(619)	(514)
Proceeds from sales of nuclear decommissioning trust fund securities	631	600	488
Proceeds from sale of assets, net	27	203	13
Investments in unconsolidated affiliates	(395)	(103)	—
Other	11	85	(35)
Net Cash Used by Investing Activities	(1,485)	(2,903)	(2,528)
Cash Flows from Financing Activities			
Payment of dividends to preferred and common stockholders	(201)	(196)	(154)
Net receipts from settlement of acquired derivatives that include financing elements	196	9	267
Payment for treasury stock	(437)	(39)	(25)
Sales proceeds and other contributions from noncontrolling interests in subsidiaries	647	819	531
Proceeds from issuance of common stock	1	21	16
Proceeds from issuance of long-term debt	1,004	4,563	1,777
Payment of debt issuance and hedging costs	(21)	(67)	(50)
Payments for short and long-term debt	(1,599)	(3,827)	(935)
Other	(22)	(18)	—
Net Cash (Used)/Provided by Financing Activities	(432)	1,265	1,427
Effect of exchange rate changes on cash and cash equivalents	10	(10)	(2)
Net (Decrease)/Increase in Cash and Cash Equivalents	(598)	(138)	167
Cash and Cash Equivalents at Beginning of Period	2,116	2,254	2,087
Cash and Cash Equivalents at End of Period	$ 1,518	$ 2,116	$ 2,254

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Common Stock	Additional Paid-In Capital	Retained Earnings/ (Accumulated Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Noncontrolling Interest	Total Stockholders' Equity
				(In millions)			
Balances at December 31, 2012	$ 4	$ 7,587	$ 4,230	$ (1,920)	$ (150)	$ 518	$ 10,269
Net (loss)/income			(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)	—
Dividend for refinancing of preferred stock			(47)				(47)
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
Net loss			(6,382)			(37)	(6,419)
Other comprehensive income/(loss)					1	(4)	(3)
Sale of assets to NRG Yield, Inc.		(56)				83	27
ESPP share purchases		(1)		7			6
Equity-based compensation		26	(2)				24
Purchase of treasury stock				(437)			(437)
Common stock dividends			(191)				(191)
Preferred stock dividends			(20)				(20)
Distributions to noncontrolling interests						(159)	(159)
Contributions from noncontrolling interests						234	234
Acquisition of noncontrolling interests by NRG Yield, Inc.						74	74
Impact of NRG Yield, Inc. public offering						599	599
Equity component of NRG Yield, Inc. convertible notes						23	23
Balances at December 31, 2015	$ 4	$ 8,296	$ (3,007)	$ (2,413)	$ (173)	$ 2,727	$ 5,434

See notes to Consolidated Financial Statements.

Note 1 — Nature of Business

General

NRG Energy, Inc., or NRG or the Company, is an integrated competitive power company, which 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 has one of the nation's largest and most diverse competitive generation portfolios balanced with the nation's largest competitive retail energy business. The Company owns and operates approximately 50,000 MW 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 names “NRG”, "Reliant" and other retail brand names owned by NRG.

The following table summarizes NRG's global generation portfolio as of December 31, 2015:

	Global Generation Portfolio[a] (In MW)								
	NRG Business								
Generation Type	Gulf Coast	East	West	NRG Home Solar [b]	NRG Renew [c]	NRG Yield [d]	Total Domestic	Other (International)	Total Global
Natural gas [e]	8,651	7,876	6,085	—	—	1,879	24,491	144	24,635
Coal [f]	5,114	10,122	—	—	—	—	15,236	605	15,841
Oil [g]	—	5,581	—	—	—	190	5,771	—	5,771
Nuclear	1,176	—	—	—	—	—	1,176	—	1,176
Wind	—	—	—	—	1,061	2,005	3,066	—	3,066
Utility Scale Solar	—	—	—	—	845	482	1,327	—	1,327
Distributed Solar	—	—	—	93	60	9	162	—	162
Total generation capacity	14,941	23,579	6,085	93	1,966	4,565	51,229	749	51,978
Capacity attributable to noncontrolling interest	—	—	—	—	(638)	(2,053)	(2,691)	—	(2,691)
Total net generation capacity	14,941	23,579	6,085	93	1,328	2,512	48,538	749	49,287

(a) Includes 90 active fossil fuel and nuclear plants, 16 Utility Scale Solar facilities, 36 wind farms and multiple Distributed Solar facilities. All Utility Scale Solar and Distributed Solar facilities are described in MW on an alternating current basis. MW figures provided represent nominal summer net MW capacity of power generated as adjusted for the Company's owned or leased interest excluding capacity from inactive/mothballed units.

(b) Includes the aggregate production capacity of installed and activated residential solar energy systems. Also includes capacity from operating portfolios of residential solar assets held by RPV Holdco, a partnership between NRG Home Solar and NRG Yield, Inc.

(c) Includes Distributed Solar capacity from assets held by DGPV Holdco, a partnership between NRG Renew DG Holdings LLC and NRG Yield, Inc.

(d) Does not include NRG Yield, Inc.'s thermal converted (MWt) capacity, which is part of the NRG Yield operating segment.

(e) Natural gas generation portfolio does not include: 463 MW related to Osceola, which was mothballed on January 1, 2015; 636 MW related to Coolwater, which was retired on January 1, 2015; 16 MW related to SD Jets Kearny 1, which was deactivated in March 2015; 160 MW related to Glen Gardner, which was retired on May 1, 2015; 98 MW related to Gilbert, which was retired on May 1, 2015; 335 MW related to El Segundo 4, which was deactivated on December 31, 2015; and 60 MW related to SD Jets Kearny 2A-2D, which were deactivated on December 31, 2015.

(f) Coal generation portfolio does not include: 251 MW related to Will County, which was retired on April 15, 2015; 597 MW related to Shawville, which was mothballed on May 31, 2015; 575 MW related to Big Cajun Unit 2, which was converted to natural gas in July 2015; 401 MW related to Portland, which was deactivated on December 1, 2015; and 75 MW related to Dunkirk 2, which was mothballed on December 31, 2015.

(g) Oil generation portfolio does not include 212 MW related to Werner, which was retired on May 1, 2015.

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, 2015, NRG's retail businesses within NRG Home and NRG Business served approximately 2.77 million Recurring customers and approximately 624,000 Discrete customers.

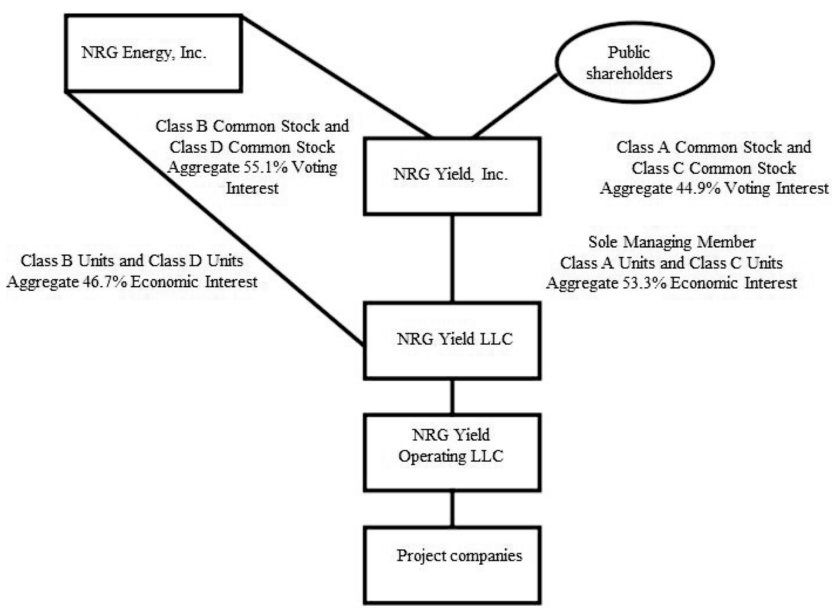
NRG Renew operates the Company's existing renewables business, including operation of the NRG Yield renewable assets. NRG Renew is also one of the largest solar and wind power developers and owner-operators in the U.S., having developed, constructed and financed a full range of solutions for utilities, schools, municipalities and commercial market segments.

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.

NRG Yield, Inc. Ownership

In 2013, 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. In 2013 and 2014, NRG Yield, Inc. issued Class A common stock to its public shareholders and utilized the proceeds to acquire a controlling interest in NRG Yield LLC, through its ownership of Class A units. At that time, the Company owned the Class B common stock of NRG Yield, Inc. and the Class B units of NRG Yield LLC. On May 14, 2015, NRG Yield, Inc. completed a stock split in connection with which each outstanding share of Class A common stock was split into one share of Class A common stock and one share of Class C common stock, and each outstanding share of Class B common stock was split into one share of Class B common stock and one share of Class D common stock. A similar split was effected at NRG Yield LLC with respect to its member units. The Company consolidates NRG Yield, Inc. for financial reporting purposes as it maintains a controlling voting interest, and presents the public ownership of the Class A and Class C common stock as noncontrolling interest. The Company receives distributions from NRG Yield LLC, through its ownership of Class B and Class D units.

The following table represents the structure of NRG Yield, Inc. as of December 31, 2015:



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 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 BETM, 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. Of these funds, approximately $45 million is designated for current debt service payments, $61 million is designated to fund operating expenses, and $21 million is designated to fund distributions, with the remaining $287 million restricted for reserves including debt service, performance obligations and other reserves, as well as capital expenditures.

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. During the year ended December 31, 2015, the Company recorded a lower of weighted average cost or market adjustment of $19 million related to fuel oil.

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, 2015, 2014, and 2013. 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. Beginning in 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, 2015, 2014, and 2013, was $30 million, $29 million, and $64 million, respectively.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and depreciated 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. As discussed below, as of December 31, 2015, the Company adopted ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,* and reclassified debt issuance costs to be presented as a direct deduction from the carrying amount of the related debt in both the current and prior periods.

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, 2015.

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.

The Company first assesses 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. 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.

For further discussion of goodwill and goodwill impairment losses recognized during 2015, refer to Note 11, *Goodwill and Other Intangibles*.

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 $165 million, $387 million and $166 million for the years ended December 31, 2015, 2014, and 2013, 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 $309 million, $341 million and $356 million as of December 31, 2015, 2014, and 2013, respectively, for retail energy sales and services.

Consumer product revenues are recognized when title and risk of loss pass to the retailer, distributor, or end-customer and when all of the following have occurred: a firm sales agreement is in place, delivery has occurred, pricing is fixed and determinable, and collection is reasonably assured. Revenue is recognized as the net amount expected to be received after deducting estimated amounts for product returns, discounts, and allowances based on historical return rates and reasonable judgment.

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 exceeds 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, 2015, 2014, and 2013 was $777 million, $544 million, and $260 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, 2015, 2014, and 2013, NRG's revenues and cost of operations included gross receipts taxes of $110 million, $108 million, and $88 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 ($85 million, $86 million and $90 million as of December 31, 2015, 2014, and 2013, 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 are no longer probable 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, 2015, 2014, and 2013, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2015, 2014, and 2013 were $(10) million, $1 million and $15 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. Distributions from equity method investments that represent a return on the Company's investment are included within cash flows from operating activities and distributions from equity method investments that represent a return of the Company's investment are included within cash flows from investing activities.

Tax Equity Arrangements

NRG's redeemable noncontrolling interest in subsidiaries and noncontrolling interest, included in interest, 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 at book value, or HLBV, method. Under the HLBV method, the amounts reported as noncontrolling interest 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 interest 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.

Redeemable Noncontrolling Interest

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. The following table reflects the changes in the Company's redeemable noncontrolling interest balance for the years ended December 31, 2015, and 2014.

	(In millions)
Balance as of December 31, 2013	$ 2
Cash contributions from noncontrolling interest	36
Comprehensive loss attributable to noncontrolling interest	(19)
Balance as of December 31, 2014	19
Cash contributions from noncontrolling interest	27
Comprehensive loss attributable to noncontrolling interest	(17)
Balance as of December 31, 2015	$ 29

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 marketing and advertising costs as incurred which are included within selling, general and administrative expenses. Marketing and advertising expenses for the years ended December 31, 2015, 2014, and 2013 were $307 million, $208 million, and $195 million, respectively. 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. Advertising expenses for the years ended December 31, 2015, 2014 and 2013 were $135 million, $87 million, and $69 million, respectively.

Business Combinations

The Company accounts for its business combinations in accordance with ASC 805, *Business Combinations,* or ASC 805. ASC 805 requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

Use of Estimates

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

In recording transactions and balances resulting from business operations, NRG uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of energy commodity contracts, environmental liabilities, legal costs incurred in connection with recorded loss contingencies, and assets acquired and liabilities assumed in business combinations, among others. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes.

Recent Accounting Developments

ASU 2016-01 — In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, or ASU No. 2016-01. The amendments of ASU No. 2016-01 eliminate available-for-sale classification of equity investments and require that equity investments (except those accounted for under the equity method of accounting, or those that result in consolidation of the investee) to be generally measured at fair value with changes in fair value recognized in net income. Further, the amendments require that financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category and form of financial asset. The guidance in ASU No. 2016-01 is effective for financial statements issued for fiscal years beginning after December 15, 2017, and interim periods within those annual periods. The Company is currently evaluating the impact of the standard on the Company's results of operations, cash flows and financial position.

ASU 2015-17 — In November 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes*, or ASU No. 2015-17. The amendments of ASU No. 2015-17 require that deferred tax liabilities and assets, as well as any related valuation allowance, be presented as noncurrent in a classified statement of financial position. The guidance in ASU No. 2015-17 is effective for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those annual periods. The amendments may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. Early adoption is permitted. The Company adopted ASU No. 2015-17 for the year ended December 31, 2015 and elected to apply the amendments retrospectively. The adoption did not have any impact on the Company's results of operations, cash flows, or net assets.

ASU 2015-16 — In September 2015, the FASB issued ASU No. 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*, or ASU No. 2015-16. The amendments of ASU No. 2015-16 require that an acquirer recognize measurement period adjustments to the provisional amounts recognized in a business combination in the reporting period during which the adjustments are determined. Additionally, the amendments of ASU No. 2015-16 require the acquirer to record in the same period's financial statements the effect on earnings of changes in depreciation, amortization or other income effects, if any, as a result of the measurement period adjustment, calculated as if the accounting had been completed at the acquisition date as well as disclosing either on the face of the income statement or in the notes the portion of the amount recorded in current period earnings that would have been recorded in previous reporting periods. The guidance in ASU No. 2015-16 is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments should be applied prospectively. The adoption of this standard is not expected to have a material impact on the Company's results of operations, cash flows or financial position.

ASU 2015-03 and ASU 2015-15 — In April 2015, the FASB issued ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*, or ASU No. 2015-03. The amendments of ASU No. 2015-03 were issued to reduce complexity in the balance sheet presentation of debt issuance costs. ASU No. 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this standard. Additionally, in August 2015, the FASB issued ASU No. 2015-15, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements,* or ASU No. 2015-15, as ASU No. 2015-03 did not specifically address presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements. ASU No. 2015-15 allows an entity to continue to defer and present debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The guidance in ASU No. 2015-03 and ASU No. 2015-15 is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. The Company adopted ASU No. 2015-03 for the year ended December 31, 2015, and the adoption did not have a material impact on the Company's balance sheets on a gross basis and had no impact on net assets.

ASU 2015-02 — In February 2015, the FASB issued ASU No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*, or ASU No. 2015-02. The amendments of ASU No. 2015-02 were issued in an effort to minimize situations under previously existing guidance in which a reporting entity was required to consolidate another legal entity in which that reporting entity did not have: (1) the ability through contractual rights to act primarily on its own behalf; (2) ownership of the majority of the legal entity's voting rights; or (3) the exposure to a majority of the legal entity's economic benefits. ASU No. 2015-02 affects reporting entities that are required to evaluate whether they should consolidate certain legal entities. All legal entities are subject to reevaluation under the revised consolidation model. The guidance in ASU No. 2015-02 is effective for periods beginning after December 15, 2015. Early adoption is permitted. The Company adopted the standard effective January 1, 2015, and the adoption of this standard did not impact the Company's results of operations, cash flows or financial position.

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 adopted this standard effective January 1, 2015, and the adoption did not impact the Company's results of operations, cash flows or 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. In August 2015, the FASB issued ASU 2015-14, which formally deferred the effective date by one year to make the guidance of ASU No. 2014-09 effective for annual reporting periods beginning after December 15, 2017, including interim periods therein. Early adoption is permitted, but not prior to the original effective date, which was for annual reporting periods beginning after December 15, 2016. The Company is currently evaluating the impact of the standard on the Company's results of operations, cash flows and financial position.

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:

Acquisitions

2015 Acquisition of Desert Sunlight

On June 29, 2015, NRG Yield, Inc., through its subsidiary Yield Operating, acquired 25% of the membership interest in Desert Sunlight Investment Holdings, LLC, which owns two solar photovoltaic facilities that total 550 MW located in Desert Center, California from EFS Desert Sun, LLC, an affiliate of GE Energy Financial Services, for a purchase price of $285 million. The Company accounts for its 25% investment as an equity method investment.

2014 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 MW 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. The Alta X and XI power purchase agreements began in January 2016 with terms of 22 years and currently sell energy and renewable energy credits on a merchant basis.

The purchase price of the Alta Wind Assets was $923 million, which was comprised of a 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 accounting for the business combination was completed as of August 11, 2015, at which point the fair values became final. The following table summarizes the provisional amounts recognized for assets acquired and liabilities assumed as of December 31, 2015, as well as adjustments made through August 11, 2015, when the allocation became final. The purchase price of $923 million was allocated as follows:

	Acquisition Date Fair Value at December 31, 2014	Measurement period adjustments	Revised Acquisition Date
		(In millions)	
Assets			
Cash	$ 22	—	$ 22
Current and non-current assets	49	(2)	47
Property, plant and equipment	1,304	6	1,310
Intangible assets	1,177	(6)	1,171
Total assets acquired	2,552	(2)	2,550
Liabilities			
Debt	1,591	—	1,591
Current and non-current liabilities	38	(2)	36
Total liabilities assumed	1,629	(2)	1,627
Net assets acquired	$ 923	$ —	$ 923

2014 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 allocated to the following: $40 million to accounts receivable-trade, $64 million to customer relationships, $9 million to trade names, $14 million to current assets, $21 million to derivative assets, $47 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 existing retail and generation assets. The acquired assets and liabilities are included within the NRG Home Retail segment. The accounting for the Dominion acquisition was completed as of March 30, 2015, at which point the provisional fair values became final with no material changes.

2014 Acquisition of EME

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 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*.

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 accounting for the EME acquisition was completed as of March 31, 2015, at which point the fair values became final. The following table summarizes the provisional amounts recognized for assets acquired and liabilities assumed as of December 31, 2014, as well as adjustments made through March 31, 2015, when the allocation became final. Measurement period adjustments primarily reflect the tax impact of the acquisition date fair values and final estimates for asset retirement obligations. The purchase price of $3.5 billion was allocated as follows:

	Acquisition Date Fair Value at December 31, 2014	Measurement period adjustments	Revised Acquisition Date
		(In millions)	
Assets			
Cash	1,422	—	$ 1,422
Current assets	724	72	796
Property, plant and equipment	2,438	(3)	2,435
Intangible assets	172	—	172
Goodwill	334	(56)	278
Non-current assets	773	—	773
Total assets acquired	5,863	13	5,876
Liabilities			
Current and non-current liabilities	629	13	642
Out-of-market contracts and leases	159	—	159
Long-term debt	1,249	—	1,249
Total liabilities assumed	2,037	13	2,050
Less: noncontrolling interest	352	—	352
Net assets acquired	$ 3,474	$ —	$ 3,474

2013 Acquisition of 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.

2013 Acquisition of 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 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.

Dispositions

2016 Disposition of Shelby

On November 9, 2015, the Company, through its subsidiary GenOn, Inc., entered into an agreement with Rockland Power Partners II, LP to sell 100% of its interest in Shelby County Energy Center, LLC, or Shelby, for cash consideration of $46 million. Shelby owns a 352 MW natural gas-fired facility located in Illinois. At December 31, 2015, NRG had $1 million of current assets, $22 million of non-current assets, and $1 million of current liabilities classified as held for sale for Shelby on its balance sheet. The sale is expected to be completed in March of 2016, and the transaction is expected to result in a gain recognized recorded in the consolidated results of operations during the first quarter of 2016.

2016 Disposition of Seward

On November 24, 2015, the Company, through its subsidiary GenOn, Inc., entered into an agreement with Robindale Energy Services, Inc. to sell 100% of its interest in Seward Generation, LLC, or Seward, for cash consideration of $75 million. Seward owns a 525 MW coal-fired facility in Pennsylvania. The transaction triggered an impairment indicator as the sale price was less than the carrying amount of the assets, and, as a result, the assets were considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount of the assets and the agreed-upon sale price. The Company recorded an impairment loss of $134 million for the year ended December 31, 2015, to reduce the carrying amount of the assets held for sale to the fair market value. At December 31, 2015, NRG had $5 million of current assets, $83 million of non-current assets, $1 million of current liabilities and $4 million of non-current liabilities classified as held for sale for Seward on its balance sheet. On February 2, 2016, GenOn completed the sale of Seward. For further discussion on this impairment, refer to Note 10 — *Asset Impairments*.

2015 Disposition of Altenex

On December 31, 2015, the Company completed the sale of its 32% interest in Altenex, LLC to Edison Energy, LLC and Edison Energy NewCo 2, LLC for cash consideration of $26 million. The Company had accounted for its investment in Altenex as an equity method investment and recognized a loss of $14 million as a result of the transaction within the Company's consolidated statements of operations.

2014 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.

2014 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 a portion of 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 $106 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. In February 2016, Petra Nova Parish Holdings LLC received notice of an additional $23 million in U.S. DOE funding.

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.

Transfers of Assets under Common Control

On November 3, 2015, the Company sold 75% of the Class B interests of NRG Wind TE Holdco, which owns a portfolio of 12 wind facilities totaling 814 net MW, to NRG Yield, Inc. NRG Yield Inc. paid total cash consideration of $209 million, subject to working capital adjustments. NRG Yield, Inc. will be responsible for its pro-rata share of non-recourse project debt of $193 million and noncontrolling interest associated with a tax equity structure of $159 million (as of the acquisition date). In February 2016, the company made a final working capital payment of $2 million to NRG Yield, Inc. reducing total cash consideration to $207 million.

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 cash consideration of $489 million, including $9 million of working capital adjustments, plus assumed project level debt of $737 million.

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 above sales were recorded as transfers of entities under common control and the related assets were transferred at their carrying value.

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,			
	2015		2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets				
Notes receivable [(a)]	$ 73	$ 73	$ 91	$ 91
Liabilities				
Long-term debt, including current portion [(b)]	19,620	18,263	20,366	20,361

(a) Includes the current portion of notes receivable which is recorded in prepayments and other current assets on the Company's consolidated balance sheets.
(b) Excludes deferred financing costs, which are recorded as a reduction to long-term debt 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, 2015			
	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	$ —	$ —	$ 17	$ 17
Available-for-sale securities	9	—	—	9
Other [(a)]	14	—	—	14
Nuclear trust fund investments:				
Cash and cash equivalents	6	—	—	6
U.S. government and federal agency obligations	54	1	—	55
Federal agency mortgage-backed securities	—	59	—	59
Commercial mortgage-backed securities	—	25	—	25
Corporate debt securities	—	81	—	81
Equity securities	280	—	54	334
Foreign government fixed income securities	—	1	—	1
Other trust fund investments:				
U.S. government and federal agency obligations	1	—	—	1
Derivative assets:				
Commodity contracts	622	1,449	149	2,220
Total assets	$ 986	$ 1,616	$ 220	$ 2,822
Derivative liabilities:				
Commodity contracts	$ 868	$ 1,036	$ 182	$ 2,086
Interest rate contracts	—	128	—	128
Total liabilities	$ 868	$ 1,164	$ 182	$ 2,214

(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, 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) Primarily consists of mutual funds held in a rabbi trusts for non-qualified deferred compensation plans for certain former 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, 2015, between Levels 1 and 2. The following tables reconcile, for the years ended December 31, 2015, and 2014, 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, 2015				
	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, 2015	$ 18	$ 11	$ 52	$ 80	$ 161
Total losses realized/unrealized:					
Included in earnings	(1)	(11)	—	(100)	(112)
Included in nuclear decommissioning obligations	—	—	(2)	—	(2)
Purchases	—	—	4	(19)	(15)
Transfers into Level 3 [(b)]	—	—	—	3	3
Transfers out of Level 3 [(b)]	—	—	—	3	3
Ending balance as of December 31, 2015	$ 17	$ —	$ 54	$ (33)	$ 38
Losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets or liabilities still held as of December 31, 2015	$ —	$ —	$ —	$ (30)	$ (30)

(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, 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/(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
Transfer 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.

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 7% of derivative assets and 8% 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 for interest rate swaps is calculated utilizing the bilateral method based on published default probabilities. For commodities, 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. For interest rate swaps and commodities, 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, 2015, the credit reserve resulted in a $5 million increase in fair value which is composed of a $2 million gain in OCI and a $3 million gain in operating revenue and cost of operations. 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, 2015, 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.

NRG's significant positions classified as Level 3 include physical and financial power and physical coal executed in illiquid markets as well as financial transmission rights, or FTRs. The significant unobservable inputs used in developing fair value include illiquid power and coal location pricing which is derived as a basis to liquid locations. The basis spread is based on observable market data when available or derived from historic prices and forward market prices from similar observable markets when not available. For FTRs, NRG uses the most recent auction prices to derive the fair value.

The following tables quantify the significant unobservable inputs used in developing the fair value of the Company's Level 3 positions as of December 31, 2015, and December 31, 2014:

	Significant Unobservable Inputs						
	December 31, 2015						
	Fair Value				Input/Range		
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
				(In millions)			
Power Contracts	$ 86	$ 100	Discounted Cash Flow	Forward Market Price (per MWh)	$ 10	$ 92	$ 27
Coal Contracts	—	12	Discounted Cash Flow	Forward Market Price (per ton)	28	45	35
FTRs	63	70	Discounted Cash Flow	Auction Prices (per MWh)	(98)	87	—
	$ 149	$ 182					

	Significant Unobservable Inputs						
	December 31, 2014						
	Fair Value				Input/Range		
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
				(In millions)			
Power Contracts	$ 195	$ 154	Discounted Cash Flow	Forward Market Price (per MWh)	$ 15	$ 92	$ 47
Coal Contracts	3	1	Discounted Cash Flow	Forward Market Price (per ton)	53	56	54
FTRs	111	75	Discounted Cash Flow	Auction Prices (per MWh)	(29)	30	—
	$ 309	$ 230					

The following table provides sensitivity of fair value measurements to increases/(decreases) in significant unobservable inputs as of December 31, 2015, and December 31, 2014:

Significant Unobservable Input	Position	Change In Input	Impact on Fair Value Measurement
Forward Market Price Power/Coal	Buy	Increase/(Decrease)	Higher/(Lower)
Forward Market Price Power/Coal	Sell	Increase/(Decrease)	Lower/(Higher)
FTR Prices	Buy	Increase/(Decrease)	Higher/(Lower)
FTR Prices	Sell	Increase/(Decrease)	Lower/(Higher)

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, 2015, the Company recorded $568 million of cash collateral paid and $106 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.

Counterparty Credit Risk

As of December 31, 2015, counterparty credit exposure, excluding credit risk exposure under certain long-term agreements, was $969 million and NRG held collateral (cash and letters of credit) against those positions of $240 million, resulting in a net exposure of $733 million. Approximately 97% of the Company's exposure before collateral is expected to roll off by the end of 2017. 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	47%
Utilities, energy merchants, marketers and other	36
ISOs	17
Total	100%

Category	Net Exposure [(a)] (% of Total)
Investment grade	96%
Non-Investment grade	2
Non-Rated	2
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 $247 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, 2015, aggregate credit risk exposure managed by NRG to these counterparties was approximately $3.7 billion, including $2.7 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, 2015, 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, $64 million, and $67 million for the years ending December 31, 2015, 2014, and 2013, 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 units' asset optimization will generally not qualify for hedge accounting treatment, with any changes in fair value likely to be reflected on a mark-to-market basis in the statement of operations. Most of the retail load contracts either qualify for the NPNS exception or fail to meet the criteria for a derivative and the majority of the 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 counterparties 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; and
- 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; and
- 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, 2015, 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 2021;
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG's generation assets through 2018; and
- Other energy derivatives instruments extending through 2024.

Also, as of December 31, 2015, 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 2018;
- Power transmission contracts through 2025;
- Natural gas transportation contracts and storage agreements through 2030; and
- Coal transportation contracts through 2029.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company's issuance of variable rate debt. In order to manage the Company's interest rate risk, NRG enters into interest rate swap agreements. As of December 31, 2015, 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, 2015, and 2014. 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, 2015	December 31, 2014
		(In millions)	
Emissions	Short Ton	1	2
Coal	Short Ton	35	57
Natural Gas	MMBtu	293	(58)
Oil	Barrel	1	1
Power	MWh	(74)	(56)
Capacity	MW/Day	(1)	—
Interest	Dollars	$ 2,326	$ 3,440
Equity	Shares	1	2

The increase in the natural gas position was primarily the result of additional retail hedges, as well as the settlement of generation hedge positions. The decrease in the interest rate position was primarily the result of settling the Alta X and Alta XI interest rate swaps in connection with the repayment of project-level debt, as described in Note 12, *Debt and Capital Leases*.

Fair Value of Derivative Instruments

The following table summarizes the fair value within the derivative instrument valuation on the balance sheet:

(In millions)	Fair Value — Derivative Assets — December 31, 2015	Derivative Assets — December 31, 2014	Derivative Liabilities — December 31, 2015	Derivative Liabilities — December 31, 2014
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$ —	$ —	$ 42	$ 55
Interest rate contracts long-term	—	2	68	74
Total Derivatives Designated as Cash Flow or Fair Value Hedges	—	2	110	129
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	—	—	5	8
Interest rate contracts long-term	—	—	13	28
Commodity contracts current	1,915	2,425	1,674	1,991
Commodity contracts long-term	305	477	412	336
Equity contracts long-term	—	1	—	—
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	2,220	2,903	2,104	2,363
Total Derivatives	$ 2,220	$ 2,905	$ 2,214	$ 2,492

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		
	Gross Amounts of Recognized Assets/ Liabilities	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
As of December 31, 2015	(In millions)			
Commodity contracts:				
Derivative assets	$ 2,220	$ (1,616)	$ (113)	$ 491
Derivative liabilities	(2,086)	1,616	271	(199)
Total commodity contracts	134	—	158	292
Interest rate contracts:				
Derivative liabilities	(128)	—	—	(128)
Total derivative instruments	$ 6	$ —	$ 158	$ 164

As of December 31, 2014	Gross Amounts Not Offset in the Statement of Financial Position			
	Gross Amounts of Recognized Assets/ Liabilities	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
	(In millions)			
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

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, 2015		
	Energy Commodities	Interest Rate	Total
	(In millions)		
Accumulated OCI balance at December 31, 2014	$ (1)	$ (67)	$ (68)
Reclassified from accumulated OCI to income:			
Due to realization of previously deferred amounts	1	14	15
Mark-to-market of cash flow hedge accounting contracts	—	(48)	(48)
Accumulated OCI balance at December 31, 2015, net of $16 tax	—	(101)	(101)
Losses expected to be realized from OCI during the next 12 months, net of $3 tax	$ —	$ (18)	$ (18)

There were no gains or losses recognized in income from the ineffective portion of cash flow hedges for the year ended December 31, 2015.

	Year Ended December 31, 2014		
	Energy Commodities	Interest Rate	Total
	(In millions)		
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)

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	Interest Rate	Total
		(In millions)	
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.

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.

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,		
	2015	2014	2013
		(In millions)	
Unrealized mark-to-market results			
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$ (275)	$ (15)	$ (105)
Reversal of acquired gain positions related to economic hedges	(106)	(333)	(357)
Net unrealized gains on open positions related to economic hedges	9	361	177
Total unrealized mark-to-market (losses)/gains for economic hedging activities	(372)	13	(285)
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	(46)	1	(50)
Reversal of acquired gain positions related to trading activity	(14)	(32)	—
Net unrealized (losses)/gains on open positions related to trading activity	(16)	45	7
Total unrealized mark-to-market (losses)/gains for trading activity	(76)	14	(43)
Total unrealized (losses)/gains	$ (448)	$ 27	$ (328)

	Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Unrealized (losses)/gains included in operating revenues	$ (320)	$ 515	$ (621)
Unrealized (losses)/gains included in cost of operations	(128)	(488)	293
Total impact to statement of operations — energy commodities	$ (448)	$ 27	$ (328)
Total impact to statement of operations — interest rate contracts	$ 17	$ (31)	$ 15

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, 2015, the $9 million gain from economic hedge positions was primarily the result of an increase in the value of forward sales of electricity due to a decrease in power prices.

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.

During 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 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 the value of forward sales of natural gas and electricity due to a decrease in forward power and gas prices and an increase in the value of forward purchases of coal due to an increase in forward coal prices.

During 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, 2015, was $204 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2015, was $34 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 $3 million as of December 31, 2015.

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, 2015				As of December 31, 2014			
(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	$ 6	$ —	$ —	—	$ 14	$ —	$ —	—
U.S. government and federal agency obligations	55	1	—	11	47	2	—	11
Federal agency mortgage-backed securities	59	1	—	25	74	2	—	25
Commercial mortgage-backed securities	25	—	2	28	25	—	1	30
Corporate debt securities	81	1	1	10	78	2	1	11
Equity securities	334	199	—	—	344	211	—	—
Foreign government fixed income securities	1	—	—	9	3	1	—	16
Total	$ 561	$ 202	$ 3		$ 585	$ 218	$ 2	

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 using the specific identification method.

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Realized gains	$ 21	$ 29	$ 25
Realized losses	14	8	8
Proceeds from sale of securities	631	600	488

Note 7 — Inventory

Inventory consisted of:

	As of December 31,	
	2015	2014
	(In millions)	
Fuel oil	$ 312	$ 375
Coal/Lignite	471	414
Natural gas	12	16
Spare parts	437	424
Other	20	18
Total Inventory	$ 1,252	$ 1,247

During the year ended December 31, 2015, the Company recorded a lower of weighted average cost or market adjustment related to fuel oil of $19 million.

Note 8 — Notes Receivable

Notes receivable consist of fixed and variable rate notes related primarily to amounts owed to the Company from transmission owners for certain projects for the financing of network upgrades. NRG's notes receivable were as follows:

	As of December 31,	
	2015	2014
	(In millions)	
Notes receivable	$ 73	$ 91
Less current maturities[(a)]	20	19
Total notes receivable — noncurrent	$ 53	$ 72

(a) 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
	2015	2014	Lives
	(In millions)		
Facilities and equipment	$ 22,676	$ 27,457	1-40 Years
Land and improvements	1,226	1,194	
Nuclear fuel	545	490	5 Years
Office furnishings and equipment	462	346	2-10 Years
Construction in progress	627	770	
Total property, plant, and equipment	25,536	30,257	
Accumulated depreciation	(6,804)	(7,890)	
Net property, plant, and equipment	$ 18,732	$ 22,367	

The Company recorded long-lived asset impairments during 2015, as further described in Note 10, *Asset Impairments.*

Note 10 — Asset Impairments

2015 Impairment Losses

Seward — As described in Note 3, *Business Acquisitions and Dispositions*, on November 24, 2015, the Company entered into an agreement with Robindale Energy Services, Inc. to sell 100% of its interest in Seward for cash consideration of $75 million. The transaction triggered an impairment indicator as the sale price was less than the carrying amount of the assets, and, as a result, the assets were considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount of the assets and the agreed-upon sale price. The Company recorded an impairment loss of $134 million for the year ended December 31, 2015, to reduce the carrying amount of the assets held for sale to the fair market value.

Limestone and W.A. Parish — During the fourth quarter of 2015, as the Company updated its view for long-term prices in connection with the preparation of its annual budget, it was noted that the cash flows for the Limestone and W.A. Parish coal-fired facilities located in Texas were lower than the carrying amount, primarily driven by declining power prices as the cost of commodities continues to decline and the assets were impaired. The fair value of the Limestone and W.A. Parish plants was determined using an income approach by applying a discounted cash flow methodology to the long-term budgets for each respective plant. The income approach utilized estimates of discounted future cash flows, which were Level 3 fair value measurements, and include key inputs such as forecasted power prices, fuel costs and emissions credit expense, forecasted operating and capital expenditures and discount rates. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets and recognized impairment losses of $1,514 million and $1,295 million related to Limestone and W.A. Parish, respectively.

Huntley — On August 25, 2015, the Company filed a notice with the NYSPSC of its intent to retire Huntley's operating units on March 1, 2016. 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*. On October 14, 2015, the Company filed a cost-of-service filing at FERC in anticipation that the Huntley operating units would be needed for reliability purposes, proposing a reliability must run service agreement for a four-year period beginning on March 1, 2016. On October 30, 2015, NYISO released the results of its reliability study, indicating that the Huntley operating units are not needed for bulk system reliability. The Company considered the impact of the reliability study conducted and evaluated the estimated cash flows associated with the facility. Accordingly, the Company determined that the carrying amount of the assets was higher than the estimated future net cash flows expected to be generated by the assets and that the assets were impaired. The fair value of the Huntley operating units was determined using the income approach. The income approach utilized estimates of discounted future cash flows, which were Level 3 fair value measurements, and include key inputs such as forecasted contract prices, forecasted operating expenses and discount rates. The Company recorded an impairment loss of $132 million during the year ended December 31, 2015.

Dunkirk — The Company signed a ten-year agreement in November 2014 with National Grid to add natural gas-burning capabilities at the Dunkirk facility. On August 25, 2015, NRG announced that Dunkirk Unit 2 would be mothballed on January 1, 2016 at the expiration of its reliability support services agreement. The project to add natural gas-burning capabilities has been suspended, pending the outcome of litigation with respect to the gas addition contract and its validity. On October 30, 2015, NYISO released the results of its reliability study, indicating that the Dunkirk facility is not needed for system reliability. In connection with the planned mothball of the facility, the pending litigation and the latest reliability assessment completed by NYISO, the Company evaluated whether the related fixed assets were impaired. The Company determined that the carrying amount of the assets was higher than the estimated future net cash flows expected to be generated by the assets and that the assets were impaired. The fair value of the Dunkirk facility was determined using the income approach. The income approach utilized estimates of discounted future cash flows, which were Level 3 fair value measurements, and include key inputs such as forecasted contract prices, forecasted operating and capital expenditures and discount rates. The Company recorded an impairment loss of $160 million during the year ended December 31, 2015.

Gregory — During the fourth quarter of 2015, the Company determined that the carrying amount of the assets was higher than the estimated future net cash flows expected to be generated by the assets and that the assets were impaired. The fair value of the Gregory facility was determined using the income approach, which utilized estimates of discounted future cash flows, which were Level 3 fair value measurements, and include key inputs such as forecasted prices, operating and capital expenditures and discount rates. The Company recorded an impairment loss of $176 million during the year ended December 31, 2015.

Solar Panels — During the fourth quarter of 2015, the Company recorded an impairment loss of $29 million to reduce the carrying value of certain solar panels to their approximate fair value.

Investments — During the fourth quarter of 2015, the Company reviewed certain of its cost method and equity method investments and concluded that losses incurred by these investments were other than temporary. These losses were primarily driven by the sustained decline in stock price of a publicly traded investment as well as change in financing structures of certain non-publicly traded investments. As a result, the Company recorded losses related to these investments of $56 million.

2014 Impairment Losses

Coolwater — During the fourth quarter of 2014, the Company determined that it would retire 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 higher 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 recorded during the fourth quarter of 2014.

Osceola — During the third quarter of 2014, the Company determined that it would mothball 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 higher than the future net cash flows expected to be generated by the assets and as a result, the assets were 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 during the third quarter of 2014, 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 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 higher 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 were 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 $999 million as of December 31, 2015, and $2.6 billion as of December 31, 2014. The Company initially 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 $278 million of goodwill in connection with the 2014 acquisition of EME, which is discussed further in Note 3, *Business Acquisitions and Dispositions*. During the year ended December 31, 2015, the Company recorded goodwill impairment charges of $1.5 billion, the details of which are discussed below. As of December 31, 2015, and 2014, NRG had approximately $620 million and $831 million, respectively, of goodwill that is deductible for U.S. income tax purposes in future periods.

NRG Texas — In connection with the annual impairment assessment, the Company performed step one of the two-step impairment test for the NRG Texas reporting unit, for which $1.7 billion of goodwill was recognized as part of the Texas Genco acquisition in 2006. The Company determined the fair value of the NRG Texas reporting unit primarily using an income approach through which the Company applied a discounted cash flow methodology to the long-term budgets for all plants in the regions. Significant inputs impacting the income approach include the Company's views of power and fuel prices for the first five-year period and the Company's view for the longer term, which were finalized in connection with the preparation of the fourth quarter financial statements, projected generation based on an hourly dispatch meant to simulate the dispatch of each unit into the power market which is impacted by power prices, fuel prices, and the physical and economic characteristics of each plant, intangible value to NRG Texas for synergies it provides to NRG's retail businesses, and the discount rate applied to cash flow projections. Under step one, the estimated fair value of the NRG Texas invested capital was 76% below its carrying value as of December 31, 2015, and the Company concluded step two was required. Based on the results of step two of the impairment test, the Company determined the carrying amount of the reporting unit was higher than the fair value, and accordingly, the Company recognized an impairment loss of $1.4 billion as of December 31, 2015.

NRG Home Solar — The Company performed the two-step impairment test as part of its annual impairment testing for the NRG Home Solar reporting unit utilizing an income approach developed through applying a discounted cash flow methodology to the long-term budget for the reporting unit. As a result, the Company determined that the carrying value of the reporting unit was higher than the fair value, and accordingly, the Company recognized an impairment loss of $125 million during the year ended December 31, 2015 to reduce the carrying value of the goodwill that was recognized in connection with acquisitions made by NRG Home Solar.

Goal Zero — During the third quarter of 2015, the Company agreed to relieve the Goal Zero seller of all known and unknown claims in return for the seller's agreement to forego all contingent consideration. Concurrently, the Company determined that there was an indication of goodwill impairment and performed an impairment test. The carrying amount of the reporting unit was higher than the fair value, and accordingly, the Company recognized an impairment loss of $36 million during the third quarter of 2015 to reduce the carrying value of the goodwill that was recognized in connection with the acquisition.

Intangible Assets

The Company's intangible assets as of December 31, 2015, primarily reflect intangible assets established with the acquisitions of various companies 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 NO_x 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 to revenues, 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, 2015	Emission Allowances	Contracts: Energy Supply	Contracts: Fuel	Contracts: Customer	Customer Relationships	Marketing Partnerships	Trade Names	PPA	Other	Total
	(In millions)									
January 1, 2015	$ 1,018	$ 54	$ 72	$ 16	$ 831	$ 88	$ 353	$ 1,269	$268	$3,969
Purchases	77	—	—	—	3	—	—	—	57	137
Usage	(33)	—	—	—	—	—	—	—	(62)	(95)
Write-off of fully amortized balances	(154)	—	—	—	—	—	—	—	—	(154)
Impairment	—	—	—	—	—	—	(6)	—	(5)	(11)
Other	12	—	—	—	—	—	(5)	(6)	(12)	(11)
December 31, 2015	920	54	72	16	834	88	342	1,263	246	3,835
Less accumulated amortization[a]	(502)	(47)	(65)	(6)	(624)	(41)	(137)	(75)	(28)	(1,525)
Net carrying amount	$ 418	$ 7	$ 7	$ 10	$ 210	$ 47	$ 205	$ 1,188	$218	$2,310

(a) Adjusted for write-off of fully amortized emissions allowances of $154 million.

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.

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

Amortization	2015	2014	2013
		(In millions)	
Emission allowances	$ 99	$ 124	$ 104
Energy supply contracts	5	6	6
Fuel contracts	2	2	2
Customer contracts	2	—	53
Customer relationships	67	70	72
Marketing partnerships	14	15	8
Trade names	23	21	29
Power purchase agreements	50	24	1
Other	15	6	4
Total amortization	$ 277	$ 268	$ 279

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

		Contracts								
Year Ended December 31,	Emission Allowances	Energy Supply	Fuel	Customer	Customer Relationships	Marketing Partnerships	Trade Names	PPA	Other	Total
2016	$ 112	$ 7	$ 2	$ 1	$ 48	$ 9	$ 23	$ 63	$ 10	$ 275
2017	53	—	1	1	33	5	23	63	10	189
2018	48	—	—	1	20	5	23	63	10	170
2019	32	—	—	1	16	4	23	63	9	148
2020	17	—	—	1	14	4	23	63	7	129

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, 2015, the value of emission allowances held-for-sale is $22 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.

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)		
2016	$ 16	47	$ 42	$ 105
2017	16	47	37	100
2018	16	47	32	95
2019	17	47	29	93
2020	17	47	29	93

Note 12 — Debt and Capital Leases

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

	As of December 31, 2015	As of December 31, 2014	December 31, 2015 Interest Rate % [(a)]
	(In millions except rates)		
NRG Recourse Debt:			
Senior notes, due 2018	$ 1,039	$ 1,130	7.625
Senior notes, due 2020	1,058	1,063	8.250
Senior notes, due 2021	1,128	1,128	7.875
Senior notes, due 2022	1,100	1,100	6.250
Senior notes, due 2023	936	990	6.625
Senior notes, due 2024	904	1,000	6.250
Term loan facility, due 2018	1,964	1,983	L+2.00
Tax Exempt Bonds	455	406	4.125 - 6.00
Subtotal NRG Recourse Debt	8,584	8,800	
NRG Non-Recourse Debt:			
GenOn senior notes	1,956	2,133	7.875 - 9.875
GenOn Americas Generation senior notes	752	929	8.500 - 9.125
GenOn Other	56	60	
Subtotal GenOn debt (non-recourse to NRG)	2,764	3,122	
Yield Operating LLC Senior Notes, due 2024	500	500	5.375
Yield LLC and Yield Operating LLC Revolving Credit Facility, due 2019	306	—	L+2.75
Yield Inc. Convertible Senior Notes, due 2019	330	326	3.500
Yield Inc. Convertible Senior Notes, due 2020	266	—	3.250
El Segundo Energy Center, due 2023	485	506	L+1.625 - L+2.25
Marsh Landing, due 2017 and 2023	418	464	L+1.75 - L+1.875
Alta Wind I-V lease financing arrangements, due 2034 and 2035	1,002	1,036	5.696 - 7.015
Alta Wind X, due 2021	—	300	L+2.00
Alta Wind XI, due 2021	—	191	L+2.00
Walnut Creek, term loans due 2023	351	391	L+1.625
Tapestry, due 2021	181	192	L+1.625
Laredo Ridge, due 2028	104	108	L+1.875
Alpine, due 2022	154	163	L+1.750
Energy Center Minneapolis, due 2017, and 2025	108	121	5.95 - 7.25
Viento, due 2023	189	196	L+2.75
Yield Other	469	489	various
Subtotal Yield debt (non-recourse to NRG)	4,863	4,983	
Ivanpah, due 2033 and 2038	1,149	1,183	2.285 - 4.256
Agua Caliente, due 2037	879	898	2.395 - 3.633
CVSR, due 2037	793	815	2.339 - 3.775
Dandan, due 2033	98	54	L+2.25
Peaker bonds, due 2019	72	100	L+1.07
Cedro Hill, due 2025	103	111	L+3.125
NRG Other	315	300	various
Subtotal other NRG non-recourse debt	3,409	3,461	
Subtotal all non-recourse debt	11,036	11,566	
Subtotal long-term debt (including current maturities)	19,620	20,366	
Capital leases:			
Home Solar capital leases	13	—	various
Chalk Point capital lease, due 2015	—	5	8.190
Other	3	3	various
Subtotal long-term debt and capital leases (including current maturities)	19,636	20,374	
Less current maturities	481	474	
Less debt issuance costs[(b)]	$ 172	$ 199	
Total long-term debt and capital leases	$ 18,983	$ 19,701	

(a) As of December 31, 2015, L+ equals 3 month LIBOR plus x%, with the exception of the Viento term loan, which is 6 month LIBOR plus x% and the Marsh Landing term loan, Walnut Creek loan, and Yield Operating LLC Revolving Credit facility, which are 1 month LIBOR plus x%

(b) Total net debt reflects the reclassification of deferred financing costs to reduce long-term debt as further described in Note 2, *Summary of Significant Accounting Policies*.

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

	As of December 31,	
	2015	2014
	(in millions)	
Term loan facility, due 2018 [(a)]	$ (3)	$ (4)
Peaker bonds, due 2019 [(b)]	(4)	(6)
Yield, Inc. Convertible notes, due 2019	(15)	(19)
Yield, Inc. Convertible notes, due 2020	(21)	—
GenOn senior notes, due 2017 [(c)]	23	41
GenOn senior notes, due 2018 [(c)]	59	83
GenOn senior notes, due 2020 [(c)]	44	60
GenOn Americas Generation senior notes, due 2021 [(c)]	32	46
GenOn Americas Generation senior notes, due 2031 [(c)]	25	33
Total premium/(discount)	$ 140	$ 234

(a) Discount of $1 million is related to current maturities in 2015 and 2014.

(b) Discount of $2 million are related to current maturities in 2015 and 2014.

(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.

Consolidated Annual Maturities

Annual payments based on the maturities of NRG's debt and capital leases, for the years ending after December 31, 2015, are as follows:

	(In millions)
2016	$ 484
2017	1,153
2018	4,008
2019	1,052
2020	2,288
Thereafter	10,511
Total	$ 19,496

NRG Recourse Debt

Senior Notes

2015 Senior Notes Repurchases

During the fourth quarter of 2015, the Company repurchased $246 million in aggregate principal of the following outstanding Senior Notes in the open market for $231 million, including accrued interest.

Amount in millions, except rates	Principal Repurchased	Average Early Redemption Percentage	Gain/(Loss) on Debt Extinguishment
8.25% Senior Note, due 2020	$ 5	96.500%	$ —
6.625% Senior Note, due 2023	54	85.972%	7
6.25% Senior Note, due 2024	95	84.725%	14
7.625% Senior Note, due 2018	92	102.232%	(2)
Total	$ 246		$ 19

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.

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 November 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.

2014 Senior Notes Redemptions

In 2014, the Company redeemed $1.4 billion in aggregate principal of its Senior Notes, due 2019 for $1.5 billion, including accrued interest.

Amount in millions, except rates	**Principal Redeemed**	**Average Early Redemption Percentage**	**Loss on Debt Extinguishment**
8.5% Senior Note, due 2019	$ 607	105.764%	$ 45
7.625% Senior Note, due 2019	800	104.169%	41
Total	$ 1,407		$ 86

Senior Notes Outstanding

As of December 31, 2015, NRG had six outstanding issuances of senior notes, or Senior Notes:

(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.

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%.

2020 Senior Notes

NRG may redeem some or all of the 2020 Senior 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%

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%

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%

2023 Senior Notes

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 2023 Senior 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%

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%. 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 of December 31, 2015, a total of $1.1 billion of 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.

Tax Exempt Bonds

	As of December 31,		
	2015	2014	Interest Rate %
Amount in millions, except rates			
Indian River Power tax exempt bonds, due 2040	57	57	6.000
Indian River Power LLC, tax exempt bonds, due 2045	190	190	5.375
Dunkirk Power LLC, tax exempt bonds, due 2042	59	59	5.875
Fort Bend County, tax exempt bonds, due 2045	22	10	4.125
Fort Bend County, tax exempt bonds, due 2038	54	54	4.750
Fort Bend County, tax exempt bonds, due 2042	73	36	4.750
Total	$ 455	$ 406	

NRG Non-Recourse Debt

The following are descriptions of certain indebtedness of NRG's subsidiaries that are outstanding as of December 31, 2015. 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, 2015, NRG had net assets of $5.6 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

	As of December 31,		
	2015	2014	Interest Rate %
Amount in millions, except rates			
Senior unsecured notes, due 2017	714	766	7.875
Senior unsecured notes, due 2018	708	757	9.500
Senior unsecured notes, due 2020	534	610	9.875
Total	$ 1,956	$ 2,133	

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.

Repurchase of GenOn Senior Notes

During the fourth quarter of 2015, the Company repurchased $119 million in aggregate principal of the following outstanding Senior Notes in the open market for $108 million, including accrued interest.

Amount in millions, except rates	Principal Repurchased	Average Early Redemption Percentage	Gain on Debt Extinguishment
Senior unsecured notes, due 2017	$ 33	95.172%	$ 3
Senior unsecured notes, due 2018	25	90.950%	5
Senior unsecured notes, due 2020	61	83.847%	15
Total	$ 119		$ 23

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, 2015, GenOn failed 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, 2015, GenOn net assets of $277 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.

GenOn may redeem some or all of the Senior Notes due 2020 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%

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.

GenOn Americas Generation Senior Notes

	As of December 31,		
Amount in millions, except rates	2015	2014	Interest Rate %
Senior unsecured notes, due 2021	398	496	8.500
Senior unsecured notes, due 2031	354	433	9.125
Total	$ 752	$ 929	

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.

Repurchase of GenOn Americas Generation Senior Notes

During the fourth quarter of 2015, the Company repurchased $155 million in aggregate principal of the following outstanding Senior Notes in the open market for $128 million, including accrued interest.

Amount in millions, except rates	**Principal Repurchased**	**Average Early Redemption Percentage**	**Gain on Debt Extinguishment**
Senior unsecured notes, due 2021	$ 84	84.910%	$ 20
Senior unsecured notes, due 2031	71	77.018%	22
Total	$ 155		$ 42

2021 and 2031 GenOn Senior Notes

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.

Yield Operating LLC Senior Notes

2024 Yield Operating 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 15th and August 15th 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.

Yield LLC and Yield Operating LLC Revolving Credit Facility

NRG Yield LLC and its direct wholly owned subsidiary, NRG Yield Operating LLC, entered into a senior secured revolving credit facility, which was amended on June 26, 2015, to, among other things, increase the availability from $450 million to $495 million. The revolving credit facility can be used for cash or for the issuance of letters of credit. At December 31, 2015, there was $306 million outstanding and $56 million of letters of credit were issued under the revolving credit facility.

Yield, Inc. Convertible Notes

2020 Yield Inc. Convertible Notes

On June 29, 2015, NRG Yield, Inc. closed on its offering of $287.5 million aggregate principal amount of 3.25% Convertible Senior Notes due 2020, or the 2020 Convertible Notes. The 2020 Convertible Notes are convertible, under certain circumstances, into NRG Yield, Inc. Class C common stock, cash or a combination thereof at an initial conversion price of $27.50 per Class C common share, which is equivalent to an initial conversion rate of approximately 36.3636 shares of Class C common stock per $1,000 principal amount of notes. Interest on the 2020 Convertible Notes is payable semi-annually in arrears on June 1 and December 1 of each year, commencing on December 1, 2015. The 2020 Convertible Notes mature on June 1, 2020, unless earlier repurchased or converted in accordance with their terms. Prior to the close of business on the business day immediately preceding December 1, 2019, the 2020 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 2020 Convertible Notes are accounted for in accordance with ASC 470-20, under which 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 is being amortized to interest expense over the term of the notes.

2019 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 2019 Convertible Notes. The 2019 Convertible Notes were 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 2019 Convertible Notes. Effective May 15, 2015, the conversion rate was adjusted to 42.9644 shares of Class A common stock per $1,000 principal amount of 2019 Convertible Notes in accordance with the terms of the related indenture. Interest on the 2019 Convertible Notes is payable semi-annually in arrears on February 1 and August 1 of each year, commencing on August 1, 2014. The 2019 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 2019 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 2019 Convertible Notes are accounted for in accordance with ASC 470-20. 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 is being amortized to interest expense over the term of the notes. The 2019 Convertible Notes are guaranteed by NRG Yield Operating LLC and NRG Yield LLC.

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that are outstanding as of December 31, 2015.

Alta Wind X and Alta Wind XI due 2021

On June 30, 2015, the Company entered into a tax equity financing arrangement through which Yield Operating, a subsidiary of NRG Yield, Inc., received $119 million in net proceeds. These proceeds, as well as proceeds obtained from the June 29, 2015, NRG Yield, Inc. common stock issuance and the 2020 Convertible Notes issuance, were utilized to repay all of the outstanding project indebtedness associated with Alta Wind X and Alta Wind XI facilities. The Company also settled interest rate swaps associated with the project level debt for Alta Wind X and Alta Wind XI and incurred a fee of $17 million.

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, 2015**	**Interest Rate**	**Maturity Date**	**Amount Outstanding as of December 31, 2015**	**Interest Rate**	**Maturity Date**
Alta Wind I	$ 252	7.015%	12/30/2034	$ 16	3.250%	1/5/2021
Alta Wind II	198	5.696%	12/30/2034	28	2.750%	6/30/2017& 12/31/2017
Alta Wind III	206	6.067%	12/30/2034	28	2.750%	4/13/2018
Alta Wind IV	133	5.938%	12/30/2034	19	2.750%	8/24/2018
Alta Wind V	213	6.071%	6/30/2035	31	2.750%	10/24/2018
Total	$ 1,002			$ 122		

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. The Company received additional default notices for various items. The facility is secured by the assets of High Lonesome Mesa and is non-recourse to NRG.

On November 3, 2015, the lender sent a notice of acceleration and indicated that it will accept the Company's interest in the assets in lieu of repayment. As of December 31, 2015, $57 million was outstanding under the project financing agreement. On January 27, 2016, High Lonesome Mesa, LLC (HLM) filed at FERC for approval to transfer 100% of the ownership interests in HLM to subsidiaries of the lien holders (Macquarie Bank Limited and Hannon Armstrong Capital, LLC). HLM requested FERC approval by March 11, 2016. Upon receipt of FERC approval the Company will transfer 100% of its interest in HLM to the lien holders.

Dandan Financing

In December 2013, 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 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 January 2033, 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, 2015, $81 million was outstanding under the construction loan, $17 million under the cash grant loan and $5 million in letters of credit in support of the project were issued. On January 29, 2016, the construction loan converted to a $79 million term loan with $23 million outstanding under the cash grant loan. In addition, a $4 million debt service letter of credit was issued replacing the $5 million construction letter of credit that was outstanding at year end.

El Segundo Energy Center Credit Agreement

On May 29, 2015, NRG West Holdings LLC amended its financing agreement to increase borrowings under the Tranche A facility by $5 million and to reduce the related interest rate to LIBOR plus an applicable margin of 1.625% from May 29, 2015, to August 31, 2017, LIBOR plus an applicable margin of 1.75% from September 1, 2017, to August 31, 2020, and LIBOR plus 1.875% from September 1, 2020, through the maturity date; and to reduce Tranche B loan interest rate to LIBOR plus an applicable margin of 2.25% from May 29, 2015, to August 31, 2017, LIBOR plus 2.375% from September 1, 2017, to August 31, 2020, and LIBOR plus an applicable margin of 2.50% from September 1, 2020, through the maturity date and to reduce the working capital facility by $9 million. The proceeds of the increased borrowing were used to pay costs associated with the refinancing. Further, the amendment resulted in a $7 million loss on debt extinguishment.

As of December 31, 2015, under the West Holdings Credit Agreement, West Holdings had outstanding $426 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.

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.

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.

In December of 2015 and 2014, NRG contributed an additional $13 million and $29 million, respectively, in equity to Peakers to meet its debt service requirements. As of December 31, 2015, $76 million in principal remained outstanding on these bonds.

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, 2015.

Non-Recourse Debt	% of Principal	Fixed Interest Rate	Floating Interest Rate	Notional Amount at December 31, 2015 (In millions)	Effective Date	Maturity Date
NRG Peaker Finance Co. LLC	100%	6.673%	3-mo. LIBOR + 1.07%	$ 76	June 18, 2002	June 10, 2019
NRG West Holdings LLC	75%	2.417%	3-mo. LIBOR	358	November 30, 2011	August 31, 2023
South Trent Wind LLC	75%	3.265%	3-mo. LIBOR	46	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	30	September 30, 2011	December 31, 2029
NRG Solar Alpine LLC	85%	2.744%	3-mo. LIBOR	122	various	December 31, 2029
NRG Solar Alpine LLC	85%	2.421%	3-mo. LIBOR	9	June 24, 2014	June 30, 2025
NRG Solar Avra Valley LLC	85%	2.333%	3-mo. LIBOR	51	November 30, 2012	November 30, 2030
NRG Marsh Landing	75%	3.244%	3-mo. LIBOR	387	June 28, 2013	June 30, 2023
Other	75%	various	various	154	various	various
EME Project Financings						
Broken Bow	75%	2.960%	3-mo. LIBOR	41	December 31, 2013	December 21, 2027
Cedro Hill	90%	4.290%	3-mo. LIBOR	93	December 31, 2010	December 31, 2025
Crofton Bluffs	75%	2.748%	3-mo. LIBOR	21	December 31, 2013	December 21, 2027
Laredo Ridge	75%	2.310%	3-mo. LIBOR	83	March 31, 2011	March 31, 2026
Tapestry	75%	2.210%	3-mo. LIBOR	163	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	170	various	various
Viento Funding II	90%	4.985%	6-mo. LIBOR	65	July 11, 2023	June 30, 2028
Walnut Creek Energy	75%	various	3-mo. LIBOR	311	June 28, 2013	May 31, 2023
WCEP Holdings	90%	4.003%	3-mo. LIBOR	46	June 28, 2013	May 21, 2023
Subtotal EME				1,053		
Alta Wind Project Financings						
AWAM	100%	2.470%	3-mo. LIBOR	19	May 22, 2013	May 15, 2031
Subtotal Alta Wind				19		
Total				2,326		

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, 2015, and 2014, along with the additions, reductions and accretion related to the Company's ARO obligations for the year ended December 31, 2015:

	(In millions)
Balance as of December 31, 2014	$ 763
Revisions in estimates for current obligations	122
Additions	18
Additions for acquisitions	2
Spending for current obligations	(11)
Accretion — Expense	35
Accretion — Nuclear decommissioning	16
Balance as of December 31, 2015	$ 945

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 in 2012, 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 $33 million to the Company's pension plans in 2016.

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. On December 31, 2014, NRG merged eight qualified pension plans into two separate qualified pension plans, the NRG Pension Plan for Bargained Employees and the NRG Pension Plan. The NRG Pension Plan for Bargained Employees, GenOn Mirant Bargaining Unit Pension Plan, GenOn First Energy Pension Plan, GenOn Duquesne Pension Plan, and GenOn REMA Pension Plan were merged into the NRG Pension Plan for Bargained Employees. The NRG Texas Retirement Plan, and GenOn Mirant Pension Plan were merged into the NRG Pension Plan for Non-Bargained Employees and renamed the NRG Pension Plan. These actions were conducted to simplify internal administration of the plans, reduce regulatory filings, and lower fees paid to outside vendors. The benefits provided to current participants in the Plans were not impacted.

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		
	2015	2014	2013
	(In millions)		
Service cost benefits earned	$ 32	$ 30	$ 30
Interest cost on benefit obligation	53	53	47
Expected return on plan assets	(62)	(62)	(55)
Amortization of unrecognized net loss/(gain)	2	(6)	9
Curtailment	—	—	(1)
Net periodic benefit cost	$ 25	$ 15	$ 30

	Year Ended December 31,		
	Other Postretirement Benefits		
	2015	2014	2013
	(In millions)		
Service cost benefits earned	$ 3	$ 3	$ 4
Interest cost on benefit obligation	9	9	9
Amortization of unrecognized prior service credit	(5)	(17)	—
Amortization of unrecognized net loss	1	—	—
Curtailment gain	(14)	—	—
Net periodic benefit (credit)/cost	$ (6)	$ (5)	$ 13

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	
	2015	2014	2015	2014
	(In millions)			
Benefit obligation at January 1	$ 1,305	$ 1,060	$ 238	$ 191
Obligations resulting from the EME acquisition	—	43	—	16
Service cost	32	30	3	3
Interest cost	53	53	9	9
Plan amendments	—	—	(6)	(18)
Actuarial (gain)/loss	(120)	174	(31)	46
Employee and retiree contributions	—	—	2	3
Benefit payments	(74)	(55)	(12)	(12)
Curtailment	—	—	(25)	—
Benefit obligation at December 31	1,196	1,305	178	238
Fair value of plan assets at January 1	988	880	—	—
Actual return on plan assets	(26)	85	—	—
Employee and retiree contributions	—	—	2	3
Employer contributions	28	78	10	9
Benefit payments	(74)	(55)	(12)	(12)
Fair value of plan assets at December 31	916	988	—	—
Funded status at December 31 — excess of obligation over assets	$ (280)	$ (317)	$ (178)	$ (238)

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

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
	(In millions)			
Current liabilities	$ —	$ —	$ 12	$ 10
Non-current liabilities	280	317	166	228

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	
	2015	2014	2015	2014
	(In millions)			
Net loss/(gain)	$ 68	$ 101	$ (9)	$ 34
Prior service cost/(credit)	3	4	(9)	(7)

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

	Year Ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
	(In millions)			
Net actuarial (gain)/loss	$ (31)	$ 152	$ (31)	$ 46
Amortization of net actuarial (gain)/loss	(2)	6	(1)	—
Prior service (credit)/cost	(1)	—	(7)	(18)
Amortization of prior service cost	—	—	5	17
Curtailment	—	—	(11)	—
Total recognized in other comprehensive (income)/loss	$ (34)	$ 158	$ (45)	$ 45
Total recognized in net periodic pension (credit)/cost and other comprehensive (income)/loss	$ (8)	$ 173	$ (37)	$ 40

The change in net actuarial loss/(gain) from 2014 to 2015 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 $2 million, respectively.

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

	As of December 31,	
	Pension Benefits	
	2015	2014
	(In millions)	
Projected benefit obligation	$ 1,196	$ 1,305
Accumulated benefit obligation	1,115	1,172
Fair value of plan assets	916	988

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, 2015		
	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	$ —	$ 255	$ 255
Common/collective trust investment — non-U.S. equity	—	147	147
Common/collective trust investment — global equity	—	90	90
Common/collective trust investment — fixed income	—	400	400
Partnerships/joint ventures	—	18	18
Short-term investment fund	6	—	6
Total	$ 6	$ 910	$ 916

	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

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	2015	2014	2015	2014
Discount rate	4.52%	4.16%	4.55%	4.20%
Rate of compensation increase	3.00%	3.45%	N/A	N/A
Health care trend rate	—	—	7.25% grading to 5.0% in 2025	8.6% grading to 5.0% in 2023

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	2015	2014	2013	2015	2014	2013
Discount rate	4.16%	4.99%	4.16%	4.20%	5.06%	4.31%
Expected return on plan assets	6.36%	6.81%	7.12%	—	—	—
Rate of compensation increase	3.45%	3.65%	3.57%	—	—	—
Health care trend rate	—	—	—	8.6% grading to 5.0% in 2023	8.5% grading to 5.5% in 2019	8.3% grading to 5.3% 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.

In 2016, NRG will change the approach utilized to estimate the service cost and interest cost components of net periodic benefit cost for pension and postretirement benefit plans. Historically, the Company estimated these components by using a single weighted average discount rate derived from the yield curve used to measure the benefit obligation. The Company will elect to use a spot rate approach in the estimation of the components of benefit cost by applying specific spot rates along the yield curve to the relevant projected cash flows, as this provides a better estimate of service and interest costs. This is considered a change in estimate and, accordingly, will account for it prospectively starting in 2016. This change does not affect the measurement of NRG's total benefit obligation.

The target allocations of NRG's pension plan assets were as follows for the year ended December 31, 2015:

U.S. equity	27%
Non-U.S. equity	15%
Global equity	10%
Emerging market equity	3%
U.S. fixed income	45%

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., global, and emerging market equities, as well as among growth, value, small and large capitalization stocks.

Investment risk and performance are monitored on an ongoing basis through quarterly portfolio reviews of each asset fund class to a related performance benchmark, if applicable, and annual pension liability measurements. Performance benchmarks are composed of the following indices:

Asset Class	Index
U.S. equities	Dow Jones U.S. Total Stock Market Index
Non-U.S. equities	MSCI All Country World Ex-U.S. IMI Index
Global equities	MSCI World Index
Emerging market equities	MSCI Emerging Markets Index
Fixed income securities	Barclays Capital Long Term Government/Credit Index & Barclays US Aggregate Bond Index

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)			
2016	$	60	$	12	$	—
2017		64		9		—
2018		67		10		—
2019		71		10		—
2020		75		10		—
2021-2025		409		52		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	$	1	$	(1)
Effect on postretirement benefit obligation		13		(11)

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in STP, as discussed further in Note 27, *Jointly Owned Plants*. STPNOC, which operates and maintains STP, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. For the year ended December 31, 2015, NRG reimbursed STPNOC $9 million towards its defined benefit plans. For the year ended December 31, 2014, NRG reimbursed STPNOC $14 million towards its defined benefit plans. In 2016, NRG expects to reimburse STPNOC $7 million for its contribution 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			
	2015		2014		2015		2014	
	(In millions)							
Funded status — STPNOC benefit plans	$	(63)	$	(71)	$	(26)	$	(30)
Net periodic benefit cost/(credit)		10		6		(8)		3
Other changes in plan assets and benefit obligations recognized in other comprehensive income		(8)		37		6		(29)

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,		
	2015	2014	2013
		(In millions)	
Company contributions to defined contribution plans	$ 53	$ 47	$ 34

Note 15 — Capital Structure

For the period from December 31, 2012 to December 31, 2015, 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, 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
Shares issued under ESPP	—	283,139	283,139
Shares issued under LTIPs	1,433,774	—	1,433,774
Share repurchases	—	(24,189,495)	(24,189,495)
Balance as of December 31, 2015	416,939,950	(102,749,908)	314,190,042

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, 2015:

Equity Instrument	Common Stock Reserve Balance
2.822% Convertible perpetual preferred	16,000,000
Long-term incentive plans	17,979,967
Total	33,979,967

Common stock dividends — In 2013, NRG paid quarterly dividends on the Company's common stock of $0.12 per share, or $0.48 per share on an annualized basis. In 2015 and 2014, the Company increased its annual common stock dividend by 4% to $0.58 per share and 17% to $0.56 per share, respectively. The following table lists the dividends paid per common share during 2015, 2014 and 2013:

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2015	$ 0.145	$ 0.145	$ 0.145	$ 0.145
2014	$ 0.140	$ 0.140	$ 0.140	$ 0.120
2013	$ 0.120	$ 0.120	$ 0.120	$ 0.090

On January 18, 2016, NRG declared a quarterly dividend on the Company's common stock of $0.145 per share, or $0.58 per share on an annualized basis, payable on February 16, 2016, to stockholders of record as of February 1, 2016.

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 January 1 and July 1. An exercise date occurs each June 30 and December 31. As of December 31, 2015, there remained 1,276,913 shares of treasury stock reserved for issuance under the ESPP, and in the first quarter of 2016, 299,127 shares of common stock were issued to employee accounts from treasury stock.

Share Repurchases

The Company's board of directors authorized share repurchases of $481 million of its common stock, which were made as follows:

	Total number of shares purchased	Average price paid per share (a)	Amounts paid for shares purchased (in millions) (a)
Board Authorized Share Repurchases			
Fourth Quarter 2014	1,624,360	$ 26.95	$ 44
First Quarter 2015	3,146,484	25.15	79
Second Quarter 2015	4,379,907	24.53	107
Third Quarter 2015	11,104,184	15.06	167
Fourth Quarter 2015	5,558,920	15.03	84
Total Board Authorized Share Repurchases	25,813,855		$ 481

(a) The average price paid per share and amounts paid for shares purchased exclude the commissions of $0.015 per share paid in connection with the share repurchase.

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, were recorded as a dividend on the preferred shares. This amount reduced net income to arrive at net income/(loss) available to NRG common stockholders in the calculation of earnings per share for the year ended December 31, 2014.

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.

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.

The following table reflects the changes in the Company's redeemable preferred stock balance for the years ended December 31, 2015, and 2014.

	(In millions)
Balance as of December 31, 2013	$ 249
Loss recorded in connection with extinguishment of 3.625% preferred stock and issuance of 2.822% preferred stock	42
Balance as of December 31, 2014	291
Accretion to redemption value	11
Balance as of December 31, 2015	$ 302

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 significant equity method investments as of December 31, 2015:

Name	Economic Interest	Investment Balance (in millions)
Avenal Solar Holdings LLC [(a)]	50.0%	$ (9)
Community Wind North, LLC	99.0%	57
Desert Sunlight Investment Holdings, LLC [(a)]	25.0%	291
Elkhorn Ridge Wind, LLC [(a)]	66.7%	96
GenConn Energy LLC [(a)]	50.0%	110
Midway-Sunset Cogeneration Company	50.0%	25
Petra Nova Parish Holdings LLC	50.0%	136
Saguaro Power Company	50.0%	(20)
San Juan Mesa Wind Project, LLC [(a)]	75.0%	80
Sherbino I Wind Farm LLC	50.0%	80
Watson Cogeneration Company	49.0%	36
Gladstone Power Station [(b)]	37.5%	149
Other	Various	14

(a) Equity method investments owned by NRG Yield
(b) Gladstone Power Station is located in Australia

	As of December 31,	
	2015	2014
	(In millions)	
Undistributed earnings from equity investments	$ 55	$ 76

Desert Sunlight — As described in Note 3, *Business Acquisitions and Dispositions*, on June 29, 2015, NRG Yield, Inc., through its subsidiary Yield Operating, acquired 25% of the membership interest in Desert Sunlight Investment Holdings, LLC, which owns two solar photovoltaic facilities that total 550 MW located in Desert Center, California from EFS Desert Sun, LLC, an affiliate of GE Energy Financial Services, for a purchase price of $285 million. The Company accounts for its 25% investment as an equity method investment.

Petra Nova — 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, 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. NRG's 50% interest in the partnership is accounted for as an equity method investment.

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 — 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.

GenConn has 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, 2015, $220 million was outstanding under the note and $14 million was drawn on the working capital facility. The note is secured by all of the GenConn assets. NRG's maximum exposure to loss is limited to its equity investment, which was $110 million as of December 31, 2015.

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 — 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, 2015, the outstanding principal balance of the term loan facility was $87 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 $80 million as of December 31, 2015.

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 $149 million as of December 31, 2015.

Entities that are Consolidated

The Company has a controlling financial interest in certain entities which have been identified as VIEs under ASC 810. These arrangements are primarily related to tax equity arrangements entered into with third-parties in order to finance the cost of solar energy systems under operating leases and wind facilities eligible for certain tax credits as further described in Note 2, *Summary of Significant Accounting Policies*. For one of the tax equity arrangements, the Company has a deficit restoration obligation equal to $23 million as of December 31, 2015, which would be required to be funded if the arrangement were to be dissolved.

The summarized financial information for the Company's consolidated VIEs consisted of the following:

(In millions)	December 31, 2015
Current assets	$ 84
Net property, plant and equipment	1,807
Other long-term assets	863
Total assets	2,754
Current liabilities	56
Long-term debt	366
Other long-term liabilities	179
Total liabilities	601
Noncontrolling interests	493
Net assets less noncontrolling interests	$ 1,660

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, and market stock 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,		
	2015	2014	2013
	(In millions, except per share amounts)		
Basic (loss)/earnings per share attributable to NRG common stockholders			
Net (loss)/income attributable to NRG Energy, Inc.	$ (6,382)	$ 134	$ (386)
Dividends for preferred shares	20	9	9
Dividends for refinancing of preferred shares	—	47	—
(Loss)/Income Available to Common Stockholders	$ (6,402)	$ 78	$ (395)
Weighted average number of common shares outstanding	329	334	323
(Loss)/Earnings per weighted average common share — basic	$ (19.46)	$ 0.23	$ (1.22)
Diluted (loss)/earnings per share attributable to NRG common stockholders			
Weighted average number of common shares outstanding	329	334	323
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	—	5	—
Total dilutive shares	329	339	323
(Loss)/Earnings per weighted average common share — diluted	$ (19.46)	$ 0.23	$ (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,		
	2015	2014	2013
	(In millions of shares)		
Equity compensation	6	1	9
Embedded derivative of 2.822% redeemable perpetual preferred stock[(a)]	16	16	16
Total	22	17	25

(a) At December 31, 2013, the redeemable perpetual preferred stock had an interest rate of 3.625%.

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 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 NRG Yield; NRG Yield and corporate activities. The Company's corporate segment includes BETM, international business and electric vehicle services. Intersegment sales are accounted for at market. NRG Yield includes certain of the Company's contracted generation assets. NRG Yield acquired certain assets from the Company, which were accounted for as transfers of entities under common control and accordingly, all historical periods have been recast to reflect these changes:

- On June 30, 2014, El Segundo Energy Center, formerly in the NRG Business segment, Kansas South and High Desert, both formerly in the NRG Renew segment.
- On January 2, 2015, Walnut Creek, formerly in the NRG Business segment, the Tapestry projects (Buffalo Bear, Pinnacle, and Taloga) and Laredo Ridge, both formerly in the NRG Renew segment.
- On November 3, 2015, 75% of the class B interests in NRG Wind TE Holdco, which owns a portfolio of 12 wind facilities, formerly in the NRG Renew segment.

NRG's chief operating decision maker, its chief executive officer, evaluates the performance of its segments based on operational measures including adjusted earnings before interest, taxes, depreciation and amortization, or Adjusted EBITDA, free cash flow and capital for allocation, as well as net income/(loss) and net income/(loss) attributable to NRG Energy, Inc.

For the years ended December 31, 2015, 2014, and 2013, there were no customers from whom the Company derived more than 10% of the Company's consolidated revenues.

	For the Year Ended December 31, 2015							
		NRG Home						
	NRG Business	Retail	Solar	NRG Renew	NRG Yield	Corporate	Eliminations	Total
	(in millions)							
Operating revenues[(a)]	$ 9,142	$ 5,389	$ 32	$ 474	$ 869	$ (14)	$ (1,218)	$ 14,674
Operating expenses	7,811	4,577	204	218	324	61	(1,220)	11,975
Depreciation and amortization	907	123	25	212	265	34	—	1,566
Impairment charges	4,827	36	132	13	—	—	22	5,030
Acquisition-related transaction and integration costs	—	1	(8)	—	3	14	—	10
Development activity expenses	24	—	—	70	—	60	—	154
Total operating cost and expenses	13,569	4,737	353	513	592	169	(1,198)	18,735
Gain on sale of assets	21	—	—	—	—	—	—	21
Operating (loss)/income	(4,406)	652	(321)	(39)	277	(183)	(20)	(4,040)
Equity in earnings/(losses) of unconsolidated affiliates	7	—	—	1	35	—	(7)	36
Impairment losses on investments	(14)	—	—		—	(42)	—	(56)
Other income, net	40	—	—	4	2	84	(97)	33
Loss on sale of equity-method investment	—	—	—	—	—	(14)	—	(14)
(Loss)/gain on debt extinguishment	—	—	—	—	(9)	84	—	75
Interest expense	(98)	—	(3)	(108)	(238)	(776)	95	(1,128)
(Loss)/income before income taxes	(4,471)	652	(324)	(142)	67	(847)	(29)	(5,094)
Income tax expense/(benefit)	1	—	—	(18)	12	1,347	—	1,342
Net (loss)/income	$ (4,472)	$ 652	$ (324)	$ (124)	$ 55	$ (2,194)	$ (29)	$ (6,436)
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	$ —	$ —	$ (20)	$ 6	$ 19	$ (17)	$ (42)	$ (54)
Net (loss)/income attributable to NRG Energy, Inc.	$ (4,472)	$ 652	$ (304)	$ (130)	$ 36	$ (2,177)	$ 13	$ (6,382)
Balance sheet								
Equity investments in affiliates	185		—	134	798	276	(348)	1,045
Capital expenditures[(b)]	798	30	144	163	30	102	—	1,267
Goodwill	536	340	—	12	—	111	—	999
Total assets	17,139	1,876	413	5,954	7,775	19,576	(19,851)	32,882
(a) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 947	$ 6	$ 1	$ 23	$ 29	$ 212	$ —	$ 1,218

(b) Includes accruals.

	For the Year Ended December 31, 2014							
		NRG Home						
	NRG Business	Retail	Solar	NRG Renew [(d)]	NRG Yield	Corporate	Eliminations[(d)]	Total
	(in millions)							
Operating revenues[(c)]	$ 11,024	$ 5,503	$ 42	$ 427	$ 746	$ 75	$ (1,949)	$ 15,868
Operating expenses	8,894	5,240	108	183	274	72	(1,950)	12,821
Depreciation and amortization	966	122	6	195	202	32	—	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	9,961	5,365	114	452	480	216	(1,972)	14,616
Gain on sale of assets	19	—	—	—	—	—	—	19
Operating income/(loss)	1,082	138	(72)	(25)	266	(141)	23	1,271
Equity in earnings/(losses) of unconsolidated affiliates	23	—	—	(4)	25	3	(9)	38
Other income, net	35	—	—	5	3	78	(99)	22
Gain on sale of equity-method investment	18	—	—	—	—	—	—	18
Loss on debt extinguishment	—	—	—	(1)	—	(94)	—	(95)
Interest expense	(95)	(1)	(1)	(122)	(191)	(806)	97	(1,119)
Income/(loss) before income taxes	1,063	137	(73)	(147)	103	(960)	12	135
Income tax expense/(benefit)	1	—	—	—	4	(2)	—	3
Net income/(loss)	1,062	137	(73)	(147)	99	(958)	12	132
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	—	(19)	2	16	24	(24)	(2)
Net income/(loss) attributable to NRG Energy, Inc.	$ 1,063	$ 137	$ (54)	$ (149)	$ 83	$ (982)	$ 36	$ 134
Balance sheet								
Equity investments in affiliates	$ 141	$ —	$ —	$ 148	$ 410	$ 174	$ (102)	$ 771
Capital expenditures[(e)]	611	34	113	160	13	53	—	984
Goodwill	1,746	387	98	12	—	331	—	2,574
Total assets	$ 28,317	$ 6,049	$ 222	$ 6,481	$ 7,860	$ 30,727	$ (39,190)	$ 40,466
(c) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 1,820	$ 7	$ —	$ 25	$ 12	$ 85	$ —	$ 1,949

(d) 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.
(e) 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[f]	$ 8,638	$ 4,341	$ 4	$ 214	$ 387	$ 19	$ (2,308)	$ 11,295
Operating expenses	7,235	3,814	—	77	155	41	(2,297)	9,025
Depreciation and amortization	930	141	4	86	74	21	—	1,256
Impairment charges	459	—	—	—	—	—	—	459
Acquisition-related transaction and integration costs	—	—	—	—	—	128	—	128
Development activity expenses	14	—	9	34	—	27	—	84
Total operating costs and expenses	8,638	3,955	13	197	229	217	(2,297)	10,952
Operating income/(loss)	—	386	(9)	17	158	(198)	(11)	343
Equity in earnings/of unconsolidated affiliates	(6)	—	—	(7)	22	—	(2)	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)	(2)	—	(52)	(52)	(735)	100	(848)
(Loss)/income before income taxes	(81)	384	(9)	(40)	131	(1,005)	(14)	(634)
Income tax expense/(benefit)	—	—	—	—	8	(290)	—	(282)
Net (loss)/income	(81)	384	(9)	(40)	123	(715)	(14)	(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.	(81)	384	(9)	(62)	110	(729)	1	(386)
(f) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 2,055	$ 5	$ —	$ 14	$ 7	$ 227	$ —	$ 2,308

Note 19 — Income Taxes

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except percentages)		
Current			
State	$ 6	$ 8	$ 11
Total — current	6	8	11
Deferred			
U.S. Federal	1,020	(50)	(207)
State	315	41	(57)
Foreign	1	4	(29)
Total — deferred	1,336	(5)	(293)
Total income tax expense/(benefit)	$ 1,342	$ 3	$ (282)
Effective tax rate	(26.3)%	2.2%	44.5%

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
U.S.	$ (5,105)	$ 126	$ (549)
Foreign	11	9	(85)
Total	$ (5,094)	$ 135	$ (634)

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except percentages)		
(Loss)/Income Before Income Taxes	$ (5,094)	$ 135	$ (634)
Tax at 35%	(1,783)	47	(222)
State taxes	(218)	9	19
Foreign operations	1	1	5
Federal and state tax credits, excluding PTCs	(5)	(1)	(36)
Valuation allowance	3,039	6	(5)
Expiration/utilization of capital losses	—	—	10
Reversal of valuation allowance on expired/utilized capital losses	—	—	(10)
Impact of non-taxable equity earnings	(10)	(11)	(14)
Book goodwill impairment	340	—	—
Net interest accrued on uncertain tax positions	(3)	(2)	(3)
Production tax credit	(33)	(48)	(14)
Recognition of uncertain tax benefits	(15)	(30)	(11)
Tax expense attributable to consolidated partnerships	12	4	8
Impact of change in effective state tax rate	19	22	(21)
Other	(2)	6	12
Income tax expense/(benefit)	$ 1,342	$ 3	$ (282)
Effective income tax rate	(26.3)%	2.2%	44.5%

For the year ended December 31, 2015, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to recording of a valuation allowance on the federal and certain state net deferred tax assets that may not be realizable under a "more likely than not" measurement. In addition, a portion of the book goodwill impairment is classified as a permanent reversal impacting the effective tax rate.

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.

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

	As of December 31,	
	2015	2014
	(In millions)	
Deferred tax liabilities:		
Emissions allowances	$ 31	$ 25
Difference between book and tax basis of property	—	127
Derivatives, net	22	320
Goodwill	—	202
Cumulative translation adjustments	2	8
Investment in projects	838	849
Intangibles amortization (excluding goodwill)	—	99
Other	—	2
Total deferred tax liabilities	893	1,632
Deferred tax assets:		
Deferred compensation, pension, accrued vacation and other reserves	255	266
Discount/premium on notes	68	99
Difference between book and tax basis of property	1,210	—
Goodwill	39	—
Differences between book and tax basis of contracts	516	531
Pension and other postretirement benefits	218	157
Equity compensation	50	77
Bad debt reserve	6	9
U.S. capital loss carryforwards	1	—
U.S. Federal net operating loss carryforwards	1,373	1,523
Foreign net operating loss carryforwards	59	65
State net operating loss carryforwards	230	302
Foreign capital loss carryforwards	1	1
Deferred financing costs	6	23
Federal and state tax credit carryforwards	439	357
Federal benefit on state uncertain tax positions	17	17
Intangibles amortization (excluding goodwill)	90	—
Inventory obsolescence	27	29
Other	11	—
Total deferred tax assets	4,616	3,456
Valuation allowance	(3,575)	(265)
Total deferred tax assets, net of valuation allowance	1,041	3,191
Net deferred tax asset	$ 148	$ 1,559

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

	As of December 31,	
	2015	2014
	(In millions)	
Net deferred tax asset — noncurrent	$ 167	$ 1,580
Net deferred tax liability — noncurrent	(19)	(21)
Net deferred tax asset	$ 148	$ 1,559

Deferred tax assets and valuation allowance

Net deferred tax balance — As of December 31, 2015, and 2014, NRG recorded a net deferred tax asset of $148 million and $1.5 billion, respectively. The Company believes the federal and certain state net deferred tax assets may not be realizable under a "more likely than not" measurement and as such, a valuation allowance has been recorded to reduce the asset accordingly. The Company assesses cumulative and forecasted pretax book earnings, the future reversal of existing taxable temporary differences as well as assumptions and analysis used in assessing certain fixed assets and goodwill impairments during the quarter.

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 $3,575 million and $265 million of tax assets as of December 31, 2015, and 2014, respectively, thus a valuation allowance has been recorded.

NOL carryforwards — At December 31, 2015, the Company had tax effected cumulative domestic NOLs consisting of carryforwards for federal income tax purposes of $1.4 billion and state of $230 million. The Company estimates it will need to generate future taxable income to fully realize the net federal deferred tax asset before expiration commencing in 2026. In addition, NRG has cumulative foreign NOL carryforwards of $59 million with no expiration date.

Valuation allowance — As of December 31, 2015, the Company's tax effected valuation allowance was $3,575 million, consisting of domestic federal net deferred tax assets of approximately $2,973 million, domestic state net deferred tax assets of $542 million, foreign net operating loss carryforwards of $59 million and foreign capital loss carryforwards of approximately $1 million. Based upon the assessment of cumulative and forecasted pretax book earnings, the future reversal of existing taxable temporary differences as well as assumptions and analysis used in assessing certain fixed assets and goodwill impairments, it was determined that a valuation allowance was required to be recorded during the quarter.

Taxes Receivable and Payable

As of December 31, 2015, NRG recorded a current tax payable of $5 million that represents a tax liability due for domestic state taxes. NRG has a domestic tax receivable of $42 million, of which $13 million relates to federal cash grants applied for eligible solar energy projects, net of sequestration. The remaining balance of $29 million is primarily related to current tax refunds due from the New York State Empire Zone program generated in years 2010 through 2014.

Uncertain tax benefits

NRG has identified uncertain tax benefits whose after-tax value is $32 million for which, as of December 31, 2015, and 2014, NRG has recorded a non-current tax liability of $35 million and $53 million, respectively. The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense. During the year ended December 31, 2015, the Company recognized a benefit of $5 million in interest and penalties and accrued interest of $2 million. As of December 31, 2015 and 2014, NRG had cumulative interest and penalties related to these uncertain tax benefits of $3 million and $5 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 2012. 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,	
	2015	2014
	(In millions)	
Balance as of January 1	$ 71	$ 115
Increase due to current year positions	4	—
Increase due to prior year positions	—	10
Decrease due to prior year positions	(25)	(27)
Decrease due to settlements and payments	(18)	(27)
Uncertain tax benefits as of December 31	$ 32	$ 71

Note 20 — Stock-Based Compensation

NRG Energy, Inc. Long-Term Incentive Plan

As of December 31, 2015, and 2014, a total of 22,000,000 shares of NRG common stock were authorized for issuance under the NRG LTIP, and 5,558,390 shares of NRG common stock were authorized for issuance under the NRG GenOn LTIP. The NRG LTIP and the NRG GenOn LTIP are 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 6,240,648 and 6,184,157 shares of common stock remaining available for grants under the NRG LTIP as of December 31, 2015, and 2014, respectively. There were 1,671,633 and 2,150,019 shares of common stock remaining available for grants under the NRG GenOn LTIP as of December 31, 2015, and 2014, respectively.

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 NRG's outstanding NQSOs. No NQSOs were granted in 2015, 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, 2014	2,533,177	$ 30.95	2	$ 9
Forfeited	(59,617)	35.28		
Exercised	(401,647)	23.23		
Outstanding at December 31, 2015	2,071,913	32.27	3	—
Exercisable at December 31, 2015	2,071,913	32.27	3	—

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except for weighted average)		
Total intrinsic value of options exercised	$ 2	$ 7	$ 19
Cash received from options exercised	9	21	33

Restricted Stock Units

As of December 31, 2015, RSUs granted under the Company's LTIPs typically 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, 2014	2,674,626	$ 26.15
Granted	741,351	27.31
Forfeited	(266,802)	27.98
Vested	(887,179)	23.31
Non-vested at December 31, 2015	2,261,996	27.59

The total fair value of RSUs vested during the years ended December 31, 2015, 2014, and 2013, was $10 million, $26 million and $22 million, respectively. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2015, 2014, and 2013 was $27.31, $29.90, and $23.37, respectively. In January 2016, an additional 200,366 restricted stock units were forfeited.

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, 2014	384,663	$ 21.21
Granted	70,929	25.14
Converted to Common Stock	(28,014)	24.78
Outstanding at December 31, 2015	427,578	21.88

The aggregate intrinsic values for DSUs outstanding as of December 31, 2015, 2014, and 2013 were approximately $5 million, $10 million, and $7 million respectively. The aggregate intrinsic values for DSUs converted to common stock for the years ended December 31, 2015, 2014, and 2013 were less than a million, $1 million and $12 million, respectively. The weighted average grant date fair value of DSUs granted during the years ended December 31, 2015, 2014, and 2013 was $25.14, $35.63 and $23.18, 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 the performance period, typically 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, 2014	2,304,569	$ 26.13
Granted	1,108,410	26.68
Vested	(1,230,410)	21.86
Forfeited	(202,412)	29.44
Non-vested at December 31, 2015	1,980,157	29.54

The weighted average grant date fair value of MSUs granted during the years ended December 31, 2015, 2014 and 2013, was $26.68, $31.90 and $27.46, respectively. In January 2016, an additional 1,239,829 market stock units were forfeited due to employee terminations and not meeting performance targets.

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:

	2015	2014
Expected volatility	24.08%-25.20%	23.62%-27.43%
Expected term (in years)	1-3	3-4
Risk free rate	0.25%-1.07%	0.76%-1.21%

For the years ended December 31, 2015, and 2014, 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.

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, 2015, for each of the five types of awards issued under the LTIPs. Minimum tax withholdings of $21 million, $16 million, and $13 million for the years ended December 31, 2015, 2014, and 2013, respectively, are reflected as a reduction to Additional Paid-in Capital on the Company's Consolidated Balance Sheet and are reflected as operating activities on the Company's Consolidated Statement of Cash Flows.

	Compensation Expense			Non-vested Compensation Cost: Unrecognized Total Cost	Non-vested Compensation Cost: Weighted Average Recognition Period Remaining (In years)
	Year Ended December 31			As of December 31	
Award	2015	2014	2013	2015	2015
	(In millions, except weighted average data)				
NQSOs[(a)]	$ —	$ 1	$ 4	$ —	—
RSUs	23	20	18	26	1.79
DSUs	2	2	2	—	—
MSUs	16	19	14	12	1.44
PUs[(a)]	—	—	2	—	—
Total	$ 41	$ 42	$ 40	$ 38	
Tax detriment recognized	$ (12)	$ (8)	$ (6)		

(a) All NQSOs and PUs granted under the Company's LTIP were fully vested as of December 31, 2015.

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,		
	2015	2014	2013
		(In millions)	
Revenues from Related Parties Included in Operating Revenues			
Gladstone	$ 4	$ 6	$ 6
GenConn	4	6	5
Total	$ 8	$ 12	$ 11

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. See further discussion in Note 16, *Investments Accounted for by the Equity Method and Variable Interest Entities.*

Conemaugh and Keystone facilities — The Company operates the Conemaugh and Keystone facilities under five-year agreements that initially expired in December 2015 and were renewed through December 2020 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 $11 million during 2015, $10 million in 2014, and $10 million in 2013.

Note 22 — Commitments and Contingencies

Operating Lease Commitments

Powerton and Joliet Leases

The Company leases 100% interests in the Powerton facility and Unit 7 and Unit 8 of the Joliet facility through 2034 and 2030, 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, 2015, are as follows:

Period	(In millions)
2016	$ 26
2017	1
2018	1
2019	1
2020	1
Thereafter	237
Total	$ 267

GenOn Mid-Atlantic Leases

The Company leases 100% interests 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. 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 is being 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 $43 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, 2015, are as follows:

Period	(In millions)
2016	$ 150
2017	144
2018	105
2019	139
2020	105
Thereafter	442
Total	$ 1,085

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% interests 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. 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 is being 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 $29 million per year through the term of the lease.

In May 2015, NRG mothballed the coal-fired Units 1, 2, 3, and 4 at Shawville generating facility (597 MW) and plans to return those units to service no later than the summer of 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, 2015, are as follows:

Period	**(In millions)**
2016	$ 61
2017	63
2018	55
2019	65
2020	56
Thereafter	278
Total	$ 578

Other Operating Leases

NRG leases certain Company facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2044. NRG also has certain tolling arrangements to purchase power, which qualify 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 $100 million, $106 million, and $88 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2015, are as follows:

Period	**(In millions)**
2016	$ 104
2017	79
2018	72
2019	61
2020	56
Thereafter	410
Total [(a)]	$ 782

(a) Amounts in the table exclude future sublease income of $17 million associated with long-term leases for office locations in 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, 2015, 2014, and 2013, the Company purchased $2.6 billion, $3.5 billion, and $2.8 billion, respectively, under such arrangements.

As of December 31, 2015, the Company's commitments under such outstanding agreements are as follows:

Period	(In millions)	
2016	$	887
2017		295
2018		261
2019		169
2020		174
Thereafter		549
Total	$	2,335

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, 2015. Minimum purchase commitment obligations are as follows as of December 31, 2015:

Period	(In millions)	
2016	$	50
2017		17
2018		2
2019		1
2020		—
Thereafter		—
Total [(a)]	$	70

(a) As of December 31, 2015, 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 and maintains an appropriate ARO. 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 a substantial portion of the Company's assets, excluding assets acquired in the GenOn and EME (including Midwest Generation) acquisitions, assets held by NRG Yield, Inc. and NRG's assets that have project-level financing, 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, 2015, 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 Act. Effective October 22, 2015, the current liability limit per incident is $13.5 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 10, 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 $13.5 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 approximately $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 $13.5 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 $1.25 billion in limits (excess of the first $1.5 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 a NEIL companion policy provides Accidental Outage 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.

Ivanpah Energy Production Guarantee

The Company's PPAs with PG&E with respect to the Ivanpah project contain provisions for contract quantity and guaranteed energy production, which require that Ivanpah units 1 and 3 deliver to PG&E no less than the guaranteed energy production amount specified in the PPAs in any period of twenty-four consecutive months, or performance measurement period, during the term of the PPAs. If either of Ivanpah units 1 and 3 deliver less than the guaranteed energy production amount in any performance measurement period, PG&E may, at its option, declare an event of default. The two units did not meet their guaranteed energy production amount for the initial performance measurement period. On December 18, 2015, PG&E filed a request with the CPUC that it approve, no later than March 31, 2016, forbearance agreements relating to Ivanpah units 1 and 3. Under the forbearance agreements, PG&E agrees to refrain from taking certain actions (including declaring an event of default and invoking associated remedies) for an initial six-month period of time. If the units meet certain production requirements during such period, then the forbearance agreements provide for a six-month extension of such period. On January 15, 2016, three parties submitted protests to the forbearance agreements. On February 16, 2016, the CPUC issued a draft resolution recommending approval of the Forbearance Agreement. The CPUC will vote on the draft resolution no earlier than 30 days after its issuance.

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 for these cases.

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. On December 10, 2015, the District Court granted the Commerzbank Defendants' motion for summary judgment. On December 29, 2015, MC Asset Recovery filed a notice to appeal this ruling. 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.

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 state antitrust law 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 was 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 which reversed the decision of the District Court. 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 and the Supreme Court granted the petition. On April 21, 2015, the Supreme Court affirmed the Ninth Circuit's holding that plaintiffs' state antitrust law claims are not field-preempted by the federal Natural Gas Act and the Supremacy Clause of the U.S. Constitution. The Supreme Court left open whether the claims were preempted on the basis of conflict preemption. The U.S. Supreme Court directed that the case be remanded to the U.S. District Court for the District of Nevada. The case is proceeding in that court. GenOn has agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

In September 2012, the State of Nevada Supreme Court, which was 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 Supreme Court denied the petition for a writ of certiorari, thereby ending one of the five lawsuits.

Energy Plus Holdings — On August 7, 2012, Energy Plus Holdings received a subpoena from the NYAG which generally sought information and business records related to Energy Plus Holdings' sales, marketing and business practices. Energy Plus Holdings provided documents and information to the NYAG. On June 22, 2015, the NYAG issued another subpoena seeking additional information. Energy Plus Holdings is responding to this second subpoena. 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.

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 generating facilities, threatening to sue within 60 days if the generating 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 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.

Potomac River Environmental Investigation — In March 2013, NRG Potomac River LLC received notice that the District of Columbia Department of Environment (now renamed the Department of Energy and Environment, or DOEE) was investigating potential discharges to the Potomac River originating from the Potomac River Generating facility site, a site where the generation facility is no longer in operation. In connection with that investigation, DOEE served a civil subpoena on NRG Potomac River LLC requesting information related to the site and potential discharges occurring from the site. NRG Potomac River LLC provided various responsive materials. In January 2016, DOEE advised NRG Potomac River that DOEE believed various environmental violations had occurred as a result of discharges DOEE believes occurred to the Potomac River from the Potomac River Generating facility site and as a result of associated failures to accurately or sufficiently report such discharges. DOEE has indicated it believes that penalties are appropriate in light of the violations. NRG is currently reviewing the information provided by DOEE.

Telephone Consumer Protection Act Purported Class Actions — Three purported class action lawsuits have been filed against NRG Residential Solar Solutions, LLC, one in California and two in New Jersey. The plaintiffs generally allege misrepresentation by the call agents and violations of the TCPA, claiming that the defendants engaged in a telemarketing campaign placing unsolicited calls to individuals on the "Do Not Call List." The plaintiffs seek statutory damages of up to $1,500 per plaintiff, actual damages and equitable relief. The Company is vigorously defending against these lawsuits. NRG requested and was granted a stay in the California case and one of the New Jersey cases pending a decision of an unrelated case by the U.S. Supreme Court, the results of which could materially affect these lawsuits.

El Segundo Environmental Liability — During the maintenance of breakers in 2012, the Company's El Segundo plant exceeded California's limit regarding SF6 losses. SF6 is an electrical insulator and GHG. On December 16, 2015, the Company entered into a settlement agreement with the California Air Resources Board thereby resolving the matter. Pursuant to the settlement agreement, the Company agreed to pay a penalty of $150,000 plus an additional $50,000 directed to clean air/clear air funding for a community college system.

California Department of Water Resources and San Diego Gas & Electric Company v. Sunrise Power Company LLC — On January 29, 2016, CDWR and SDG&E filed a lawsuit against Sunrise Power Company, along with NRG and Chevron Power Corporation. In June 2001, CDWR and Sunrise entered into a 10-year PPA under which Sunrise would construct and operate a generating facility and provide power to CDWR. At the time the PPA was entered into, Sunrise had a transportation services agreement, or TSA, to purchase natural gas from Kern River through April 30, 2018. In August 2003, CDWR entered into an agreement with Sunrise and Kern River in which CDWR accepted assignment of the TSA through the term of the PPA. After the PPA expired, Kern River demanded that any reassignment be to a party which met certain creditworthiness standards which Sunrise did not. As such, the plaintiffs have brought this lawsuit against the defendants alleging breach of contract, breach of covenant of good faith and fair dealing and improper distributions. Plaintiffs generally claim damages of $1.2 million per month for the remaining 70 months of the TSA.

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 parties 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

U.S. Supreme Court Agrees to Consider the Constitutionality of Maryland's Generator Contracting Programs — On October 19, 2015, the U.S. Supreme Court agreed to hear a case challenging the constitutionality of certain state-directed procurements of new electric generating facilities. The case involves the authority of the Maryland Public Service Commission to direct load-serving utilities in the state to enter into long-term power purchase contracts with a generation developer to encourage the construction of new generation capacity in Maryland. The constitutionality of the long-term contracts was challenged in the U.S. District Court for the District of Maryland, which, in an October 24, 2013, decision, found that the contracts violated the Supremacy Clause of the U.S. Constitution because they were both conflict preempted and field preempted by the FPA and the authority that the FPA granted to FERC. On June 30, 2014, the U.S. Court of Appeals for the Fourth Circuit affirmed the District Court's decision. A case arising out of New Jersey and raising similar issues was decided by the U.S. Court of Appeals for the Third Circuit, which also determined that the state-mandated contracts were preempted. After the Supreme Court granted certiorari in the Maryland case, the Company filed a friend-of-the-court brief urging the Court to uphold the right of states to incentivize new generation by directing utilities in the state to enter into long-term contracts — but noted that FERC has both the authority and the statutory obligation to protect wholesale markets by requiring that bids in the wholesale markets reflect costs and by ensuring that uneconomic entry does not distort auction outcomes. The Supreme Court heard oral argument on February 24, 2016. The outcome of this litigation could have broad impacts on whether and how states require utilities to contract with new generation resources, as well as how such contracted resources interact with the FERC-jurisdictional wholesale markets.

U.S. Supreme Court Allows FERC to Retain Jurisdiction Over Demand Response — On January 25, 2016, the U.S. Supreme Court issued a 6-2 decision affirming FERC's ability to exercise jurisdiction over demand response resources seeking to voluntarily participate in the wholesale markets. Additionally, the Supreme Court upheld FERC's preferred scheme for pricing demand response in the energy market. This case arose out of a May 23, 2014, decision by the D.C. Circuit which vacated FERC's rules (known as Order No. 745) that set the compensation level for demand response resources participating in the FERC-jurisdictional energy markets. The Court of Appeals had held that the FPA 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. With the Supreme Court's decision, FERC will resume exercising jurisdiction over demand response, which the Company views as a positive for both its wholesale and distributed businesses.

East Region

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 disputed the applicability of the tax. On December 11, 2015, the Maryland Tax Court reversed Montgomery County's assessment. Montgomery County has filed an appeal.

Retail

MISO SECA — Green Mountain Energy previously provided competitive retail energy supply in the MISO region during the 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 eliminate seams charges and in the meantime, as a temporary measure, allowed them to recover transition charges known as SECA charges. 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. On September 16, 2015, FERC issued an order conditionally accepting those compliance filings, and setting for hearing and settlement proceedings issues related to service to certain Michigan customers during 2002 and 2003.

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

Carlsbad Energy Center — On May 21, 2015, the CPUC approved the Carlsbad Energy Center PPTA for a nominally rated 500 MW five unit natural gas peaking plant. On December 7, 2015, three parties filed two petitions for a writ of review with the California Court of Appeal appealing the CPUC's decision. The petitions remain pending. Additionally, on July 30, 2015, the CEC approved an amendment to the design of the Carlsbad Energy Center. On September 22, 2015, the CEC granted rehearing of its decision approving the amendment to permit the California Department of Fish and Wildlife, or CDFW, to file comments on the proposed decision. On November 12, 2015, the CEC issued an order on rehearing affirming its decision approving the amendment. No party appealed the CEC's decision.

California Station Power — As the result of unfavorable final and non-appealable litigation, the Company has accrued a liability associated with its power plants' consumption of station power in California, after August 30, 2010. The majority of the liability is associated with the Company's Encina, El Segundo, and Long Beach facilities. The Company has established an appropriate reserve and is awaiting final billing decisions from SCE.

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. NRG is also subject to laws regarding the protection of wildlife, including migratory birds, eagles and threatened and endangered species. Environmental laws have become increasingly stringent and NRG expects this trend to continue. The electric generation industry is facing new requirements regarding GHGs, 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, to address certain states' obligation to reduce emissions so that downwind states can achieve federal air quality standards. In December 2011, the D.C. Circuit stayed the implementation of CSAPR and then vacated CSAPR in August 2012 but kept CAIR in place until the EPA could replace it. In April 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 in November 2014 amended the CSAPR compliance dates. Accordingly, CSAPR replaced CAIR on January 1, 2015. On July 28, 2015, the D.C. Circuit held that the EPA had exceeded its authority by requiring certain reductions that were not necessary for downwind states to achieve federal standards. Although the D.C. Circuit kept the rule in place, the court ordered the EPA to revise the Phase 2 (or 2017) (i) SO_2 budgets for four states including Texas and (ii) ozone-season NO_x budgets for 11 states including Maryland, New Jersey, New York, Ohio, Pennsylvania and Texas. The EPA is currently reviewing the decision. In December 2015, the EPA proposed the CSAPR Update Rule using the 2008 Ozone NAAQS, which would reduce the total amount of ozone season NO_x as compared with the previously utilized 1997 Ozone NAAQS. If finalized, this proposal would reduce future NO_x allocations and/or current banked allowances. While NRG cannot predict the final outcome of this rulemaking, the Company believes its investment in pollution controls and cleaner technologies leave the fleet well-positioned for compliance.

In February 2012, the EPA promulgated standards (the MATS rule) 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 had to be met beginning in April 2015 (with some units getting a 1-year extension). In June 2015, the U.S. Supreme Court issued a decision in the case of *Michigan v. EPA*, and held that the EPA unreasonably refused to consider costs when it determined that it was "appropriate and necessary" to regulate HAPs emitted by electric generating units. The U.S. Supreme Court did not vacate the MATS rule but rather remanded it to the D.C. Circuit for further proceedings. In November 2015, the EPA proposed a supplemental finding that including a consideration of cost does not alter the EPA's previous determination that it is appropriate and necessary to regulate air toxics, including mercury from power plants. In December 2015, the D.C. Circuit remanded the rule to the EPA without vacatur. While NRG cannot predict the final outcome of this rulemaking, NRG believes that because it has already invested in pollution controls and cleaner technologies, the fleet is well-positioned to comply with the MATS rule.

Water

In August 2014, the EPA finalized the regulation regarding the use of water for once through cooling at 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 as NPDES permits are renewed.

Byproducts, Wastes, Hazardous Materials and Contamination

In April 2015, the EPA finalized the rule regulating byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. The Company has evaluated the impact of the new rule on its results of operations, financial condition and cash flows and has accrued its environmental and asset retirement obligations under the rule based on current estimates as of December 31, 2015.

East Region

Maryland Environmental Regulations — In December 2014, MDE proposed a regulation regarding NO_x emissions from coal-fired electric generating units, which had it been finalized would have required by 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 either (1) install and operate an SCR; (2) retire the unit; or (3) convert the fuel source from coal to natural gas. In early 2015, the State of Maryland decided not to finalize the regulation as proposed. In November 2015, MDE finalized revised regulations to address future NO_x reductions, which although more stringent than previous regulations, will not cause the Company to spend capital to comply. As a result of the new regulations, on February 29, 2016, NRG notified PJM that it was withdrawing the standing deactivation notices for Dickerson Units 1, 2 and 3 and Chalk Point Units 1 and 2.

New Source Review — 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.

Burton Island Old Ash Landfill — 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

NRG estimates that environmental capital expenditures from 2016 through 2020 required to comply with environmental laws will be approximately $350 million, which includes $68 million for GenOn and $263 million for Midwest Generation. These costs, the majority of which will be expended by the end of 2016, are primarily associated with (i) DSI/ESP upgrades at the Powerton facility and the Joliet gas conversion to satisfy the IL CPS and (ii) MATS compliance at the Avon Lake facility.

Note 25 — Cash Flow Information

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

	Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Interest paid, net of amount capitalized	$ 1,172	$ 1,067	$ 836
Income taxes (refunded)/paid [(a)]	16	(6)	(60)
Consent fee paid, preferred stock	—	5	—
Non-cash investing and financing activities:			
(Decrease)/additions to fixed assets for accrued capital expenditures	(24)	87	405
Decrease to fixed assets for accrued grants and related tax impact	—	(711)	(681)
Issuance of shares for EME acquisition	—	(401)	—

(a) In 2015, the net income taxes paid reflect $17 million in income taxes paid and $1 million in income tax refunds. 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.

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 $3.6 million as of December 31, 2015, 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,					
	2015					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2014 Total
			(In millions)			
Letters of credit and surety bonds	$ 1,805	$ 92	$ —	$ 2	$ 1,899	$ 1,914
Asset sales guarantee obligations	—	—	257	—	257	292
Other guarantees	—	1	—	721	722	1,174
Total guarantees	$ 1,805	$ 93	$ 257	$ 723	$ 2,878	$ 3,380

Letters of credit and surety bonds — As of December 31, 2015, 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.

The material indemnities, within the scope of ASC 460, are as follows:

Asset sales — 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.

Other guarantees — NRG has issued other guarantees of obligations including payments under certain agreements with respect to certain of its unconsolidated subsidiaries, payment or performance by fuel providers and payment or reimbursement of credit support and deposits. 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, 2015	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%	$ 3,246	$ (1,599)	$ 38
Big Cajun II Unit 3, New Roads, LA	58.00%	206	(114)	—
Cedar Bayou Unit 4, Baytown, TX	50.00%	211	(57)	—
Keystone, Shelocta, PA	3.70%	97	(44)	—
Conemaugh, New Florence, PA	3.72%	101	(46)	1

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			
	2015			
	December 31	September 30	June 30	March 31
	(In millions, except per share data)			
Operating revenues	$ 3,011	$ 4,434	$ 3,400	$ 3,829
Operating (loss)/income	(4,727)	379	232	76
Net (loss)/income	(6,358)	67	(9)	(136)
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(44)	1	5	(16)
Net (loss)/income attributable to NRG Energy, Inc.	(6,314)	66	(14)	(120)
(Loss)/income available to Common Stockholders	$ (6,319)	$ 61	$ (19)	$ (125)
Weighted average number of common shares outstanding — basic	315	331	333	336
Net (loss)/income per weighted average common share — basic	$ (20.08)	$ 0.18	$ (0.06)	$ (0.37)
Weighted average number of common shares outstanding — diluted	315	332	333	336
Net (loss)/income per weighted average common share — diluted	$ (20.08)	$ 0.18	$ (0.06)	$ (0.37)

	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)
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	(22)	14	17	(11)
Net income/(loss) attributable to NRG Energy, Inc.	119	168	(97)	(56)
Income/(loss) available to Common Stockholders	$ 70	$ 166	$ (100)	$ (58)
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)

Note 29 — Condensed Consolidating Financial Information

As of December 31, 2015, the Company had outstanding \$6.2 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, and NRG Yield , Inc. and its subsidiaries

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 31, 2015:

Ace Energy, Inc.
Allied Warranty LLC
Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Bayou Cove Peaking Power LLC
BidURenergy, Inc.
Cabrillo Power I LLC
Cabrillo Power II LLC
Carbon Management Solutions LLC
Cirro Group, Inc.
Cirro Energy Services, Inc.
Clean Edge Energy LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Cottonwood Development LLC
Cottonwood Energy Company LP
Cottonwood Generating Partners I LLC
Cottonwood Generating Partners II LLC
Cottonwood Generating Partners III LLC
Cottonwood Technology Partners LP
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company LLC
El Segundo Power, LLC
El Segundo Power II LLC
Energy Alternatives Wholesale, LLC
Energy Choice Solutions, LLC
NRG Curtailment Solutions, Inc.
Energy Plus Holdings LLC
Energy Plus Natural Gas LLC
Energy Protection Insurance Company
Everything Energy LLC
Forward Home Security, LLC
GCP Funding Company, LLC
Green Mountain Energy Company
Gregory Partners, LLC
Gregory Power Partners LLC
Huntley Power LLC
Independence Energy Alliance LLC
Independence Energy Group LLC
Independence Energy Natural Gas LLC
Indian River Operations Inc.
Indian River Power LLC
Keystone Power LLC
Langford Wind Power LLC
NRG Home Services LLC
Louisiana Generating LLC
Meriden Gas Turbines LLC
Middletown Power LLC
Montville Power LLC
NEO Corporation
NRG Business Services LLC
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP, LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Artesian Energy LLC
NRG Arthur Kill Operations Inc.
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Business Solutions LLC
NRG Cabrillo Power Operations Inc.
NRG California Peaker Operations LLC
NRG Cedar Bayou Development Company, LLC
NRG Connected Home LLC
NRG Connecticut Affiliate Services Inc.
NRG Construction LLC
NRG Curtailment Solutions LLC
NRG Development Company Inc.
NRG Devon Operations Inc.
NRG Dispatch Services LLC
NRG Distributed Generation PR LLC
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Energy Efficiency-L LLC
NRG Energy Efficiency-P LLC
NRG Energy Labor Services LLC
NRG ECOKAP Holdings, LLC
NRG Energy Services Group LLC
NRG Energy Services International Inc.
NRG Energy Services LLC
NRG Generation Holdings, Inc.
NRG Home & Business Solutions LLC
NRG Home Solutions LLC
NRG Home Solutions Product LLC
NRG Homer City Services LLC
NRG Huntley Operations Inc.
NRG HQ DG LLC
NRG Identity Protect LLC
NRG Ilion Limited Partnership
NRG Ilion LP LLC
NRG International LLC
NRG Maintenance Services LLC
NRG Mextrans Inc.
NRG MidAtlantic Affiliate Services Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG GreenCo, LLC
NRG GreenCo Holdings, LLC
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG PacGen Inc.
NRG Portable Power LLC
NRG Power Marketing LLC
NRG Reliability Solutions LLC
NRG Renter's Protection LLC
NRG Retail LLC
NRG Retail Northeast LLC
NRG Rockford Acquisition LLC
NRG Saguaro Operations Inc.
NRG Security LLC
NRG Services Corporation
NRG SimplySmart Solutions LLC
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG Texas C&I Supply LLC
NRG Texas Gregory LLC
NRG Texas Holding Inc.
NRG Texas LLC
NRG Texas Power LLC
NRG Warranty Services LLC
NRG West Coast LLC
NRG Western Affiliate Services Inc.
O'Brien Cogeneration, Inc. II
ONSITE Energy, Inc.
Oswego Harbor Power LLC
RE Retail Receivables, LLC
Reliant Energy Northeast LLC
Reliant Energy Power Supply, LLC
Reliant Energy Retail Holdings, LLC
Reliant Energy Retail Services, LLC
RERH Holdings LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services, LLC
Texas Genco Services, LP
US Retailers LLC
Vienna Operations Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries, including GenOn and its subsidiaries. NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company's ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG's ability to receive funds from its subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under the Company's Peaker financing agreements, there are no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to NRG. In addition, there may be restrictions for certain non-guarantor subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities.

In this presentation, NRG Energy, Inc. consists of parent company operations. Guarantor subsidiaries and non-guarantor subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

In addition, the condensed parent company financial statements are provided in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of NRG Energy, Inc.'s subsidiaries exceed 25 percent of the consolidated net assets of NRG Energy, Inc. These statements should be read in conjunction with the consolidated statements and notes thereto of NRG Energy, Inc. For a discussion of NRG Energy, Inc.'s long-term debt, see Note 12, *Debt and Capital Leases* to the consolidated financial statements. For a discussion of NRG Energy, Inc.'s contingencies, see Note 22, *Commitments and Contingencies* to the consolidated financial statements. For a discussion of NRG Energy, Inc.'s guarantees, see Note 26, *Guarantees* to the consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2015

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
			(In millions)		
Operating Revenues					
Total operating revenues	$ 10,024	$ 4,768	$ —	$ (118)	$ 14,674
Operating Costs and Expenses					
Cost of operations	7,712	3,147	14	(118)	10,755
Depreciation and amortization	787	759	20	—	1,566
Impairment losses	4,655	375	—	—	5,030
Selling, general and administrative	467	403	350	—	1,220
Acquisition-related transaction and integration costs	1	(5)	14	—	10
Development activity expenses	—	61	93	—	154
Total operating costs and expenses	13,622	4,740	491	(118)	18,735
Gain on postretirement benefits curtailment	—	21	—	—	21
Operating (Loss)/Income	(3,598)	49	(491)	—	(4,040)
Other Income/(Expense)					
Equity in losses of consolidated subsidiaries	(86)	(29)	(2,799)	2,914	—
Equity in earnings of unconsolidated affiliates	8	37	—	(9)	36
Impairment charge on investment	—	(25)	(31)	—	(56)
Other income, net	4	29	—	—	33
Loss on sale of equity-method investment	—	—	(14)	—	(14)
Net gain on debt extinguishment	—	56	19	—	75
Interest expense	(18)	(564)	(546)	—	(1,128)
Total other expense	(92)	(496)	(3,371)	2,905	(1,054)
Loss Before Income Taxes	(3,690)	(447)	(3,862)	2,905	(5,094)
Income tax (benefit)/expense	(1,104)	(96)	2,489	53	1,342
Net Loss	(2,586)	(351)	(6,351)	2,852	(6,436)
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	—	(23)	31	(62)	(54)
Net Loss Attributable to NRG Energy, Inc.	$ (2,586)	$ (328)	$ (6,382)	$ 2,914	$ (6,382)

(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, 2015

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
			(In millions)		
Net Loss	$ (2,586)	$ (351)	$ (6,351)	$ 2,852	$ (6,436)
Other Comprehensive (Loss)/Income, net of tax					
Unrealized (loss)/gain on derivatives, net	(9)	(13)	48	(41)	(15)
Foreign currency translation adjustments, net	—	(7)	(4)	—	(11)
Available-for-sale securities, net	—	(1)	18	—	17
Defined benefit plan, net	(22)	(15)	47	—	10
Other comprehensive (loss)/income	(31)	(36)	109	(41)	1
Comprehensive Loss	(2,617)	(387)	(6,242)	2,811	(6,435)
Less: Comprehensive (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	—	(42)	31	(62)	(73)
Comprehensive Loss Attributable to NRG Energy, Inc.	(2,617)	(345)	(6,273)	2,873	(6,362)
Dividends for preferred shares	—	—	20	—	20
Comprehensive Loss Available for Common Stockholders	$ (2,617)	$ (345)	$ (6,293)	$ 2,873	$ (6,382)

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2015

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
			(In millions)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ —	$ 825	$ 693	$ —	$ 1,518
Funds deposited by counterparties	55	51	—	—	106
Restricted cash	5	409	—	—	414
Accounts receivable - trade, net	851	304	2	—	1,157
Accounts receivable - Affiliate	395	260	571	(1,222)	4
Inventory	570	682	—	—	1,252
Derivative instruments	1,202	871	—	(158)	1,915
Cash collateral paid in support of energy risk management activities	474	94	—	—	568
Renewable energy grant receivable	—	13	—	—	13
Current assets held-for-sale	—	6	—	—	6
Prepayments and other current assets	93	274	71	—	438
Total current assets	3,645	3,789	1,337	(1,380)	7,391
Net Property, Plant and Equipment	4,767	13,773	219	(27)	18,732
Other Assets					
Investment in subsidiaries	842	2,244	11,039	(14,125)	—
Equity investments in affiliates	(14)	1,160	1	(102)	1,045
Notes receivable, less current portion	—	46	7	—	53
Goodwill	697	302	—	—	999
Intangible assets, net	763	1,551	2	(6)	2,310
Nuclear decommissioning trust fund	561	—	—	—	561
Deferred income taxes	(6)	815	(642)	—	167
Derivative instruments	153	184	—	(32)	305
Non-current assets held for sale	—	105	—	—	105
Other non-current assets	80	749	385	—	1,214
Total other assets	3,076	7,156	10,792	(14,265)	6,759
Total Assets	$ 11,488	$ 24,718	$ 12,348	$ (15,672)	$ 32,882
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 2	$ 460	$ 19	$ —	$ 481
Accounts payable	553	277	39	—	869
Accounts payable - affiliate	151	2,000	(929)	(1,222)	—
Derivative instruments	1,130	749	—	(158)	1,721
Cash collateral received in support of energy risk management activities	55	51	—	—	106
Accrued interest expense	5	91	147	(1)	242
Other accrued expenses	122	151	295	—	568
Current liabilities held-for-sale	—	2	—	—	2
Other current liabilities	192	187	7	—	386
Total current liabilities	2,210	3,968	(422)	(1,381)	4,375
Other Liabilities					
Long-term debt and capital leases	302	10,496	8,185	—	18,983
Nuclear decommissioning reserve	326	—	—	—	326
Nuclear decommissioning trust liability	283	—	—	—	283
Postretirement and other benefit obligations	236	200	152	—	588
Deferred income taxes	179	(1,088)	928	—	19
Derivative instruments	301	224	—	(32)	493
Out-of-market contracts	95	1,051	—	—	1,146
Non-current liabilities held-for-sale	—	4	—	—	4
Other non-current liabilities	318	535	47	—	900
Total non-current liabilities	2,040	11,422	9,312	(32)	22,742
Total Liabilities	4,250	15,390	8,890	(1,413)	27,117
2.822% Preferred Stock	—	—	302	—	302
Redeemable noncontrolling interest in subsidiaries	—	29	—	—	29
Stockholders' Equity	7,238	9,299	3,156	(14,259)	5,434
Total Liabilities and Stockholders' Equity	$ 11,488	$ 24,718	$ 12,348	$ (15,672)	$ 32,882

(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, 2015

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net Loss	(2,586)	(351)	(6,351)	2,852	(6,436)
Adjustments to reconcile net loss to net cash provided by operating activities:					
Distributions from unconsolidated affiliates	3	91	—	(21)	73
Equity in losses of unconsolidated affiliates	(8)	(37)	—	9	(36)
Depreciation and amortization	787	759	20	—	1,566
Provision for bad debts	58	3	3	—	64
Amortization of nuclear fuel	45	—	—	—	45
Amortization of financing costs and debt discount/premiums	—	(37)	26	—	(11)
Adjustment to gain on debt extinguishment	—	(56)	(19)	—	(75)
Amortization of intangibles and out-of-market contracts	52	29	—	—	81
Amortization of unearned equity compensation	—	—	41	—	41
Gain on post retirement benefits curtailment and sales of assets	—	(21)	14	—	(7)
Impairment losses	4,655	400	31	—	5,086
Changes in derivative instruments	264	(31)	—	—	233
Changes in collateral deposits supporting energy risk management activities	(360)	(21)	—	—	(381)
Changes in deferred income taxes and liability for uncertain tax benefits	(1,092)	(237)	2,655	—	1,326
Changes in nuclear decommissioning trust liability	(2)	—	—	—	(2)
Cash used by changes in other working capital	(8,744)	(950)	12,276	(2,840)	(258)
Net Cash (Used)/Provided by Operating Activities	(6,928)	(459)	8,696	—	1,309
Cash Flows from Investing Activities					
Proceeds from intercompany loans to subsidiaries	7,183	1,258	—	(8,441)	—
Acquisition of 2015 Drop Down Assets, net of cash acquired	—	(698)	—	698	—
Acquisition of businesses, net of cash acquired	—	(31)	—	—	(31)
Capital expenditures	(316)	(908)	(59)	—	(1,283)
(Increase)/decrease in restricted cash, net	(1)	9	—	—	8
Decrease in restricted cash - U.S. DOE projects	—	34	1	—	35
Decrease in notes receivable	—	18	—	—	18
Proceeds from renewable energy grants	—	82	—	—	82
Purchases of emission allowances, net of proceeds	41	—	—	—	41
Investments in nuclear decommissioning trust securities	(629)	—	—	—	(629)
Proceeds from sales of nuclear decommissioning trust fund securities	631	—	—	—	631
Proceeds from sale of assets, net	—	1	26	—	27
Investments in unconsolidated affiliates	1	(357)	(39)	—	(395)
Other	—	11	—	—	11
Net Cash Provided/(Used) by Investing Activities	6,910	(581)	(71)	(7,743)	(1,485)
Cash Flows from Financing Activities					
Payments from intercompany loans	—	—	(8,441)	8,441	—
Acquisition of 2015 Drop Down Assets, net of cash acquired	—	—	698	(698)	—
Payment of dividends to preferred and common stockholders	—	—	(201)	—	(201)
Net receipts from settlement of acquired derivatives that include financing elements	—	196	—	—	196
Payment for treasury stock	—	—	(437)	—	(437)
Sale proceeds and other contributions from noncontrolling interests in subsidiaries	—	647	—	—	647
Proceeds from issuance of common stock	—	—	1	—	1
Proceeds from issuance of long-term debt	—	953	51	—	1,004
Payment of debt issuance and hedging costs	—	(21)	—	—	(21)
Payments for short and long-term debt	—	(1,353)	(246)	—	(1,599)
Other	—	(22)	—	—	(22)
Net Cash (Used)/Provided by Financing Activities	—	400	(8,575)	7,743	(432)
Effect of exchange rate changes on cash and cash equivalents	—	10	—	—	10
Net (Decrease)/Increase in Cash and Cash Equivalents	(18)	(630)	50	—	(598)
Cash and Cash Equivalents at Beginning of Period	18	1,455	643	—	2,116
Cash and Cash Equivalents at End of Period	$ —	$ 825	$ 693	$ —	$ 1,518

(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, 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	4,206	4	(325)	11,794
Depreciation and amortization	801	706	16	—	1,523
Impairment losses	—	119	—	(22)	97
Selling, general and administrative	333	390	304	—	1,027
Acquisition-related transactions and integration costs	3	15	66	—	84
Development activity expense	—	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
Impairment losses on investments	—	—	—	—	—
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/(Loss) 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 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.

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.

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
Cash collateral paid in support of energy risk management activities	114	73	—	—	187
Accounts receivable - affiliate	7,449	1,988	(5,991)	(3,437)	9
Renewable energy grant receivable	—	134	1	—	135
Prepayments and other current assets	94	269	75	—	438
Total current assets	10,807	6,744	(5,265)	(3,878)	8,408
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
Derivative instruments	242	288	1	(51)	480
Deferred income taxes	(247)	722	1,105	—	1,580
Non-current assets held for sale	—	17	—	—	17
Other non-current assets	108	520	417	—	1,045
Total other assets	3,497	7,250	25,044	(26,100)	9,691
Total Assets	$ 22,648	$ 27,871	$ 19,950	$ (30,003)	$ 40,466
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
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	4,011	4,831	(7)	(3,976)	4,859
Other Liabilities					
Long-term debt and capital leases	302	11,123	8,276	—	19,701
Nuclear decommissioning reserve	310	—	—	—	310
Nuclear decommissioning trust liability	333	—	—	—	333
Postretirement and other benefit obligations	277	234	216	—	727
Deferred income taxes	1,043	(1,012)	(10)	—	21
Derivative instruments	248	241	—	(51)	438
Out-of-market commodity contracts	111	1,133	—	—	1,244
Other non-current liabilities	188	561	98	—	847
Total non-current liabilities	2,812	12,280	8,580	(51)	23,621
Total Liabilities	6,823	17,111	8,573	(4,027)	28,480
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	$ 22,648	$ 27,871	$ 19,950	$ (30,003)	$ 40,466

(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 Income	924	426	149	(1,367)	132
Adjustments to reconcile net loss to net cash provided by operating activities:					
Distributions from unconsolidated affiliates	—	87	—	—	87
Equity in losses of unconsolidated affiliates	(13)	(33)	—	8	(38)
Depreciation and amortization	801	706	16	—	1,523
Provision for bad debts	64	—	—	—	64
Amortization of nuclear fuel	46	—	—	—	46
Amortization of financing costs and debt discount/premiums	—	(40)	28	—	(12)
Adjustment to loss on debt extinguishment	—	8	17	—	25
Amortization of intangibles and out-of-market contracts	65	(1)	—	—	64
Amortization of unearned equity compensation	—	—	42	—	42
Gain on sale of assets, net	—	(4)	—	—	(4)
Impairment losses	—	119	—	(22)	97
Changes in derivative instruments	(149)	88	—	—	(61)
Changes in deferred income taxes and liability for uncertain tax benefits	242	(115)	(281)	—	(154)
Changes in nuclear decommissioning trust liability	19	—	—	—	19
Cash used by changes in other working capital	787	(973)	(4,723)	4,589	(320)
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)
Decrease in restricted cash, net	—	57	—	—	57
(Increase) 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, net of proceeds	(16)	—	—	—	(16)
Investments in nuclear decommissioning trust fund securities	(619)	—	—	—	(619)
Proceeds from sales 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 from intercompany loans	—	—	3,208	(3,208)	—
Payment of dividends to preferred stockholders	—	—	(196)	—	(196)
Net receipts from acquired derivatives that include financing elements	—	9	—	—	9
Payment for treasury stock	—	—	(39)	—	(39)
Sales proceeds from sale of noncontrolling interest in subsidiaries	—	819	—	—	819
Proceeds from issuance of common stock	—	—	21	—	21
Proceeds from issuance of long-term debt	—	1,182	3,381	—	4,563
Payment of debt issuance and hedging costs	—	(39)	(28)	—	(67)
Payments of 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.	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	2,113	—	(133)	8,130
Depreciation and amortization	837	407	12	—	1,256
Impairment losses	459	—	—	—	459
Selling, general and administrative	446	221	234	(6)	895
Acquisition-related transaction and integration costs	—	70	58	—	128
Development activity expenses	—	34	50	—	84
Total operating costs and expenses	7,892	2,845	354	(139)	10,952
Operating Income/(Loss)	331	366	(354)	—	343
Other (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 losses on investment	—	(99)	—	—	(99)
Other income/(loss), 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 interest	—	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
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)/income 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 interest	—	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 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 Income/(Loss)	121	45	(372)	(146)	(352)
Adjustments to reconcile net loss to net cash provided by operating activities:					
Distributions from unconsolidated affiliates	51	26	—	—	77
Equity in losses of unconsolidated affiliates	11	(22)	—	4	(7)
Depreciation and amortization	837	407	12	—	1,256
Provision for bad debts	67	—	—	—	67
Amortization of nuclear fuel	36	—	—	—	36
Amortization of financing costs and debt discount/premiums	—	(9)	(24)	—	(33)
Adjustment for debt extinguishment	—	(27)	12	—	(15)
Amortization of intangibles and out-of-market contracts	100	(51)	—	—	49
Amortization of unearned equity compensation	—	—	38	—	38
Gain on sale of assets, net	—	(3)	—	—	(3)
Impairment losses	459	99	—	—	558
Changes in derivative instruments	197	(33)	—	—	164
Changes in deferred income taxes and liability for uncertain tax benefits	(58)	292	(301)	—	(67)
Changes in nuclear decommissioning trust liability	15	—	—	—	15
Cash used by changes in other working capital	482	(941)	(1,911)	1,857	(513)
Net Cash Provided/(Used) by Operating Activities	2,318	(217)	(2,546)	1,715	1,270
Cash Flows from Investing Activities					
Intercompany loans to subsidiaries	(1,722)	7	1,715	—	—
Acquisition of business, net of cash acquired	—	(179)	(315)	—	(494)
Capital expenditures	(528)	(1,413)	(46)	—	(1,987)
(Increase)/decrease in restricted cash	(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 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 for dividends to preferred stockholders	—	—	(154)	—	(154)
Net (payments for)/receipts from acquired derivatives that include financing elements	(79)	346	—	—	267
Payment for treasury stock	—	—	(25)	—	(25)
Sales proceeds from sale of noncontrolling interest in subsidiary	—	531	—	—	531
Proceeds from issuance of common stock	—	—	16	—	16
Proceeds from issuance of long-term debt	—	1,292	485	—	1,777
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 Increase/(Decrease) 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.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2015, 2014, and 2013

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(In millions)		
Allowance for doubtful accounts, deducted from accounts receivable					
Year Ended December 31, 2015	$ 23	$ 62	$ —	$ (64) [(a)]	21
Year Ended December 31, 2014	40	64	—	(81) [(a)]	23
Year Ended December 31, 2013	32	66	—	(58) [(a)]	40
Income tax valuation allowance, deducted from deferred tax assets					
Year Ended December 31, 2015	$ 265	$ 3,039	$ 271	$ —	3,575
Year Ended December 31, 2014	291	—	(10)	(16)	265
Year Ended December 31, 2013	191	32	68	—	291

(a) Represents principally net amounts charged as uncollectible.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NRG ENERGY, INC.
(Registrant)

By: /s/ MAURICIO GUTIERREZ

Mauricio Gutierrez
Chief Executive Officer

Date: February 29, 2016

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints David R. Hill and Brian E. Curci, each or any of them, such person's true and lawful attorney-in-fact and agent with full power of substitution and resubstitution for such person and in such person's name, place and stead, in any and all capacities, to sign any and all amendments to this report on Form 10-K, and to file the same with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing necessary or desirable to be done in and about the premises, as fully to all intents and purposes as such person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or his or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

In accordance with the Exchange Act, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on February 29, 2016.

Signature	Title	Date
/s/ MAURICIO GUTIERREZ Mauricio Gutierrez	President, Chief Executive Officer and Director (Principal Executive Officer)	February 29, 2016
/s/ KIRKLAND B. ANDREWS Kirkland B. Andrews	Chief Financial Officer (Principal Financial Officer)	February 29, 2016
/s/ DAVID CALLEN David Callen	Chief Accounting Officer (Principal Accounting Officer)	February 29, 2016
/s/ HOWARD E. COSGROVE Howard E. Cosgrove	Chairman of the Board	February 29, 2016
/s/ EDWARD R. MULLER Edward R. Muller	Vice Chairman of the Board	February 29, 2016
E. Spencer Abraham	Director	February 29, 2016
/s/ KIRBYJON H. CALDWELL Kirbyjon H. Caldwell	Director	February 29, 2016
/s/ LAWRENCE S. COBEN Lawrence S. Coben	Director	February 29, 2016
/s/ TERRY G. DALLAS Terry G. Dallas	Director	February 29, 2016
/s/ WILLIAM E. HANTKE William E. Hantke	Director	February 29, 2016
/s/ PAUL W. HOBBY Paul W. Hobby	Director	February 29, 2016
/s/ ANNE C. SCHAUMBURG Anne C. Schaumburg	Director	February 29, 2016
/s/ EVAN J. SILVERSTEIN Evan J. Silverstein	Director	February 29, 2016
/s/ THOMAS H. WEIDEMEYER Thomas H. Weidemeyer	Director	February 29, 2016
/s/ WALTER R. YOUNG Walter R. Young	Director	February 29, 2016

EXHIBIT INDEX

Number	Description	Method of Filing
2.1	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.	Incorporated herein by reference to Exhibit 99.1 to the Registrant's current report on Form 8-K filed on November 19, 2003.
2.2	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.	Incorporated herein by reference to Exhibit 99.2 to the Registrant's current report on Form 8-K filed on November 19, 2003.
2.3	Acquisition Agreement, dated as of September 30, 2005, by and among NRG Energy, Inc., Texas Genco LLC and the Direct and Indirect Owners of Texas Genco LLC.	Incorporated herein by reference to Exhibit 2.1 to the Registrant's current report on Form 8-K filed on October 3, 2005.
2.4	Purchase and Sale Agreement by and between Denali Merger Sub Inc. and NRG Energy, Inc. dated as of August 13, 2010.	Incorporated herein by reference to Exhibit 99.2 to the Registrant's current report on Form 8-K filed on August 13, 2010.
2.5	Agreement and Plan of Merger, dated as of July 20, 2012, by and among NRG Energy, Inc., Plus Merger Corporation and GenOn Energy, Inc.	Incorporated herein by reference to Exhibit 2.1 to the Registrant's current report on Form 8-K filed on July 23, 2012.
2.6	Plan Sponsor Agreement, dated October 18, 2013, by and among NRG Energy, Inc., NRG Energy Holdings, Inc., Edison Mission Energy, certain of Edison Mission Energy's debtor subsidiaries, the Official Committee of Unsecured Creditors of Edison Mission Energy and its affiliated debtors, the PoJo Parties (as defined therein) and the proponent noteholders thereto.	Incorporated herein by reference to Exhibit 2.1 to Amendment No. 1 to the Registrant's current report on Form 8-K filed on October 21, 2013.
2.7	Asset Purchase Agreement, dated October 18, 2013, by and among NRG Energy, Inc., Edison Mission Energy and NRG Energy Holdings Inc.	Incorporated herein by reference to Exhibit 2.2 to Amendment No. 1 to the Registrant's current report on Form 8-K filed on October 21, 2013.
3.1	Amended and Restated Certificate of Incorporation.	Incorporated herein by reference to Exhibit 3.1 to the Registrant's quarterly report on Form 10-Q filed on May 3, 2012.
3.2	Certificate of Amendment to Amended and Restated Certificate of Incorporation.	Incorporated herein by reference to Exhibit 3.1 to the Registrant's current report on Form 8-K filed on December 14, 2012.
3.3	Second Amended and Restated By-Laws.	Incorporated herein by reference to Exhibit 3.2 to the Registrant's current report on Form 8-K filed on December 14, 2012.
3.4	Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 4, 2006.	Incorporated herein by reference to Exhibit 10.7 to the Registrant's current report on Form 8-K filed on August 10, 2006.
3.5	Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on February 27, 2008.	Incorporated herein by reference to Exhibit 3.1 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
3.6	Second Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 8, 2008.	Incorporated herein by reference to Exhibit 3.1 to the Registrant's quarterly report on Form 10-Q filed on October 30, 2008.
3.7	Certificate of Designations of 2.822% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on December 30, 2014.	Incorporated herein by reference to Exhibit 3.1 to the Registrant's current report on Form 8-K filed on December 30, 2014.
4.1	Supplemental Indenture, dated as of December 30, 2005, among NRG Energy, Inc., the subsidiary guarantors named on Schedule A thereto and Law Debenture Trust Company of New York, as trustee.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on January 4, 2006.
4.2	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto, dated as of January 6, 2004, together with Annex A to the Common Agreement.	Incorporated herein by reference to Exhibit 4.9 to the Registrant's annual report on Form 10-K filed on March 16, 2004.
4.3	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.	Incorporated herein by reference to Exhibit 4.10 to the Registrant's annual report on Form 10-K filed on March 16, 2004.

4.4	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.	Incorporated herein by reference to Exhibit 4.11 to the Registrant's annual report on Form 10-K filed on March 16, 2004.
4.5	Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.	Incorporated herein by reference to Exhibit 4.23 to the Registrant's annual report on Form 10-K filed on March 31, 2003.
4.6	Specimen of Certificate representing common stock of NRG Energy, Inc.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's quarterly report on Form 10-Q filed on August 4, 2006.
4.7	Indenture, dated February 2, 2006, among NRG Energy, Inc. and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on February 6, 2006.
4.8	Thirty-Sixth Supplemental Indenture, dated August 20, 2010, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on August 20, 2010.
4.9	Form of 8.25% Senior Note due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on August 20, 2010.
4.10	Registration Rights Agreement, dated August 20, 2010, among NRG Energy, Inc., the guarantors named therein and Citigroup Global Markets Inc., Banc of America Securities LLC and Deutsche Bank Securities Inc., as representatives of the several initial purchasers.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on August 20, 2010.
4.11	Forty-First Supplemental Indenture, dated as of December 15, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on December 16, 2010.
4.12	Forty-Second Supplemental Indenture, dated January 26, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on January 28, 2011.
4.13	Form of 7.625% Senior Note due 2018.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on January 28, 2011.
4.14	Registration Rights Agreement, dated January 26, 2011, among NRG Energy, Inc., the guarantors named therein and J.P. Morgan Securities LLC, as initial purchaser.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on January 28, 2011.
4.15	Forty-Eighth Supplemental Indenture, dated May 20, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.16	Forty-Ninth Supplemental Indenture, dated May 20, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.17	Fifty-First Supplemental Indenture, dated May 24, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.18	Form of 7.875% Senior Note due 2021.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on May 25, 2011.
4.19	Registration Rights Agreement, dated May 24, 2011, among NRG Energy, Inc., the guarantors named therein and Morgan Stanley & Co. Incorporated, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., J.P. Morgan Securities LLC and RBS Securities Inc., as representatives of the initial purchasers.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on May 25, 2011.

4.20	Fifty-Fourth Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.21	Fifty-Fifth Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.22	Fifty-Seventh Supplemental Indenture, dated November 8, 2011, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on November 8, 2011.
4.23	Sixtieth Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.24	Sixty-First Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.25	Sixty-Third Supplemental Indenture, dated April 5, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on April 6, 2012.
4.26	Sixty-Sixth Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.27	Sixty-Seventh Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.4 to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.28	Sixty-Ninth Supplemental Indenture, dated May 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on May 11, 2012.
4.29	Seventieth Supplemental Indenture, dated September 24, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on September 24, 2012.
4.30	Form of 6.625% Senior Note due 2023.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on September 24, 2012.
4.31	Seventy-Second Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.32	Seventy-Third Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.33	Seventy-Fifth Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on October 12, 2012.

4.34	Seventy-Sixth Supplemental Indenture, dated October 9, 2012, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on October 12, 2012.
4.35	Senior Indenture, dated December 22, 2004, between Reliant Energy, Inc. and Wilmington Trust Company.	Incorporated herein by reference to Exhibit 4.1 to GenOn Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.
4.36	Fourth Supplemental Indenture, dated June 13, 2007, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company as Trustee, re: GenOn Energy, Inc.'s 7.625% Senior Notes due 2014.	Incorporated herein by reference to Exhibit 4.1 to GenOn Energy Inc.'s current report on Form 8-K filed on June 15, 2007.
4.37	Fifth Supplemental Indenture, dated June 13, 2007, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company as Trustee, re: GenOn Energy, Inc.'s 7.875% Senior Notes due 2017.	Incorporated herein by reference to Exhibit 4.2 to GenOn Energy Inc.'s current report on Form 8-K filed June 15, 2007.
4.38	Indenture, dated May 1, 2001, between Mirant Americas Generation, Inc. and Bankers Trust Company as Trustee.	Incorporated herein by reference to Exhibit 4.1 to Mirant Americas Generation, Inc.'s Registration Statement on Form S-4 filed on June 18, 2001.
4.39	Third Supplemental Indenture, dated May 1, 2001, between Mirant Americas Generation, Inc. and Bankers Trust Company as Trustee, re: GenOn Americas Generation, LLC's 9.125% Senior Notes due 2031.	Incorporated herein by reference to Exhibit 4.4 to Mirant Americas Generation, Inc.'s Registration Statement on Form S-4 filed on June 18, 2001.
4.40	Fifth Supplemental Indenture, dated October 9, 2001, between Mirant Americas Generation, Inc. and Bankers Trust Company as Trustee, re: GenOn Americas Generation, LLC's 8.5% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.6 to Mirant Americas Generation, Inc.'s Registration Statement on Form S-4/A filed on May 7, 2002.
4.41	Sixth Supplemental Indenture, dated November 1, 2001, between Mirant Americas Generation LLC and Bankers Trust Company, re: Indenture, dated May 1, 2001.	Incorporated herein by reference to Exhibit 4.6 to Mirant Corporation's annual report on Form 10-K filed on February 27, 2009.
4.42	Seventh Supplemental Indenture, dated January 3, 2006, between Mirant Americas Generation LLC and Wells Fargo Bank National Association (as successor to Bankers Trust Company), re: Indenture, dated May 1, 2001.	Incorporated herein by reference to Exhibit 4.1 to Mirant Americas Generation, LLC's quarterly report on Form 10-Q filed on May 14, 2007.
4.43	Senior Notes Indenture, dated October 4, 2010, by GenOn Escrow Corp. and Wilmington Trust Company as trustee, re: GenOn Energy, Inc.'s 9.5% Senior Notes due 2018 and 9.875% Senior Notes due 2020.	Incorporated by reference to Exhibit 4.4 to Mirant Corporation's quarterly report on Form 10-Q filed on November 5, 2010.
4.44	Supplemental Indenture, dated December 3, 2010, by and among GenOn Energy, Inc., GenOn Escrow Corp. and Wilmington Trust Company as trustee, re: GenOn Energy, Inc.'s 9.5% Senior Notes due 2018 and 9.875% Senior Notes due 2020.	Incorporated by reference to Exhibit 4.2 to GenOn Energy Inc.'s current report on Form 8-K filed on December 7, 2010.
4.45	Seventy-Eighth Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.46	Seventy-Ninth Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.47	Eighty-First Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.48	Eighty-Second Supplemental Indenture, dated as of January 3, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on January 9, 2013.
4.49	Eighty-Fourth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.50	Eighty-Fifth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.51	Eighty-Seventh Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on March 13, 2013.

4.52	Eighty-Eighth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.53	Eighty-Ninth Supplemental Indenture, dated as of March 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.7 to the Registrant's current report on Form 8-K filed on March 13, 2013.
4.54	Ninety-First Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.55	Ninety-Second Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.56	Ninety-Fourth Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.57	Ninety-Fifth Supplemental Indenture, dated as of May 2, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on May 3, 2013.
4.58	Ninety-Seventh Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.59	Ninety-Eighth Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.60	One Hundredth Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.61	One Hundred-First Supplemental Indenture, dated as of September 4, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on September 6, 2013.
4.62	One Hundred-Third Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.63	One Hundred-Fourth Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.625% Senior Notes due 2018.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.64	One Hundred-Sixth Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 7.875% Senior Notes due 2021.	Incorporated herein by reference to Exhibit 4.5 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.65	One Hundred-Seventh Supplemental Indenture, dated as of October 7, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.6 to the Registrant's current report on Form 8-K filed on October 8, 2013.
4.66	One Hundred-Eighth Supplemental Indenture, dated as of November 13, 2013, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019, 8.25% Senior Notes due 2020, 7.625% Senior Notes due 2018, 7.625% Senior Notes due 2019, 7.875% Senior Notes due 2021 and 6.625% Senior Notes due 2023.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on November 13, 2013.
4.67	One Hundred-Ninth Supplemental Indenture, dated as of January 27, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy's 6.25% Senior Notes due 2022.	Incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on January 27, 2014.

4.68	Form of 6.25% Senior Note due 2022.	Incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on January 27, 2014.
4.69	Registration Rights Agreement, dated January 27, 2014, among NRG Energy, Inc., the guarantors named therein and Barclays Capital Inc., Deutsche Bank Securities Inc., Goldman, Sachs & Co., Morgan Stanley & Co. LLC, Credit Agricole Securities (USA) Inc., Natixis Securities Americas LLC and RBC Capital Markets, LLC, as initial purchasers.	Incorporated herein by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on January 27, 2014.
4.70	One Hundred-Tenth Supplemental Indenture, dated as of March 24, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019, 8.25% Senior Notes due 2020, 7.625% Senior Notes due 2018, 7.625% Senior Notes due 2019, 7.875% Senior Notes due 2021, 6.625% Senior Notes due 2023 and 6.25% Senior Notes due 2022.	Incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on March 28, 2014.
4.71	Indenture, dated as of April 21, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 6.25% Senior Notes due 2024.	Incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on April 21, 2014.
4.72	Form of 6.25% Senior Note due 2024.	Incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on April 21, 2014.
4.73	Registration Rights Agreement, dated April 21, 2014, among NRG Energy, Inc., the guarantors named therein and Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA), Inc., J.P. Morgan Securities LLC, Mitsubishi UFJ Securities (USA), Inc., SMBC Nikko Securities America, Inc. and RBS Securities Inc.	Incorporated herein by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on April 21, 2014.
4.74	One Hundred-Eleventh Supplemental Indenture, dated as of April 28, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.5% Senior Notes due 2019, 8.25% Senior Notes due 2020, 7.625% Senior Notes due 2018, 7.625% Senior Notes due 2019, 7.875% Senior Notes due 2021, 6.625% Senior Notes due 2023 and 6.25% Senior Notes due 2022.	Incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 2, 2014.
4.75	First Supplemental Indenture, dated as of May 2, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.25% Senior Notes due 2024.	Incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 2, 2014.
4.76	One Hundred-Twelfth Supplemental Indenture, dated as of October 3, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on October 3, 2014.
4.77	Second Supplemental Indenture, dated as of October 3, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 6.25% Senior Notes due 2024.	Incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on October 3, 2014.
4.78	One Hundred-Thirteenth Supplemental Indenture, dated as of November 12, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020, 7.625% Senior Notes due 2018, 7.875% Senior Notes due 2021, 6.625% Senior Notes due 2023 and 6.25% Senior Notes due 2022.	Incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on November 14, 2014.
4.79	Third Supplemental Indenture, dated as of November 12, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on November 14, 2014.
4.80	One Hundred-Fourteenth Supplemental Indenture, dated as of November 24, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York, as trustee, re: NRG Energy, Inc.'s 8.25% Senior Notes due 2020, 7.625% Senior Notes due 2018, 7.875% Senior Notes due 2021, 6.625% Senior Notes due 2023 and 6.25% Senior Notes due 2022.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's current report on Form 8-K filed on November 25, 2014.
4.81	Fourth Supplemental Indenture, dated as of November 24, 2014, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York, as trustee, re: NRG Energy, Inc.'s 6.25% Senior Notes due 2024.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's current report on Form 8-K filed on November 25, 2014.
4.82	One Hundred-Fifteenth Supplemental Indenture, dated as of April 8, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.1 to the Company's current report on Form 8-K filed on April 9, 2015.

4.83	Fifth Supplemental Indenture, dated as of April 8, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.2 to the Company's current report on Form 8-K filed on April 9, 2015.
4.84	One Hundred-Sixteenth Supplemental Indenture, dated as of April 29, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.1 to the Company's current report on Form 8-K filed on April 30, 2015.
4.85	Sixth Supplemental Indenture, dated as of April 29, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.2 to the Company's current report on Form 8-K filed on April 30, 2015.
4.86	One Hundred-Seventeenth Supplemental Indenture, dated as of May 22, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.1 to the Company's current report on Form 8-K filed on May 22, 2015.
4.87	Seventh Supplemental Indenture, dated as of May 22, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.2 to the Company's current report on Form 8-K filed on May 22, 2015.
4.88	One Hundred-Eighteenth Supplemental Indenture, dated as of October 28, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.1 to the Company's current report on Form 8-K filed on November 2, 2015.
4.89	Eighth Supplemental Indenture, dated as of October 28, 2015, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York.	Incorporated herein by reference to Exhibit 4.2 to the Company's current report on Form 8-K filed on November 2, 2015.
10.1	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.	Incorporated herein by reference to Exhibit 10.5 to the Registrant's Registration Statement on Form S-1, as amended, Registration No. 333-33397.
10.2	Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.	Incorporated herein by reference to Exhibit 10.4 to the Registrant's Registration Statement on Form S-1, as amended, Registration No. 333-33397.
10.3*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.	Incorporated herein by reference to Exhibit 10.14 to the Registrant's annual report on Form 10-K filed on March 30, 2005.
10.4*	Form of NRG Energy, Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.	Incorporated herein by reference to Exhibit 10.15 to the Registrant's annual report on Form 10-K filed on March 30, 2005.
10.5*	Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's quarterly report on Form 10-Q filed on November 9, 2004.
10.6*	Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.	Incorporated herein by reference to Exhibit 10.2 to the Registrant's quarterly report on Form 10-Q filed on November 9, 2004.
10.7*	Form of NRG Energy, Inc. Long Term Incentive Plan Performance Stock Unit Agreement.	Incorporated herein by reference to Exhibit 10.7 to the Registrant's annual report on Form 10-K filed on February 23, 2010.
10.8*	Second Amended and Restated Annual Incentive Plan for Designated Corporate Officers.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on May 7, 2015.
10.9	Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.	Incorporated herein by reference to Exhibit 10.28 to the Registrant's annual report on Form 10-K filed on March 30, 2005.
10.10	Purchase Agreement (West Coast Power) dated as of December 27, 2005, by and among NRG Energy, Inc., NRG West Coast LLC (Buyer), DPC II Inc. (Seller) and Dynegy, Inc.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on December 28, 2005.
10.11	Purchase Agreement (Rocky Road Power), dated as of December 27, 2005, by and among Termo Santander Holding, L.L.C.(Buyer), Dynegy, Inc., NRG Rocky Road LLC (Seller) and NRG Energy, Inc.	Incorporated herein by reference to Exhibit 10.2 to the Registrant's current report on Form 8-K filed on December 28, 2005.
10.12	Stock Purchase Agreement, dated as of August 10, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on August 11, 2005.
10.13	Agreement with respect to the Stock Purchase Agreement, dated December 19, 2008, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.	Incorporated herein by reference to Exhibit 10.13 to the Registrant's annual report on Form 10-K filed on February 12, 2009.

10.14	Investor Rights Agreement, dated as of February 2, 2006, by and among NRG Energy, Inc. and Certain Stockholders of NRG Energy, Inc. set forth therein.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on February 8, 2006.
10.15†	Terms and Conditions of Sale, dated as of October 5, 2005, between Texas Genco II LP and Freight Car America, Inc., (including the Proposal Letter and Amendment thereto).	Incorporated herein by reference to Exhibit 10.32 to the Registrant's annual report on Form 10-K filed on March 7, 2006.
10.16*	Amended and Restated Employment Agreement, dated December 4, 2008, between NRG Energy, Inc. and David Crane.	Incorporated herein by reference to Exhibit 10.16 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.17*	Amendment 2014-1 to the Amended and Restated Employment Agreement between NRG Energy, Inc. and David Crane, dated December 4, 2014.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on December 10, 2014.
10.18*	General Release, dated January 4, 2016, between NRG Energy, Inc. and David Crane.	Incorporated herein by reference to Exhibit 10.2 to the Registrant's current report on Form 8-K/A filed on January 8, 2016.
10.19	Limited Liability Company Agreement of NRG Common Stock Finance I LLC.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on August 10, 2006.
10.20	Note Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse International and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.3 to the Registrant's current report on Form 8-K filed on August 10, 2006.
10.21	Amendment Agreement, dated February 27, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.5 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.22	Amendment Agreement, dated December 19, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.23 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.23	Amendment Agreement, dated December 19, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance II LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.26 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.24	Agreement with respect to Note Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, NRG Energy, Inc., Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.24 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.25	Agreement with respect to Note Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance II LLC, NRG Energy, Inc., Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.27 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.26	Preferred Interest Purchase Agreement, dated August 4, 2006, between NRG Common Stock Finance I LLC, Credit Suisse Capital LLC and Credit Suisse Securities (USA) LLC, as agent.	Incorporated herein by reference to Exhibit 10.5 to the Registrant's current report on Form 8-K filed on August 10, 2006.
10.27	Preferred Interest Amendment Agreement, dated February 27, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse Capital LLC, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.6 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.28	Preferred Interest Amendment Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.31 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.29	Preferred Interest Amendment Agreement, dated December 19, 2008, by and among NRG Common Stock Finance II LLC, Credit Suisse Capital LLC, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.34 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.30	Agreement with respect to Preferred Interest Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance I LLC, NRG Energy, Inc., Credit Suisse Capital LLC, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.32 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.31	Agreement with respect to Preferred Interest Purchase Agreement, dated December 19, 2008, by and among NRG Common Stock Finance II LLC, NRG Energy, Inc., Credit Suisse Capital LLC, and Credit Suisse Securities (USA) LLC.	Incorporated herein by reference to Exhibit 10.35 to the Registrant's annual report on Form 10-K filed on February 12, 2009.
10.32*	NRG Energy, Inc. Executive Change-in-Control and General Severance Agreement, dated December 9, 2008.	Incorporated herein by reference to Exhibit 10.40 to the Registrant's annual report on Form 10-K filed on February 12, 2009.

10.33†	Amended and Restated Contribution Agreement (NRG), dated March 25, 2008, by and among Texas Genco Holdings, Inc., NRG South Texas LP and NRG Nuclear Development Company LLC and Certain Subsidiaries Thereof.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.34†	Contribution Agreement (Toshiba), dated February 29, 2008, by and between Toshiba Corporation and NRG Nuclear Development Company LLC.	Incorporated herein by reference to Exhibit 10.2 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.35†	Multi-Unit Agreement, dated February 29, 2008, by and among Toshiba Corporation, NRG Nuclear Development Company LLC and NRG Energy, Inc.	Incorporated herein by reference to Exhibit 10.3 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.36†	Amended and Restated Operating Agreement of Nuclear Innovation North America LLC, dated May 1, 2008.	Incorporated herein by reference to Exhibit 10.4 to the Registrant's quarterly report on Form 10-Q filed on May 1, 2008.
10.37†	LLC Membership Interest Purchase Agreement between Reliant Energy, Inc. and NRG Retail LLC, dated as of February 28, 2009.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's quarterly report on Form 10-Q filed on April 30, 2009.
10.38	Project Agreement, Settlement Agreement and Mutual Release, dated March 1, 2010, by and among by and among Nuclear Innovation North America LLC, the City of San Antonio acting by and through the City Public Service Board of San Antonio, a Texas municipal utility, NINA Texas 3 LLC and NINA Texas 4 LLC, and solely for purposes of certain sections of the Settlement Agreement, by NRG Energy, Inc and NRG South Texas LP.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on March 2, 2010.
10.39†	STP 3 & 4 Owners Agreement, dated March 1, 2010, by and among Nuclear Innovation North America LLC, the City of San Antonio, NINA Texas 3 LLC and NINA Texas 4 LLC.	Incorporated herein by reference to Exhibit 10.2 to the Registrant's current report on Form 8-K filed on March 2, 2010.
10.40*	2009 Executive Change-in-Control and General Severance Plan.	Incorporated herein by reference to Exhibit 10.2 to the Registrant's current report on Form 8-K filed on April 1, 2010.
10.41†	Investment and Option Agreement by and among NINA Investments Holdings LLC, Nuclear Innovation North America LLC and TEPCO Nuclear Energy America LLC, dated as of May 10, 2010.	Incorporated herein by reference to Exhibit 10.3 to the Registrant's quarterly report on Form 10-Q filed on August 2, 2010.
10.42†	Parent Company Agreement by and among NRG Energy, Inc., Nuclear Innovation North America LLC, The Tokyo Electric Power Company and TEPCO Nuclear Energy America LLC, dated as of May 10, 2010.	Incorporated herein by reference to Exhibit 10.4 to the Registrant's quarterly report on Form 10-Q filed on August 2, 2010.
10.43(a)	Letter of Credit and Reimbursement Agreement, dated as of June 30, 2010, by and among NRG LC Facility Company LLC, NRG Energy, Inc. and Citibank, N.A.	Incorporated herein by reference to Exhibit 10.2(a) the Registrant's current report on Form 8-K filed on July 1, 2010.
10.43(b)	Letter of Credit and Reimbursement Agreement, dated as of June 30, 2010, by and among NRG LC Facility Company LLC, NRG Energy, Inc. and Deutsche Bank AG, New York Bank.	Incorporated herein by reference to Exhibit 10.2(b) to the Registrant's current report on Form 8-K filed on July 1, 2010.
10.44*	The NRG Energy, Inc. Amended and Restated Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on August 3, 2010.
10.45	Amended and Restated Credit Agreement, dated July 1, 2011, by and among NRG Energy, Inc., the lenders party thereto, the joint lead bookrunners and joint lead arrangers party thereto, Citicorp North America, Inc., Morgan Stanley Senior Funding, Inc. and the documentation agents party thereto.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on July 5, 2011.
10.46*	Form of Market Stock Unit Grant Agreement.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K/A filed on September 12, 2011.
10.47	Registration Rights Agreement, dated September 24, 2012, among NRG Energy, Inc., the guarantors named therein and Deutsche Bank Securities Inc., Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Goldman, Sachs & Co., J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and RBS Securities Inc., as initial purchasers.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on September 24, 2012.
10.48*	NRG 2010 Stock Plan for GenOn Employees.	Incorporated herein by reference to Exhibit 10.49 to the Registrant’s annual report on Form 10-K filed on February 27, 2013.
10.49	Revolving Credit Agreement among GenOn Energy, Inc., as Borrower, GenOn Americas, Inc., as Borrower, the several lenders from time to time parties thereto, and NRG Energy, Inc., as Administrative Agent, dated as of December 14, 2012.	Incorporated herein by reference to Exhibit 10.50 to the Registrant’s annual report on Form 10-K filed on February 27, 2013.

10.50	First Amendment Agreement, dated as of February 6, 2013, to the Amended and Restated Credit Agreement and the Second Amended and Restated Collateral Trust Agreement.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's quarterly report on Form 10-Q filed on May 7, 2013.
10.51	Second Amendment Agreement, dated as of June 4, 2013, to the Amended and Restated Credit Agreement, the Second Amended and Restated Collateral Trust Agreement and the Amended and Restated Guarantee and Collateral Agreement.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on June 10, 2013.
10.52*	NRG Energy, Inc. Long-Term Incentive Plan Market Stock Unit Agreement.	Incorporated herein by reference to Exhibit 10.53 to the Registrant's annual report on Form 10-K filed on February 28, 2014.
10.53*	NRG Energy, Inc. 2010 Stock Plan For GenOn Employees Market Stock Unit Agreement	Incorporated herein by reference to Exhibit 10.54 to the Registrant's annual report on Form 10-K filed on February 28, 2014.
10.54*	Amended and Restated Employee Stock Purchase Plan.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's quarterly report on Form 10-Q filed on August 7, 2014.
10.55	Amendment Agreement, dated as of December 23, 2014, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on December 30, 2014.
10.56	Employment Agreement, dated December 21, 2015, by and between NRG Energy, Inc. and Mauricio Gutierrez	Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on December 24, 2015.
12.1	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges.	Filed herewith.
12.2	NRG Energy, Inc. Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividend Requirements.	Filed herewith.
21.1	Subsidiaries of NRG Energy, Inc.	Filed herewith.
23.1	Consent of KPMG LLP.	Filed herewith.
31.1	Rule 13a-14(a)/15d-14(a) certification of Mauricio Gutierrez	Filed herewith.
31.2	Rule 13a-14(a)/15d-14(a) certification of Kirkland B. Andrews.	Filed herewith.
31.3	Rule 13a-14(a)/15d-14(a) certification of David Callen.	Filed herewith.
32	Section 1350 Certification.	Filed herewith.
101 INS	XBRL Instance Document.	Filed herewith.
101 SCH	XBRL Taxonomy Extension Schema.	Filed herewith.
101 CAL	XBRL Taxonomy Extension Calculation Linkbase.	Filed herewith.
101 DEF	XBRL Taxonomy Extension Definition Linkbase.	Filed herewith.
101 LAB	XBRL Taxonomy Extension Label Linkbase.	Filed herewith.
101 PRE	XBRL Taxonomy Extension Presentation Linkbase.	Filed herewith.

* Exhibit relates to compensation arrangements.

† Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Secretary of the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

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