NRG ENERGY, INC.
Form 10-K
February 29, 2016

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

x	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the Fiscal Year ended December 31, 2015.
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the Transition period from to .

Commission file No. 001-15891

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

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

(609) 524-4500
(Registrant's telephone number, including area code)

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

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

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

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

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

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

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

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

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

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

(Do not check if a smaller reporting company)

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

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $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

TABLE OF CONTENTS

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

8

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.

16

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 Amor-tization	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	

53

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

54

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 [(1)]	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	Megawat Thermal Equivale Capacity (MWt)	Ge Ca
NRG Energy Center Minneapolis, MN	100.0		Approx. 100 steam and 50 chilled water customers	322 136	St 1,1 M Ch wa 38
NRG Energy Center San Francisco, CA	100.0		Approx 175 steam customers	133	St M
NRG Energy Center Omaha, NE	100.0 12.0[a] 0%[a]	100.0	Approx 60 steam and 60 chilled water customers	142 73 77 26	St M St M Ch wa 22 Ch wa 7,2
NRG Energy Center Harrisburg, PA	100.0		Approx 140 steam and 3 chilled water	108 13	St M Ch wa

		customers		3,6 Ste MI Ch wa
NRG Energy Center Phoenix, AZ	0%[a] 100.0 12.0[a] 0%[a]	Approx 35 chilled water customers	4 104 14 28	29 Ch wa 3,9 Ch wa 8,0
NRG Energy Center Pittsburgh, PA	100.0	Approx 25 steam and 25 chilled water customers	88 46	Ste MI Ch wa 12
NRG Energy Center San Diego, CA	100.0	Approx 15 chilled water customers	31	Ch wa 7,4
NRG Energy Center Dover, DE	100.0	Kraft Foods Inc. and Procter & Gamble Company	66	Ste MI
NRG Energy Center Princeton, NJ	100.0	Princeton HealthCare System	21 17	Ste MI Ch wa 4,7
		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.

56

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 — Security 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:

	Year Ended December 31,		
(In millions except otherwise noted)	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	Elim-inations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Elim-inations/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	Elim-inations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Elim-inations/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.

68

	Years ended December 31,		
Weather Metrics	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

	Years ended December 31,	
(In millions except otherwise noted)	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

72

Operations and maintenance expense

	NRG Business				NRG	NRG				
	Gulf Coast	East	West	B2B	NRG Home Retail	NRG Home Solar	NRG Renew	NRG Yield	Eliminations	Total
	(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:

	Year Ended December 31,			
(In millions except otherwise noted)	2014[a]	2013	Change %	
Operating Revenues				
Energy revenue [b]	$5,422	$3,530	54	%
Capacity revenue [b]	2,087	1,800	16	
Retail revenue	7,376	6,287	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

77

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	Elim-inations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Elim-inations/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	Elim-inations	Subtotal	Retail	Solar	NRG Renew	NRG Yield	Elim-inations/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

79

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									