NRG ENERGY, INC.
Form 10-K
February 28, 2019

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, 2018.

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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 every Interactive Data File required to be submitted 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 such files). Yes x No o

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $7,964,294,696 based on the closing sale price of $30.70 as reported on the New York Stock Exchange.

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

Class	Outstanding at January 31, 2019
Common Stock, par value $0.01 per share	280,997,550

Documents Incorporated by Reference:

Portions of the Registrant's definitive Proxy Statement relating to its 2019 Annual Meeting of Stockholders are incorporated by reference into Part III of this Annual Report on Form 10-K

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Glossary of Terms

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

2023 Term Loan Facility	The Company's $1.7 billion term loan facility due 2023, a component of the Senior Credit Facility
Adjusted EBITDA	Adjusted earnings before interest, taxes, depreciation and amortization
ARO	Asset Retirement Obligation
ASC	The FASB Accounting Standards Codification, which the FASB established as the source of authoritative 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
Bankruptcy Code	Chapter 11 of Title 11 of the U.S. Bankruptcy Code
Bankruptcy Court	United States Bankruptcy Court for the Southern District of Texas, Houston Division
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
Business Solutions	NRG's business solutions group, which includes demand response, commodity sales, energy efficiency and energy management services
CAA	Clean Air Act
CAISO	California Independent System Operator
Carlsbad	Carlsbad Energy Center, a 528 MW natural gas-fired project located in Carlsbad, CA
CCF	Carbon Capture Facility
CDD	Cooling Degree Day
CDWR	California Department of Water Resources
CFTC	U.S. Commodity Futures Trading Commission
Chapter 11 Cases	Voluntary cases commenced by the GenOn Entities under the Bankruptcy Code in the Bankruptcy Court
C&I	Commercial, industrial and governmental/institutional
CES	Clean Energy Standard
Cleco	Cleco Corporate Holdings LLC
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalents
ComEd	Commonwealth Edison
Company	NRG Energy, Inc.
CPP	Clean Power Plan
CPUC	California Public Utilities Commission
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
Distributed Solar	Solar power projects that primarily sell power to customers for usage on site, or are interconnected to sell power into a local distribution grid
DNREC	Delaware Department of Natural Resources and Environmental Control
Dominion	Dominion Resources, Inc.
DSI	Dry Sorbent Injection
DSU	Deferred Stock Unit
Economic gross margin	Sum of energy revenue, capacity revenue, retail revenue and other revenue, less cost of fuels and other cost of sales
EGU	Electric Generating Unit
Emani	European Mutual Association for Nuclear Insurance

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EME	Edison Mission Energy
EMAAC	Eastern Mid-Atlantic Area Council
Energy Plus Holdings	Energy Plus Holdings LLC
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPSA	The Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESP	Electrostatic Precipitator
ESPP	NRG Energy, Inc. Amended and Restated Employee Stock Purchase Plan
ESPS	Existing Source Performance Standards
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FPA	Federal Power Act
Fresh Start	Reporting requirements as defined by ASC-852, Reorganizations
FTRs	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the U.S.
GenConn	GenConn Energy LLC
GenOn	GenOn Energy, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC
GenOn Entities	GenOn and certain of its wholly owned subsidiaries, including GenOn Americas Generation, that filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court on June 14, 2017
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
GHG	Greenhouse Gas
GIP	Global Infrastructure Partners
Green Mountain Energy	Green Mountain Energy Company
GW	Gigawatt
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 kWhs 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
HLBV	Hypothetical Liquidation at Book Value
HLW	High-level radioactive waste
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
Indexed Rate	An indexed rate means that the price of the electricity sold to the customer is tied to an underlying variable, or index, such as monthly closing of NYMEX natural gas
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
kWh	Kilowatt-hour

LaGen	Louisiana Generating LLC
LIBOR	London Inter-Bank Offered Rate
LSE	Load Serving Entities
LTIPs	Collectively, the NRG LTIP and the NRG GenOn LTIP
LTSA	Long-Term Service Agreement
Mass Market	Residential and small commercial customers
MATS	Mercury and Air Toxics Standards promulgated by the EPA
MDth	Thousand Dekatherms
Merger	The merger completed on December 14, 2012 by NRG and GenOn pursuant to the Merger Agreement
Midwest Generation	Midwest Generation, LLC
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MSU	Market Stock Unit
MW	Megawatts
MWh	Saleable megawatt hour net of internal/parasitic load megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEIL	Nuclear Electric Insurance Limited
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
NJBPU	New Jersey Board of Public Utilities
NOL	Net Operating Loss
NO_x	Nitrogen Oxides
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 Energy, Inc. Amended and Restated Long-Term Incentive Plan
NRG Yield, Inc.	NRG Yield, Inc., which changed it's name to Clearway energy, Inc. following the sale by NRG or NRG Yield and the Renewables Platform to GIP
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
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSPSC	New York State Public Service Commission
OCI/OCL	Other Comprehensive Income/(Loss)
ORDC	Operating Reserve Demand Curve

PA PUC	Pennsylvania Public Utility Commission

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Peaking	Units expected to satisfy demand requirements during the periods of greatest or peak load on the system
PER	Peak Energy Rent
Petition Date	June 14, 2017
PG&E	PG&E Corporation (NYSE: PCG) and its primary operating subsidiary, Pacific Gas and Electric Company
Pipeline	Projects that range from identified lead to shortlisted with an offtake, and represents a lower level of execution certainty
PJM	PJM Interconnection, LLC
PM2.5	Particulate Matter that has a diameter of less than 2.5 micrometers
PPA	Power Purchase Agreement
PPM	Parts per million
PSU	Performance Stock Unit
PTC	Production Tax Credit
PUCT	Public Utility Commission of Texas
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act of 1976
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
Renewables	Consist of the following projects retained by NRG: Agua, Ivanpah, Guam, NFL stadiums
Renewables Platform	The renewable operating and development platform sold to GIP with NRG's interest in NRG Yield.
Restructuring Support Agreement	Restructuring Support and Lock-Up Agreement, dated as of June 12, 2017 and as amended on October 2, 2017, by and among GenOn Energy, Inc., GenOn Americas Generation, LLC, and subsidiaries signatory thereto, NRG Energy, Inc. and the noteholders signatory thereto
Retail	Reporting segment that includes NRG's residential and small commercial businesses which go to market as Reliant, NRG and other brands owned by NRG, as well as Business Solutions
Revolving Credit Facility	The Company's $2.4 billion revolving credit facility, a component of the Senior Credit Facility, due 2021
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROFO	Right of First Offer
ROFO Agreement	Second 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
RPSU	Relative Performance Stock Unit
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SCE	Southern California Edison Company
SCR	Selective Catalytic Reduction Control System
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
Senior Credit Facility	NRG's senior secured credit facility, comprised of the Revolving Credit Facility and the 2023 Term Loan Facility Prior to June 30, 2016, the Company's senior secured facility, comprised of the Term Loan Facility and the Revolving Credit Facility. On June 30, 2016, the Company replaced the Senior

Credit Facility with the 2016 Senior Credit Facility

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Senior Notes	As of December 31, 2018, NRG's $3.8 billion outstanding unsecured senior notes consisting of $733 million of 6.25% senior notes due 2024, $1.0 billion of the 7.25% senior notes due 2026, $1.23 billion of the 6.625% senior notes due 2027, and $821 million of 5.75% senior notes due 2028
Services Agreement	NRG provided GenOn with various management, personnel and other services, which include human resources, regulatory and public affairs, accounting, tax, legal, information systems, treasury, risk management, commercial operations, and asset management, as set forth in the services agreement with GenOn
Settlement Agreement	A settlement agreement and any other documents necessary to effectuate the settlement among NRG, GenOn, and certain holders of senior unsecured notes of GenOn Americas Generations and GenOn, and certain of GenOn's direct and indirect subsidiaries
SNF	Spent Nuclear Fuel
SO_2	Sulfur Dioxide
South Central Portfolio	NRG's South Central Portfolio, which owns and operates a 3,555 MW portfolio of generation assets consisting of 225 MW Bayou Cove, 430 MW Big Cajun-I, 1,461 MW Big Cajun-II, 1,263 MW Cottonwood and 176 MW Sterlington, and serves a customer base of cooperatives, municipalities and regional utilities under load contracts.
SPP	Solar Power Partners
S&P	Standard & Poor's
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
Tax Act	The Tax Cuts and Jobs Act of 2017
Term Loan Facility	Prior to June 30, 2016, the Company's $2.0 billion term loan facility due 2018.
Texas Genco	Texas Genco LLC
TSA	Transportation Services Agreement
TSR	Total Shareholder Return
TWCC	Texas Westmoreland Coal Co.
TWh	Terawatt Hour
UPMC	University of Pittsburgh Medical Center
U.S.	United States of America
U.S. DOE	U.S. Department of Energy
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
VCP	Voluntary Clean-Up Program
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council
ZECs	Zero Emissions Credits

PART I

Item 1 — Business

General

NRG Energy, Inc., or NRG or the Company, is an energy company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to consumers by producing, selling and delivering electricity and related products and services in major competitive power markets in the U.S. in a manner that delivers value to all of NRG's stakeholders. NRG is perfecting the integrated model by balancing retail load with generation supply within its deregulated markets, while evolving to a customer-driven business. The Company sells energy, services, and innovative, sustainable products and services directly to retail customers under the names "NRG" and "Reliant" and other brand names owned by NRG supported by approximately 23,000[(a)] MW of generation as of December 31, 2018. NRG was incorporated as a Delaware corporation on May 29, 1992.

Strategy

NRG's strategy is to maximize stockholder value through the safe production and sale of reliable power to its customers in the markets served by the Company, while positioning the Company to provide innovative solutions to the end-use energy consumer. This strategy is designed to enable the Company to optimize the integrated model to generate predictable cash flow, significantly strengthen earnings and cost competitiveness, and lower risk and volatility. Sustainability is an integral piece of NRG's strategy and ties directly to business success, reduced risks and brand value.

To effectuate the Company’s strategy, NRG is focused on: (i) 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; (ii) deploying innovative and renewable energy solutions for consumers within its retail businesses; (iii) excellence in operating performance of its existing assets including optimal hedging of generation assets and retail load operations; and (iv) engaging in a proactive capital allocation plan within the dictates of prudent balance sheet management.

Transformation Plan

NRG is well underway in executing its Transformation Plan. The Company expects to fully implement the Transformation Plan by the end of 2020 with a significant portion completed in 2018. The three-part, three-year plan is comprised of the following targets and the Company's achievements towards such targets are as follows:

Operations and Cost Excellence

Recurring cost savings and margin enhancement of $1,065 million, which consists of $590 million of cumulative cost savings, a $215 million net margin enhancement program, $50 million annual reduction in maintenance capital expenditures, and $210 million in permanent selling, general and administrative expense reduction associated with asset sales. The Company realized annual cost savings of $532 million and $32 million of margin enhancements during the year ended December 31, 2018 and is on track to realize $590 million of cost savings and $135 million of margin enhancements in 2019.

The Company expects to realize (i) $370 million of non-recurring working capital improvements through 2020 and (ii) approximately $290 million of one-time costs to achieve. By December 31, 2018, NRG has realized $333 million of non-recurring working capital improvements and $194 million of one-time costs to achieve, and expects to incur approximately $95 million of one-time costs to achieve in 2019.

Portfolio Optimization

Targeted and completed $3.0 billion of asset sale cash proceeds received through February 28, 2019.

Capital Structure and Allocation

As of December 31, 2018, the Company achieved the previously announced target of reducing consolidated corporate debt to 3.0x net debt / adjusted EBITDA[(b)] credit ratio on a pro forma basis that includes the South Central Portfolio sale proceeds. As of February 28, 2019, the Company completed $1.5 billion of share repurchases.

(a) excluding discontinued operations and held for sale
(b) adjusted EBITDA as defined per the Senior Credit Facility

Business Overview

As of December 31, 2018, the Company’s core businesses include (i) retail electricity and natural gas for residential, industrial and commercial consumers, including personal power solutions and Business Solutions, which includes C&I customers and other distributed and reliability products, and (ii) wholesale conventional generation primarily to support the retail business. The Company is committed to continuing to evaluate and streamline its generation portfolio to focus on locational value and supporting the retail business in each of the markets where the Company participates. In furtherance of this goal, during 2018, NRG divested non-core businesses which included, among others: (i) NRG Yield, Inc. and the Company's Renewables Platform, and (ii) the Company's South Central Portfolio. The Company previously had an ownership interest in GenOn Energy, Inc. which filed for bankruptcy on June 14, 2017. As a result of the bankruptcy filing, NRG determined it no longer controlled GenOn and deconsolidated GenOn and its subsidiaries for financial reporting purposes. On December 14, 2018, GenOn emerged from bankruptcy as a standalone company no longer owned by NRG.

Retail

Retail provides energy and related services to residential, industrial and commercial consumers through various brands and sales channels across the U.S. In 2018, Retail delivered approximately 67 TWhs of electricity and 11 MDth of natural gas and served approximately 3.1 million customers. Retail's results make it one of the largest competitive energy retailers in the U.S. As of the end of 2018, Retail has recurring electricity and/or natural gas sales in 19 U.S. states, the District of Columbia, and 2 provinces in Canada. Retail's brands, collectively, are the largest providers of electricity in Texas.

Residential and small commercial (Mass Market) consumers make purchase decisions based on a variety of factors, including price, customer service, brand, product choices and value-added features. These consumers 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, Retail is able to attract, retain, and increase the value of its customer relationships. Retail's brands are recognized for exemplary customer service, innovative smart energy and technology product offerings and environmentally friendly solutions.

Included in Retail is the Company's Business Solutions group, which includes demand response, commodity sales, energy efficiency and energy management solutions. An integrated provider of supply and distributed energy resources, Business Solutions focuses on 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 advisory services. 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. In 2018, Business Solutions delivered approximately 21 TWhs of electricity and managed approximately 2,000 MWs of demand response positions across its portfolio.

Generation

The Company’s wholesale power generation business includes plant operations, commercial operations, EPC, asset management, energy services and other critical related functions.

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 reliability services. The Company owns a diversified power generation portfolio with approximately 23,000[(a)] MW of fossil fuel, nuclear and renewable generation capacity at 37 plants as of December 31, 2018. In addition, the Company operates approximately 8,200 MW of coal and natural gas generation at 17 plants on behalf of third parties as of December 31, 2018. 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. Many of NRG's generation facilities are located near population centers, which often translates into higher revenue. Additionally, NRG's peaking facilities provide opportunities to capture significant upside potential during periods of high demand, which typically drive higher energy prices.

(a) excluding discontinued operations and held for sale

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, 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 higher wholesale pricing as a result of relatively favorable local supply-demand balance. The Company believes that its extensive generation portfolio provides asset optimization opportunities. NRG continuously evaluates opportunities for development of new generation, on both a merchant and contracted basis.

NRG Operations

The NRG businesses described above are 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, net capacity and retail capabilities as of December 31, 2018, excluding discontinued operations:

The following table summarizes NRG's global generation portfolio as of December 31, 2018:

	Global Generation Portfolio[a][b][c] (In MW)			
	Generation			
Generation Type	Texas[f]	East/West[d][e]	Other	Total Global
Natural gas	4,739	5,248	—	9,987
Coal	4,174	3,745	—	7,919
Oil	—	3,621	—	3,621
Nuclear	1,126	—	—	1,126
Wind	—	75	—	75
Utility Scale Solar	—	322	—	322
Battery Storage & Distributed Solar	2	—	60	62
Total generation capacity	10,041	13,011	60	23,112

(a) 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) The NRG Yield Inc. and the Renewables Platform businesses, which represented 3,428 MW of global generation, were sold on August 31, 2018
(c) Excludes the South Central Portfolio, except for Cottonwood, which was sold on February 4, 2019, as well as the 528 MW natural gas-fired project in Carlsbad, California that was sold on February 27, 2019
(d) Includes the 1,263 MW Cottonwood facility that was sold to Cleco on February 4, 2019, which the Company is leasing until 2025
(e) Includes International and Renewables
(f) Does not include plants outside of the ERCOT market or the Sherbino wind farm, which are included in East/West

The Company 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. This offsetting nature, 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.

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 2022. In addition, NRG's cleared capacity revenues not only enhance the reliability of future cash flows but are not correlated to natural gas prices during the contracted period. As of December 31, 2018, the Company had purchased fuel forward under fixed price contracts, with contractually-specified price escalators, for approximately 68% of its expected coal requirement from 2019 to 2020. The Company enters into additional hedges when it believes market conditions are favorable.

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 transmission rights, emissions allowances, renewable energy credits, fuel supplies and transportation-related services. The Company's principal objectives are the realization of the full market value of its overall portfolio, 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 supply contracts, 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 purchases and sales contracts to manage the commodity price risk. The objective of these hedging strategies is to stabilize the cash flow generated by NRG's overall portfolio.

In addition to power purchases and sales and hedging arrangements, NRG trades electric power, natural gas and related commodity and financial products, including forwards, futures, options and swaps. 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.

Retail Operations

NRG's retail businesses sell 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 five years while industrial contracts are often between one year and five years in length. In 2018, NRG's retail businesses sold approximately 67 TWhs of electricity and 11 MDth of natural gas. In any given year, the quantity of TWhs and MDth sold can be affected by weather, economic conditions and competition. The wholesale supply is typically purchased as the anticipated load is contracted from a combination of NRG's wholesale portfolio and other third parties. The ability to choose supply from the market or the Company's portfolio allows for an optimal combination to support and stabilize retail margins.

Capacity and Other Contracted Revenue Sources

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

Capacity auctions — The Company's largest sources of capacity revenues are capacity auctions in PJM and ISO-NE. Both PJM and ISO-NE 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.

2021/2022 PJM Auction Results — On May 23, 2018, PJM announced the results of its 2021/2022 base residual auction. NRG cleared approximately 4,619 MW of Capacity Performance product for the generation fleet. NRG's expected capacity revenues from the base residual auction for the 2021/2022 delivery year are approximately $322 million. The table below provides a detailed description of NRG’s 2021/2022 base residual auction results from May 23, 2018:

Zone	Generation Cleared Capacity (MW)	Price ($/MW-day)
COMED	3,995	$ 195.55
EMAAC	552	$ 165.73
PEPCO	72	$ 140.00
Total	4,619	

NRG through its demand response business received a capacity award of 3,194 MWs at a volume weighted average price of $155.16 per MW-day, or $181 million of revenue, and pays out a portion of these revenues to our customers reflected as cost of sales.

2022/2023 ISO-NE Auction Results - On February 6, 2019 ISO-NE announced the results of its 2022/2023 forward capacity auction. NRG cleared 1,517 MW of capacity. NRG's expected capacity revenues from the auction for the 2022/2023 delivery year are approximately $69 million.

Resource adequacy and bilateral contracts — In California, there is a resource adequacy requirement which is primarily satisfied through bilateral contracts. Such bilateral contracts are typically short-term resource adequacy contracts. When bilateral contracting does not satisfy the resource adequacy need, such shortfalls can be addressed through procurement tools administered by the CAISO, including the capacity procurement mechanism or reliability must-run contracts.

Bilateral contracts — The Company enters into physical power bilateral contracts for the sale of energy from our generation fleet as part of the Company's portfolio optimization strategy. Counterparties to the contracts are either third parties or our Retail segment. The Company primarily sells physical capacity forward through bilateral contracts for our New York assets. To the extent NRG is not able to enter into a physical bilateral contract, NRG will sell the remaining capacity into the NYISO six month strip, monthly or spot auctions.

Fuel Supply and Transportation

NRG's fuel requirements consist of various forms of fossil fuel (including coal, natural gas and oil) and nuclear fuel. The prices of fossil fuels are highly volatile. The Company obtains its fossil fuels from multiple suppliers and through multiple transporters. 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 businesses and fuel products used.

Coal — The Company believes it is adequately hedged, using forward coal supply agreements, for its domestic coal consumption for 2019. NRG actively manages its coal requirements based on forecasted generation, market volatility and its inventory on site. As of December 31, 2018, NRG had purchased forward contracts to provide fuel for approximately 68% of the Company's expected requirements from 2019 through 2020. NRG purchased approximately 23 million tons of coal in 2018, almost all of which was Powder River Basin coal. For fuel transport, NRG has entered into various rail and barge transportation and rail car lease agreements with varying tenures that provide for most of the Company's transportation requirements of Powder River Basin coal for the next 2 years.

The following table shows the percentage of the Company's coal requirements from 2019 through 2020 that have been purchased forward as of December 31, 2018:

	Percentage of Company's Requirement	
2019	100	%
2020	36	%

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 these types of 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 original 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. Since the operating license was renewed for another 20 years in September 2017, STPNOC has begun to review a second phase of fuel purchasing.

Operational Statistics

Retail

The following are industry statistics for the Company's customer count, load and economic gross margin per MWh:

	Years ended December 31,		
	2018	2017	2016
Sales volumes (in GWh)			
Mass electricity - Texas	37,846	36,169	35,102
Mass electricity - All other regions	7,968	6,221	6,764
C&I electricity - Texas	20,192	19,586	17,540
C&I electricity - All other regions	984	814	1,366
Total Load	66,990	62,790	60,772
Customer count - Electricity (in thousands)			
Texas			
Average Retail Mass	2,176	2,139	2,058
Ending Retail Mass	2,291	2,159	2,102
All other regions			
Average Retail Mass	790	675	679
Ending Retail Mass	903	673	671
Customer count - Natural gas (in thousands)			
Average Retail Mass	64	11	8
Ending Retail Mass	99	15	9
Gross margin and economic gross margin			
Gross margin (in millions)	$2,055	$1,778	$2,006
Economic gross margin (in millions)	1,802	1,602	1,649
Gross margin per MWh	30.68	28.32	33.01
Economic gross margin per MWh	26.91	25.51	27.13
Customer contract mix			
Term	65 %	70 %	70 %
Variable	25 %	22 %	23 %
Indexed	10 %	8 %	7 %
	100 %	100 %	100 %

Generation

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 global power generation portfolio, including leased facilities and those accounted for through equity method investments, for the years ended December 31, 2018 and 2017:

	Year Ended December 31, 2018				
			Fossil and Nuclear Plants [a]		
	Net Owned Capacity (MW)	Net Generation (MWh) (In thousands) [a]	Annual Equivalent Availability Factor	Average Net Heat Rate BTU/kWh	Net Capacity Factor
Generation					
Texas	10,161	38,214	85.2%	10,423	44.7 %
East/West/Other [b]	13,037	21,089	82.8%	9,711	17.8 %
Other [c]	60				

	Year Ended December 31, 2017				
			Fossil and Nuclear Plants [a]		
	Net Owned Capacity (MW)	Net Generation (MWh) (In thousands) [a]	Annual Equivalent Availability Factor	Average Net Heat Rate BTU/kWh	Net Capacity Factor
Generation					
Texas	10,159	38,694	90.4%	10,490	45.0 %
East/West/Other [b]	14,594	21,338	84.7%	9,738	16.4 %
Other [c]	114				

(a) Net generation excludes equity method investments

(b) Includes International, NRG renewable assets, Sherbino and the 1,263 MW Cottonwood facility, which NRG will lease back

(c) The net capacity figure within "Other" includes the aggregate production capacity of installed and activated residential solar energy systems

The generation performance by region for the three years ended December 31, 2018, 2017 and 2016, is shown below:

	Net Generation		
	2018	2017	2016
	(In thousands of MWh)		
Generation			
Texas			
Coal	24,781	24,757	21,738
Gas	4,415	4,428	6,379

Nuclear [a]	9,018	9,509	9,559
Total Texas	38,214	38,694	37,676
East/West			
Coal	7,965	8,403	9,931
Oil	544	319	318
Gas	11,797	10,949	11,671
Renewables	783	1,667	1,828
Total East/West	21,089	21,338	23,748

(a) MWh information reflects the Company's undivided interest in total MWh generated by STP

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Greenhouse Gas Emissions — NRG emits CO_2 and small quantities of other GHGs (0.6% of total) when generating electricity at a majority of its facilities. The graphs presented below illustrate NRG's domestic emissions of CO_{2e} for the 2014 through 2018 period. A significant majority (>99%) of NRG's emission sources are subject to federal (U.S. EPA) GHG reporting requirements programs. From 2014 to 2018, the Company's CO_{2e} emissions decreased from 72 million metric tons to 46 million metric tons, representing a 36% reduction. The primary factor leading to the decreased emissions include reductions in fleet net generation due to a market-driven shift from coal as a primary fuel to natural gas. The Company's goal is to reduce CO_{2e} emissions by 50% by 2030, and 90% by 2050, using 2014 as a baseline.

As of December 31, 2018, less than 25% of the Company's consolidated operating revenues were derived from coal-fired operating assets.

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 and actions of the current U.S. presidential administration.

Segment Review

The Company's segment structure reflects how management currently makes financial decisions and allocates resources. The Company's businesses are segregated as follows: Retail, which includes Mass customers and Business Solutions, which includes C&I customers and other distributed and reliability products; and Generation, which includes all power plant activities, domestic and international, as well as renewables. Intersegment sales are accounted for at market. The Company has recast data from prior periods to reflect changes in reportable segments to conform to the current year presentation.

As further described in Note 3, Acquisitions, Discontinued Operations and Dispositions, the Company is treating the following businesses as discontinued operations, which have been recast to present in the corporate segment:

- •South Central Portfolio
- •NRG Yield, Inc. and its Renewables Platform
- •Carlsbad
- •GenOn

Revenues

The following table contains a summary of NRG's operating revenues by segment for the years ended December 31, 2018, 2017 and 2016, as discussed in Item 15 — Note 17, Segment Reporting, to the consolidated financial statements. Refer to that footnote for additional financial information about NRG's business segments including a profit measure and total assets. In addition, refer to Item 2 — Properties, to the consolidated financial statements for information about facilities in each of NRG's business segments.

	Year Ended December 31, 2018						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amortization	Other Revenues[(a)]	Total Operating Revenues[(b)]
	(In millions)						
Generation	$2,677	$ 670	$ —	$ (202)	$ —	$ 287	$ 3,432
Retail	—	—	7,110	(7)	—	—	7,103
Corporate and Eliminations [(b)]	(1,129)	—	(5)	79	—	(2)	(1,057)
Total	$1,548	$ 670	$ 7,105	$ (130)	$ —	$ 285	$ 9,478

(a) Consists operation and maintenance revenues and unrealized trading activities, primarily at BETM (Generation segment)

(b) Energy revenues include inter-segment sales primarily between Generation and Retail

	Year Ended December 31, 2017						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amortization	Other Revenues[(c)]	Total Operating Revenues[(d)]
	(In millions)						
Generation	$2,725	$ 618	$ —	$ 37	$ —	$ 235	$ 3,615
Retail	—	—	6,374	(4)	(1)	—	6,369
Corporate and Eliminations [(d)]	(1,089)	(6)	4	219	—	(38)	(910)
Total	$1,636	$ 612	$ 6,378	$ 252	$ (1)	$ 197	$ 9,074

(c) Consists of operation and maintenance revenues and energy service revenues, primarily at BETM (Generation segment)

(d) Energy revenues include inter-segment sales primarily between Generation and Retail

	Year Ended December 31, 2016						
	Energy Revenues	Capacity Revenues	Retail Revenues	Mark-to-Market Activities	Contract Amortization	Other Revenues[(e)]	Total Operating Revenues[(f)]
	(In millions)						
Generation	$3,243	$ 642	$ —	$ (565)	$ —	$ 313	$ 3,633

Retail	—	—	6,332	(1)	(1)	—	6,330
Corporate and Eliminations[f]	(974)	(5)	36	(70)	—	(35)	(1,048)
Total	$2,269	$ 637	$ 6,368	$ (636)	$ (1)	$ 278	$ 8,915

(e) Consists of operation and maintenance revenues and energy service revenues, primarily at BETM (Generation segment)

(f) Energy revenues include inter-segment sales primarily between Generation and Retail

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.

Market Framework

Retail

NRG's retail businesses sell 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 consumer choice, NRG's retail businesses competitively offer retail power, natural gas, portable power and other value-enhancing services to end-use customers. Each retail choice state establishes its own retail competition laws and regulations, and the specific operational, licensing, and compliance requirements vary on a state-by-state basis. In the East markets, incumbent utilities currently provide default service and as a result typically serve a majority of residential customers. In Texas, NRG’s retail business activities 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. A majority of the retail 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. 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 in each state across the country.

Wholesale

NRG's fleet operates in 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.

Texas

NRG's Texas wholesale power generation business is located in the ERCOT market. The ERCOT market is one of the nation's largest and historically fastest growing power markets. ERCOT is an energy- only market, and has implemented market rule changes referred to as the Operating Reserve Demand Curve (ORDC) to provide pricing more reflective of higher energy value when operating reserves are scarce or constrained. The PUCT directed the implementation of the ORDC in 2014 to act as the primary scarcity pricing mechanism and has modified it several times since then, including as recently as January 2019.

East/West

NRG's generation and demand response assets located in the East region of the U.S. are within the control areas of ISO-NE, MISO, 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, the East region receives a significant portion of its revenues from capacity markets in ISO-NE, MISO, NYISO and PJM. PJM and ISO-NE use a three-year forward capacity auction, while NYISO uses a month-ahead capacity auction. MISO has an annual auction, known as the Planning Resource Auction. 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 prices times the quantity of MWs cleared, plus the net of any over-performance "bonus payments" and any under-performance charges. In both markets, bidding rules allow for the incorporation of a risk premium into generator bids.

In the West region, NRG 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 sales 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 Company’s Agua Caliente and Ivanpah projects are party to PPAs with PG&E. Both projects have project financing with the U.S. DOE, and Agua Caliente Borrower 1 LLC, along with Agua Caliente Borrower 2 LLC, which is owned by Clearway Energy Inc., are party to a back leverage financing related to the Agua Caliente project. On January 29, 2019, PG&E Corp. and subsidiary utility PG&E filed for Chapter 11 bankruptcy protection. For further discussion see Item 1 - Energy Regulatory Matters, Note 11 - Debt and Capital Leases and Note 15 - Investments Accounted for by the Equity Method and Variable Interest Entities.

Energy Regulatory Matters

As owners of power plants and participants in retail and wholesale 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 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 NERC and the regional reliability entities in the regions where NRG 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 NRG's ownership interest in STP.

Federal Energy Regulation

Complaints Ahead of PG&E Corporation Bankruptcy Filing — On January 18, 2019, NextEra filed a petition for declaratory order requesting that FERC assert its jurisdiction over PG&E's wholesale contracts prior to PG&E's formal bankruptcy filing. Exelon Corporation and EDF Renewables filed similar complaints. On January 25, 2019, FERC found that it and the bankruptcy courts have concurrent jurisdiction to review and address the disposition of wholesale power contracts. The matter is in litigation.

State Energy Regulation

State Out-Of-Market Subsidy Proposals — NRG has opposed efforts to provide out-of-market subsidies and intends to continue opposing them in the future. NRG has petitioned the Supreme Court of the United States to hear cases from the Seventh and Second Circuit Courts regarding ZECs in Illinois and New York, respectively. NRG is also currently participating in the NJBPU's proceeding regarding ZECs, and is involved in the informational meetings that the PA PUC is holding regarding the nuclear subsidy issue.

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 22, Regulatory Matters, to the Consolidated Financial Statements.
PJM
Capacity Market Reforms Filing — FERC is considering various proposals to reform the PJM capacity market, including whether to accommodate state subsidies in the wholesale market or to mitigate subsidized resources, along with other changes. As part of this process, FERC established a procedural timetable and delayed the 2019 Base Residual Auction until August 2019. Decisions around harmonizing federal and state policy initiatives is a critical factor for setting future prices.
New England
ISO-NE Retention of Mystic Units — ISO-NE is currently engaged in extensive litigation at FERC regarding how to ensure system reliability in a gas-constrained system. In particular, FERC has approved ISO-NE's proposal to retain units at the Mystic generating station, which utilizes liquefied natural gas for fuel security. Among other things, FERC specifically will allow resources retained for fuel security to enter a zero bid in the Forward Capacity Auction. On January 2, 2019, multiple parties filed for rehearing. The motions for rehearing are pending at FERC. The outcome of this matter will potentially affect future capacity market prices.
New York
Independent Power Producers of New York Complaint — A variety of generators have requested that FERC address the market impacts of out-of-market payments to existing generation in the NYISO. This request was prompted by the ZEC program initiated by the NYSPSC in 2013, with various requests for FERC to act since. 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 be mitigated. Failure to implement buyer-side mitigation measures could result in uneconomic entry, which artificially decreases capacity prices below competitive market levels.
New York Public Service Commission Retail Energy Market Proceedings — On February 23, 2016, the NYSPSC issued what it refers to as its "Retail Reset" order. Among other things, the Reset Order placed a price cap on energy supply offers and imposed burdensome new regulations on customers. Various parties have challenged the NYPSC's authority to regulate prices charged by competitive suppliers, and that litigation is ongoing.
Texas
ORDC Reforms — In January 2019, the PUCT directed ERCOT to implement changes to its scarcity pricing structure, known as the ORDC, which is designed to increase the likelihood of scarcity pricing to support existing generation and new investment. The PUCT directed ORDC reforms to be implemented in two phases of gradually increasing magnitude. The first phase will become effective prior to the summer of 2019 and the second phase will become effective prior to the summer of 2020.

Environmental Regulatory Matters
NRG is subject to numerous 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. Federal and state environmental laws historically have become more stringent over time. Future laws may require the addition of emissions controls or other environmental controls or impose restrictions on our operations, which could affect the Company's operations. Complying with environmental laws often involves significant capital and operating expenses, as well as occasionally curtailing operations. 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 that may affect the Company are under review by the EPA, including ESPS for GHGs, ash disposal requirements, NAAQS revisions and implementation and effluent limitation guidelines. NRG will evaluate the impact of these regulations as they are revised but cannot fully predict the impact of each until anticipated revisions and legal challenges are resolved.

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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 PM2.5. 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. The Company maintains a comprehensive compliance strategy to address continuing and new requirements. Complying with increasingly stringent air regulations could require the installation of additional emissions control equipment at some NRG facilities or retiring of units if installing such controls is not economic. Significant changes to air regulatory programs affecting the Company are described below.

MATS — In 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 had to be met beginning in April 2015. In December 2018, the EPA proposed a finding that regulating HAPs was not "appropriate and necessary" because the costs far exceed the benefits. Nonetheless, the EPA proposed keeping the substantive requirements of the MATS rule. 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 attention in recent years on GHG emissions has resulted in federal regulations and state legislative and regulatory action. In October 2015, the EPA finalized the CPP, addressing GHG emissions from existing EGUs. On February 9, 2016, the U.S. Supreme Court stayed the CPP. The D.C. Circuit heard oral argument on the legal challenges to the CPP in September 2016. At the EPA's request, the D.C. Circuit agreed on April 28, 2017 to hold the case in abeyance. On October 16, 2017, the EPA proposed a rule to repeal the CPP. In August 2018, the EPA published the proposed Affordable Clean Energy, or ACE, rule to replace the CPP. The ACE rule proposes that the EPA would provide guidelines for states to in turn require heat rate improvements at coal-fired EGUs to reduce GHG emissions.

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. In September 2017, the EPA agreed to reconsider the rule. On July 30, 2018, the EPA promulgated a rule that amends the existing ash rule by extending some of the deadlines and providing more flexibility for compliance. On August 21, 2018, the D.C. Circuit found, among other things, that the EPA had not adequately regulated unlined ponds and legacy ponds. Accordingly, we anticipate that the EPA will promulgate new regulations to address these issues (including compliance deadlines) as it reconsiders other aspects of the existing rule. The EPA has stated that it intends to further revise the rule. The Company will provide estimates of the cost of compliance after the rule is revised.

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws, a current or previous owner or operator of a 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. 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 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 23, 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 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. On December 12, 2016, STPNOC received the federal government's offer of another three-year extension of payment for continued failure to accept SNF and HLW. The proposal was reviewed and accepted. 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.

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

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 have become more stringent and imposed new requirements.

Once Through Cooling Regulation — 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. While 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, the Company anticipates the cost of complying with these restrictions to be immaterial.

Effluent Limitations Guidelines — In November 2015, the EPA revised the Effluent Limitations Guidelines for Steam Electric Generating Facilities, which would have imposed more stringent requirements (as individual permits were renewed) for wastewater streams from flue gas desulfurization, fly ash, bottom ash, and flue gas mercury control. In April 2017, the EPA granted two petitions to reconsider the rule and also administratively stayed some of the deadlines. On September 18, 2017, the EPA promulgated a final rule that (i) postpones the compliance dates to preserve the status quo for FGD wastewater and bottom ash transport water by two years to November 2020 until the EPA completes its next rulemaking and (ii) withdrew the April 2017 administrative stay. The legal challenges have been suspended while the EPA reconsiders and likely modifies the rule. Accordingly, the Company has eliminated its estimate of the environmental capital expenditures that would have been required to comply with permits incorporating the revised guidelines. The Company will revisit these estimates after the rule is revised.

Regional Environmental Developments

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, or the VCP. 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, the Company's Closure Report and the Company's Long Term Stewardship Plan. The cost of completing the work required by the approved remediation plan is consistent with amounts budgeted in early 2016 and remediation was completed in 2017. The estimated cost to comply with the Long-Term Stewardship Plan was added to the liability in 2016.

In addition to the VCP, 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 working with DNREC and other trustees to close out the assessment process.

Customers

NRG sells to a wide variety of customers. ERCOT accounted for 11% of NRG's total revenue in 2018. 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. NRG also receives significant revenues from PJM in its capacity as the regional transmission organization for the PJM footprint.

Employees

As of December 31, 2018, NRG and its consolidated subsidiaries had 4,862 employees, approximately 26% of whom were covered by U.S. bargaining agreements. During 2018, 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, sustainability reports and other information regarding the Company on the Company's website. The information posted on the Company's website is not a part of this report.

Item 1A — Risk Factors Related to NRG Energy, Inc.
Risks Related to the Operation of NRG's Business
NRG adopted and initiated the Transformation Plan. If the Transformation Plan does not achieve its expected benefits, there could be negative impacts to NRG’s business, results of operations and financial condition.

NRG adopted and initiated the Transformation Plan, designed to significantly strengthen earnings and cost competitiveness, lower risk and volatility, and create significant shareholder value. The three-part, three-year plan is comprised of the following components: (i) operations and cost excellence; (ii) portfolio optimization; and (iii) capital structure and allocation enhancements.

NRG may be unable to fully implement the components of the Transformation Plan, in which case, NRG would not realize the anticipated benefits. Alternatively, such components of the Transformation Plan, even if implemented, may not result in the anticipated benefits to NRG’s business, results of operations and financial condition in a timely manner if at all. Further, NRG could experience unexpected delays, business disruptions resulting from supporting these initiatives during and following completion of these activities, decreased productivity, adverse effects on employee morale and employee turnover as a result of such initiatives, any of which may impair NRG’s ability to achieve anticipated results or otherwise harm NRG’s business, results of operations and financial condition.

NRG's financial performance may be impacted by price fluctuations in the retail and wholesale power and natural gas markets, as well as fluctuations in coal and oil markets and other market factors that are beyond the Company's control.
Market prices for power, 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 as a result of the development of new plants, expansion of existing plants, the continued operation of uneconomic power plants due to state subsidies, 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;
- changes in law, including judicial decisions;
- weather conditions, including extreme weather conditions and seasonal fluctuations, including the effects 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, new technologies and new forms of competition 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 prices related to RECs; and
- changes in capacity prices and capacity markets.

While retail rates are generally designed to allow retail sellers of electricity and natural gas to pass through price fluctuations, the Company may not be able to pass through all such fluctuations to customers. For example, the Company engages in some sales of power at fixed prices. Additionally, increases in wholesale costs to retail customers may cause additional customer defaults or increased customer attrition, or may be limited by regulatory rules.

Such factors and the associated fluctuations in power prices have affected the Company's wholesale and retail profitability in the past and will continue to do so in the future.
Some of NRG's businesses operate, wholly or partially, without long-term power sale agreements.
Some of NRG's businesses operate without long-term contracts. In retail, many of NRG’s customers are contracted for a period of one year or less, and NRG may or may not hedge its retail power sales exposure, or may hedge in a manner that is not effective at managing quantity or price risk in the retail market. In generation, 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 or purchase agreements, and without long-term load obligations, NRG cannot be sure that it will be able to sell or purchase power at commercially attractive rates or that its generation facilities will be able to operate profitably. This could lead to future impairments of the Company's property, plant and equipment, the closing of certain of its facilities or the loss of retail customers, which could have a material adverse effect on the Company's results of operations, financial condition or cash flows.
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 different products, 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 and strong 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'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. Its retail operations can likewise be affected by changes in commodity costs. Grid operations depend on 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 generation facilities and to ensure that there is sufficient power produced to meet retail demand. As a result, the Company’s wholesale generating facilities are 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. The Company’s retail operations are likewise subject to many of the same constraints.
NRG routinely hedges both its wholesale sales and purchases to support its retail load obligations. In order to hedge these obligations, the Company may enter 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 or power supply arrangements may therefore require it to find alternative fuel sources at higher costs, to find other sources of power to deliver to retail customers or other counterparties at a higher cost, or to pay damages to counterparties for failure to deliver power or sell electricity or natural gas as contracted. Any such event could have a material adverse effect on the Company's financial performance.

NRG also buys significant quantities of electricity and fuel on a short-term or spot market basis. Prices sometimes rise or fall 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. Retail rates may also not rise at the same rate, or may not rise at all. This may have a material adverse effect on the Company's financial performance.
Changes in market prices for electricity, 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.
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.

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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, to manage the commodity price risks inherent in its power generation and retail operations. The Company’s risk management policies and hedging procedures may not mitigate risk as planned, and the Company may fail to fully or effectively hedge its commodity supply and price risk. In addition, these activities, although intended to mitigate price volatility, expose the Company to other risks. When the Company sells or buys power forward, it gives up the opportunity to buy or sell power at the future price, 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.

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

The Company may sell 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.

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NRG may not have sufficient liquidity to hedge market risks effectively.
The Company is exposed to market risks through its retail and wholesale business, which involves the purchase of electricity for resale, 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 or 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 depend 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, or if retail customers use more power than expected, the Company may be required to procure additional power at spot market prices 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, as well as retail sales of electricity.
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 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. New parties may offer retail electricity bundled with other products or at prices that are below the Company’s rates. Because many of the Company's facilities are older, 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.
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 retail sales or greater flexibility in the timing of their sale of generation capacity and ancillary services than NRG does. Competitors may

also have better access to subsidies or other out-of-market payments that put NRG at a competitive disadvantage.

NRG's competitors may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to marketing of retail power 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.

In addition, NRG provides plant operations and commercial services to a variety of third-parties. There is a risk that mistakes, mis-operations, or actions taken by these third-parties could be attributed to NRG, including the risk of investigation or penalties being assessed to NRG in connection with the services it offers, or that regulators could question whether NRG had the appropriate safeguards in place.

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 require periodic 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.

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.

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, chemicals 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 may rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. The Company has also hedged a portion of its exposure to power price fluctuations through forward fixed price power sales and natural gas price swap agreements. Counterparties to these agreements may breach or may be unable to perform their obligations. NRG may not be able to enter into replacement agreements on terms as favorable as its existing agreements, or at all. If the Company was unable to enter into replacement PPAs, the Company would sell its plants' power at market prices. If the Company is unable to enter into replacement fuel or fuel transportation purchase agreements, NRG would seek to purchase the Company's fuel requirements at market prices, exposing the Company to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price.

The failure of any supplier or customer to fulfill its contractual obligations to NRG could have a material adverse effect on the Company's financial results. Consequently, the financial performance of the Company's facilities is dependent on the credit quality of, and continued performance by, suppliers and customers.

NRG relies on power transmission and distribution facilities that it does not own or control and that are subject to transmission constraints within a number of the Company's core regions.

NRG depends on transmission and distribution facilities owned and operated by others to deliver wholesale power sales and retail power sales to its customers. If transmission or distribution is disrupted, including by force majeure events, or if the transmission or distribution infrastructure is inadequate, NRG's ability to sell and deliver wholesale power may be adversely impacted. The Company also cannot predict whether transmission or distribution 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 associated with wholesale power sales or purchases, or retail sales, particularly where the Company’s load is not co-located with its retail sales obligations. If NRG were liable for such congestion costs, the Company's financial results could be adversely affected.

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 or disposition activities could involve unknown risks and may have materially adverse effects and NRG may be subject to trailing liabilities from businesses that it disposes of or that are inactive.

NRG may in the future make acquisitions or dispositions of businesses or assets, acquire or sell books of retail customers, or pursue other business activities, directly or indirectly through subsidiaries, that involve a number of risks. 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 or customers, 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. In the case of dispositions, such risks may relate to employment matters, counterparties, regulators and other stakeholders in the disposed business, risks relating to separating the disposed assets from NRG’s business, risks related to the management of NRG’s ongoing business, risks unknown to NRG at the time, and other financial, legal and operational risks related to such disposition. In addition, NRG may be subject to material trailing liabilities from disposed businesses such as Clearway Energy Inc., and its Renewables Platform. Any such risk may result in one or more costly disputes or litigation. 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. There can also be no assurances that NRG will realize the anticipated benefits from any such dispositions. The failure to realize the anticipated returns or benefits from an acquisition or disposition could adversely affect NRG's results of operations, cash flows and financial condition.

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, 2018, approximately 26% 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 and the attractiveness of its retail products.

Research and development activities are ongoing to provide alternative and more efficient technologies to produce power, including 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. Technology, including distributed technology or changes in retail rate structures, may also have a material impact on the Company’s ability to retain retail customers.

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 emerging technologies like distributed renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices could affect the price of energy. These emerging technologies may affect the financial viability of utility counterparties and could have significant impacts on wholesale market prices, which could ultimately have a material adverse effect on NRG's financial condition, results of operations and cash flows.

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 depend 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 rely 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, driver's 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 energy 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 energy 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, reduce the Company's ability to sell retail power within certain states or to certain classes of retail customers; or restrict the Company’s marketing practices, its ability to pass through costs to retail customers, or its ability to compete on favorable terms with competitors, including the incumbent utility. Retail competition is regulated on a state-by-state level and is highly dependent on state laws, regulations and policies, which could change at any moment.

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 reinstate the vertical monopoly utility of the markets or require divestiture by generating companies to reduce their market share. 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.

NRG’s business may be affected by state interference in the competitive wholesale marketplace.

NRG’s generation and competitive retail businesses rely on a competitive wholesale marketplace. The competitive wholesale marketplace may be impacted by out-of-market subsidies provided by states or state entities, including bailouts of uneconomic nuclear plants, imports of power from Canada, renewable mandates or subsidies, mandates to sell power below its cost of acquisition and associated costs, as well as out-of-market payments to new or existing generators. These out-of-market subsidies to existing or new generation undermine the competitive wholesale marketplace, which can lead to premature retirement of existing facilities, including those owned by the Company. If these measures continue, capacity and energy prices may be suppressed, and the Company may not be successful in its efforts to insulate the competitive market from this interference. The Company's retail businesses may be materially impacted by rules or regulations that allow regulated utilities to participate in competitive retail markets or own and operate facilities that could be provided by competitive market participants.

The integration of the Capacity Performance product into the PJM market and the Pay-for-Performance mechanism in ISO-NE 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.

Both ISO-NE and PJM operate a pay-for-performance model where capacity payments are modified based on real-time generator performance. Capacity market prices are sensitive to design parameters, as well as additions of new capacity. NRG 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.

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, 2047 (Unit 1) and December 15, 2048 (Unit 2).

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. 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 21, 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. Federal and state environmental laws generally have become more stringent over time. 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.

NRG's businesses are subject to physical, market and economic risks relating to potential effects of climate change. Fluctuations in weather and other environmental conditions, including temperature and precipitation levels, may affect 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 supply chain, and cause them 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. NRG's commercial and residential customers may also experience the potential physical impacts of climate change and may incur significant costs in preparing for or responding to these efforts, including increasing the mix and resiliency of their energy solutions and supply.

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. NRG monitors water risk carefully. If it is determined that a water supply risk exists that could impact projected generation levels at any plant risk mitigation efforts are identified and evaluated for implementation.

GHG regulation could increase the cost of electricity generated by fossil fuels, and such increases could reduce demand for the power NRG generates and markets. Also, demand for NRG's energy-related services could be similarly impacted 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 mitigate climate change, could adversely impact NRG's results of operations, financial condition and cash flows.

NRG's GHG emissions for 2018 can be found in Item 1, Business — Operational Statistics. In 2015, the EPA promulgated the final GHG emissions rules for new and existing fossil-fuel-fired electric generating units, which have been stayed by the U.S. Supreme Court and the EPA has proposed repealing.

The Company operates generating units in Connecticut, Delaware, Maryland, and New York which are subject to RGGI, which is a regional cap and trade system for CO2. In 2013, each of these states finalized a rule that reduced and will continue to reduce the number of allowances through 2020. The nine RGGI states re-evaluated the program and published a model rule to further reduce the number of allowances. The 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.

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. The contribution of climate change to the frequency or intensity of weather-related events could affect NRG's operations and planning process.

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 partially depends 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. The Company's retail businesses may be materially impacted by rules or regulations that allow regulated utilities to participate in competitive retail markets or own and operate facilities that could be provided by competitive market participants. 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. 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 depend on 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. 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.

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.

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:

- NRG's ability to achieve the expected benefits of its Transformation Plan;
- NRG's ability to engage in successful sales and divestitures as well as mergers and acquisitions activity;
- NRG's ability to obtain and maintain retail market share;
- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- Volatile power supply costs and demand for power;
- Changes in law, including judicial decisions;
- 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 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 changes in market rules, rates, tariffs and environmental laws;
- 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 for units subject to capacity performance requirements in PJM, performance incentives in ISO-NE, and scarcity pricing in ERCOT;
- 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;
- 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;
- Cyber terrorism and inadequate cybersecurity, or the occurrence of a catastrophic loss and the possibility that NRG may not have adequate insurance to cover losses resulting from such hazards or the inability of NRG's insurers to provide coverage;
- NRG's ability to develop and build new power generation facilities;
- 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 increase cash from operations through operational and commercial initiatives, corporate efficiencies, asset strategy, and a range of other programs throughout NRG to reduce costs or generate revenues;
- NRG's ability to achieve its strategy of regularly returning capital to stockholders;
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NRG's ability to successfully evaluate investments and achieve intended financial results in new business and growth initiatives;

- NRG's ability to successfully integrate, realize cost savings and manage any acquired businesses; and
- NRG's ability to develop and maintain successful partnering relationships.

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

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Listed below are descriptions of NRG's interests in facilities, operations and/or projects owned or leased as of December 31, 2018. 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, 2018. The following table summarizes NRG's power production and cogeneration facilities by region:

Name of Facility	Power Market	Plant Type	Primary Fuel	Location	Rated MW Capacity	Net MW Capacity[(a)]	% Owned
Texas							
Cedar Bayou	ERCOT	Fossil	Natural Gas	TX	1,494	1,494	100.0
Cedar Bayou 4	ERCOT	Fossil	Natural Gas	TX	504	252	50.0
Elbow Creek	ERCOT	Other	Battery Storage	TX	2	2	100.0
Greens Bayou	ERCOT	Fossil	Natural Gas	TX	330	330	100.0
Gregory	ERCOT	Fossil	Natural Gas	TX	365	365	100.0
Limestone	ERCOT	Fossil	Coal	TX	1,660	1,660	100.0
Petra Nova Cogen	ERCOT	Fossil	Natural Gas	TX	38	19	50.0
San Jacinto	ERCOT	Fossil	Natural Gas	TX	160	160	100.0
South Texas Project[(b)]	ERCOT	Nuclear	Uranium	TX	2,559	1,126	44.0
T.H. Wharton	ERCOT	Fossil	Natural Gas	TX	1,001	1,001	100.0
W.A. Parish	ERCOT	Fossil	Coal	TX	2,514	2,514	100.0
W.A. Parish	ERCOT	Fossil	Natural Gas	TX	1,118	1,118	100.0
Total Texas					11,745	10,041	
East/West							
Agua Caliente	WECC	Renewable	Solar	AZ	290	102	35.0
Arthur Kill	NYISO	Fossil	Natural Gas	NY	865	865	100.0
Astoria Turbines	NYISO	Fossil	Natural Gas	NY	415	415	100.0
Chalk Point	PJM	Fossil	Natural Gas	MD	80	80	100.0
Connecticut Jet Power	ISO-NE	Fossil	Oil	CT	142	142	100.0
Cottonwood[(c)]	MISO	Fossil	Natural Gas	TX	1,263	1,263	100.0
Devon	ISO-NE	Fossil	Oil	CT	133	133	100.0
Doga		Fossil	Natural Gas	Turkey	180	144	80.0
Fisk	PJM	Fossil	Oil	IL	171	171	100.0
Gladstone		Fossil	Coal	AUS	1,613	605	37.5
Indian River	PJM	Fossil	Coal	DE	410	410	100.0
Indian River	PJM	Fossil	Oil	DE	16	16	100.0
Ivanpah	CAISO	Renewable	Solar	CA	393	214	54.5
Joliet[(e)]	PJM	Fossil	Natural Gas	IL	1,326	1,326	100.0
Long Beach	CAISO	Fossil	Natural Gas	CA	252	252	100.0
Middletown	ISO-NE	Fossil	Oil	CT	762	762	100.0
Midway-Sunset	CAISO	Fossil	Natural Gas	CA	226	113	50.0
Montville	ISO-NE	Fossil	Oil	CT	491	491	100.0
Oswego	NYISO	Fossil	Oil	NY	1,638	1,638	100.0
Powerton[(e)]	PJM	Fossil	Coal	IL	1,538	1,538	100.0
Sherbino Wind Farm	ERCOT	Renewable	Wind	TX	150	75	50.0
Stadiums		Renewable	Solar	various	6	6	100.0
Sunrise	CAISO	Fossil	Natural Gas	CA	586	586	100.0
Vienna	PJM	Fossil	Oil	MD	167	167	100.0

Watson	CAISO	Fossil	Natural Gas	CA	416	204	49.0
Waukegan	PJM	Fossil	Coal	IL	682	682	100.0

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Name of Facility	Power Market	Plant Type	Primary Fuel	Location	Rated MW Capacity	Net MW Capacity[(a)]	% Owned
Waukegan	PJM	Fossil	Oil	IL	101	101	100.0
Will County	PJM	Fossil	Coal	IL	510	510	100.0
Total East/West					14,822	13,011	
Other							
Residential solar		Renewable	Solar	various	60	60	100.0
Total Other					60	60	
Total Continuing Operations, excluding Held for Sale					26,627	23,112	
Held for Sale and Discontinued Operations							
Bayou Cove[(c)]	MISO	Fossil	Natural Gas	LA	225	225	100.0
Big Cajun I[(c)]	MISO	Fossil	Natural Gas	LA	430	430	100.0
Big Cajun II[(c)]	MISO	Fossil	Coal	LA	580	580	100.0
Big Cajun II[(c)]	MISO	Fossil	Natural Gas	LA	540	540	100.0
Big Cajun II[(c)]	MISO	Fossil	Coal	LA	588	341	58.0
Carlsbad[(f)]	CAISO	Fossil	Natural Gas	CA	528	528	100.0
Guam[(d)]	GPA	Renewable	Solar	Guam	26	26	100.0
Sterlington[(c)]	MISO	Fossil	Natural Gas	LA	176	176	100.0
Total Held for Sale and Discontinued Operations					3,093	2,846	
Total Fleet					29,720	25,958	

(a) 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

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

(c) Assets that are part of NRG's South Central Portfolio. The entire South Central Portfolio, including Cottonwood, was sold on February 4, 2019. NRG will continue to operate the Cottonwood facility under a lease agreement through 2025

(d) Guam was classified as held for sale as of December 31, 2018. The sale was completed on February 20, 2019

(e) 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

(f) On February 6, 2018, the Company entered into an agreement with NRG Yield, Inc. and GIP to sell 100% of NRG's membership interests in Carlsbad Energy Holdings LLC, which owns the Carlsbad project, a 528 MW natural gas-fired project in Carlsbad, California pursuant to the ROFO Agreement. The transaction closed on February 27, 2019

Other Properties

NRG owns several real properties and facilities related 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 at 804 Carnegie Center, Princeton, New Jersey, its operational headquarters in Houston, Texas, its retail business offices and call centers, and various other office space.

Item 3 — Legal Proceedings

See Item 15 — Note 21, 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 common stock and 10,000,000 shares of preferred stock. A total of 25,000,000 shares of the Company's common stock are authorized for issuance under the NRG LTIP. No shares of NRG common stock were available for future 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 19, Stock-Based Compensation, to the Consolidated Financial Statements.

NRG had 283,650,039 shares outstanding as of December 31, 2018. As of January 31, 2019, there were 280,997,550 shares outstanding, and there were 19,691 common stockholders of record.

NRG currently anticipates continuing to pay comparable cash dividends in the future.

Issuer Purchases of Equity Securities

In 2018, the Company's board of directors authorized the Company to repurchase $1.5 billion of its common stock. During the year ended December 31, 2018, the Company repurchased a total of 35,234,664 shares under these programs for $1.25 billion, and the remaining $250 million was repurchased by February 28, 2019. The average price paid per share for the $1.5 billion share repurchase was $36.24. In addition, the Company's board of directors authorized in February 2019 an additional $1.0 billion share repurchase program to be executed in 2019.

The table below sets forth the information with respect to purchases made by or on behalf of NRG or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act), of NRG's common stock during the quarter ended
December 31, 2018.

For the three months ended December 31, 2018	Total Number of Shares Purchased	Average Price Paid per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(b)]
Month #1 (October 1, 2018 to October 31, 2018)	—	$ —	—	$ 500,000,000
Month #2 (November 1, 2018 to November 30, 2018)	1,964,808	$ 38.59	1,964,808	$ 424,174,905
Month #3 (December 1, 2018 to December 31, 2018)[(c)]	4,725,163	$ 36.87	4,725,163	$ 249,951,196
Total at December 31, 2018	6,689,971	$ 37.38	6,689,971	

(a) The average price paid per share excludes commissions of $0.01 per share paid in connection with the open market share repurchases

(b) Includes commissions of $0.01 per share paid in connection with the open market share repurchases

(c) Includes 486,618 of additional shares delivered upon settlement of an ASR agreement executed in September 2018

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, 2013 through December 31, 2018 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, 2013, 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-2013	Dec-2014	Dec-2015	Dec-2016	Dec-2017	Dec-2018
NRG Energy, Inc.	$ 100.00	$ 95.52	$ 42.95	$ 45.71	$ 106.82	$ 149.10
S&P 500	100.00	113.69	115.26	129.05	157.22	150.33
UTY	100.00	128.94	120.87	141.90	160.09	165.72

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, Acquisitions, Discontinued Operations and Dispositions.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions except ratios and per share data)				
Statement of income data:					
Total operating revenues	$9,478	$9,074	$8,915	$10,842	$11,387
Total operating costs and other expenses [(a)]	(8,929)	(8,953)	(9,208)	(11,010)	(11,606)
Impairment losses [(b)]	(99)	(1,534)	(483)	(4,823)	(5)
Operating income/(loss)	982	(741)	33	(4,347)	537
Impairment losses on investments	(15)	(79)	(268)	(40)	—
Income/(loss) from continuing operations, net	460	(1,345)	(956)	(6,379)	(223)
(Loss)/income from discontinued operations, net	(192)	(992)	65	(57)	355
Net income/(loss) attributable to NRG Energy, Inc.	$268	$(2,153)	$(774)	$(6,382)	$134
Common share data:					
Basic shares outstanding — average	304	317	316	329	334
Diluted shares outstanding — average	308	317	316	329	339
Shares outstanding — end of year	284	317	315	314	337
Per share data:					
Net income/(loss) attributable to NRG — basic	$0.88	$(6.79)	$(2.22)	$(19.46)	$0.23
Net income/(loss) attributable to NRG — diluted	0.87	(6.79)	(2.22)	(19.46)	0.23
Dividends declared per common share	0.12	0.12	0.24	0.58	0.54
Book value	$(4.35)	$6.20	$14.09	$17.29	$34.68
Business metrics:					
Cash flow from operations	$1,377	$1,610	$1,908	$1,419	$1,620
Liquidity position [(c)]	1,977	2,760	1,768	2,102	2,136
Return on equity	(21.72)%	(109.40)%	(17.41)%	(117.45)%	1.15%
Ratio of debt to total capitalization	126.12%	81.40%	68.26%	63.96%	46.61%
Balance sheet data:					
Current assets	$3,600	$4,437	$6,747	$8,231	$9,454
Current liabilities	2,398	3,354	4,736	5,215	5,732
Property, plant and equipment, net	3,048	5,974	7,877	8,283	11,823
Total assets	10,628	23,355	30,716	33,738	41,551
Long-term debt, including current maturities, and capital leases	6,521	9,384	10,071	10,867	11,184
Total stockholders' equity	$(1,234)	$1,968	$4,446	$5,434	$11,695

(a) Excludes impairment losses and impairment losses on investments

(b) Includes goodwill impairment as described in Item 15 - Note 10, Goodwill and Other Intangibles, to the Consolidated Financial Statements

(c) Liquidity position is determined as disclosed in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, Liquidity Position. It excludes collateral funds deposited by counterparties of $33 million, $37 million and $2 million as of December 31, 2018, 2017 and 2016, 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

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

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions)				
Energy revenue	$2,677	$2,725	$3,243	$4,131	$4,215
Capacity revenue	670	618	642	781	690
Retail revenue	7,110	6,374	6,332	6,907	7,371
Mark-to-market for economic hedging activities	(209)	33	(566)	(138)	684
Contract amortization	—	(1)	(1)	(1)	1
Other revenues	287	235	313	202	313
Corporate/Eliminations	(1,057)	(910)	(1,048)	(1,040)	(1,887)
Total operating revenues[(a)]	$9,478	$9,074	$8,915	$10,842	$11,387

[(a)] Inter-segment sales and net derivative gains and losses included in operating revenues

Energy revenue consists of revenues received from third parties as well as from the Company's retail businesses, 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. These amounts are amortized into revenue over the term of the underlying contracts based on contracted volumes.
Other revenues 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 third party and 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. 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 include 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 Energy Inc., or NRG or the Company, operates, a discussion of regulation, weather, competition and other factors that affect the business, Transformation Plan update, and other significant events that are important to understanding the results of operations and financial condition;
- 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, 2018, 2017, and 2016, and also refer to Item 1 to this Form 10-K for more detailed discussion about the Company's business.

As further described in Note 3, Acquisitions, Discontinued Operations and Dispositions, the Company is treating the following businesses as discontinued operations, which have been recast to present in the corporate segment:

- South Central Portfolio
- NRG Yield, Inc. and its Renewables Platform
- Carlsbad
- GenOn

Executive Summary

NRG is an energy company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to consumers by producing, selling and delivering electricity and related products and services in major competitive power markets in the U.S. in a manner that delivers value to all of NRG's stakeholders. The Company sells energy, services, and innovative, sustainable products and services directly to retail customers under the names "NRG" and "Reliant" and other brand names owned by NRG supported by approximately 23,000[(a)] MW of generation as of December 31, 2018.

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 2018 and for the future medium term include:

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. 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 2018, average natural gas prices at Henry Hub was 1.0% lower than in 2017.

If long-term gas prices decrease, 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.

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.

(a) excluding discontinued operations and held for sale

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. An increase in supply cost volatility in the competitive retail markets may result in smaller companies choosing to exit the market, which may result in further consolidation in the competitive retail space. 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, 2018, 2017, and 2016. Power prices were higher for the year ended December 31, 2018 as compared to the same period in 2017 and 2016. ERCOT power prices were higher primarily due to the continued effect of lower reserve margins as a result of asset retirements in the region. Power prices in East region increased for the year ended December 31, 2018 as compared to the same period in 2017 and 2016 primarily driven by higher winter demand and higher natural gas prices in the fourth quarter of 2018.

	Average On-Peak Power Price ($/MWh)				
	Year Ended December 31			2018 vs 2017	2017 vs 2016
Region	2018	2017	2016	Change %	Change %
Texas [(a)]					
ERCOT - Houston[(a)]	$37.29	$33.95	$26.91	10 %	26 %
ERCOT - North[(a)]	36.26	25.86	24.53	40 %	5 %
East/West					
MISO - Louisiana Hub[(b)]	43.70	40.02	34.30	9 %	17 %
NY J/NYC[(b)]	47.19	38.34	35.29	23 %	9 %
NEPOOL[(b)]	49.96	37.18	35.05	34 %	6 %
COMED (PJM)[(b)]	34.60	32.46	32.11	7 %	1 %
PJM West Hub[(b)]	41.66	34.14	33.79	22 %	1 %
CAISO - SP15[(b)]	47.33	36.48	31.17	30 %	17 %

(a) Average on-peak power prices based on real time settlement prices as published by the respective ISOs
(b) Average on-peak power prices based on day ahead settlement prices as published by the respective ISOs

The following table summarizes average realized power prices for each region in which NRG operates for the years ended December 31, 2018, 2017, and 2016, which reflects the impact of settled hedges.

	Average Realized Power Price ($/MWh)				
	Year Ended December 31			2018 vs 2017	2017 vs 2016
Region	2018	2017	2016	Change %	Change %
Texas	$37.12	$33.45	$40.49	11 %	(17)%
East/West	43.70	46.48	47.14	(6)%	(1)%

The average realized power prices for December 31, 2018 as compared to the same period in 2017, increased in Texas as a result of higher power prices, and decreased in East/West as a result of the roll off of hedges. The average realized power prices for December 31, 2017 as compared to the same period in 2016 decreased in both Texas and East/West as a result of the roll off of hedges.

Clean Infrastructure Development — Policy mechanisms at the state and federal level including production and investment tax credits, cash grants, loan guarantees, accelerated depreciation tax benefits, RPS, and carbon trading plans, have supported and continue to support the development of renewable generation, demand-side and smart grid, and other clean infrastructure technologies. In addition, the costs associated with the development of clean infrastructure, such as wind and solar generating facilities, continues to decline. These factors continue to drive increases in the development of clean infrastructure in the markets where the Company participates, which may impact the ability of the Company's generating facilities to participate in those markets. According to ERCOT, Inc., more than 30% of 2018 energy consumption in the ERCOT market was generated from carbon-free resources with wind power contributing 19%. Certainly, subsidies and incentives have contributed to the increase in renewable power sources, but it is also true that customer awareness/preferences have shifted toward sustainable solutions. Alternatively, increased demand for sustainable energy products from both residential and commercial consumers creates opportunities for diversified product offerings in competitive retail markets.

Digitization and Customization — The electric industry is experiencing major technology changes in the way power is distributed and used by end-use customers. The electric grid is shifting from a centralized analog system, where power is generated from limited sources and flows in one direction, to a decentralized multidirectional system, where power can be generated from a number of distributed resources and stored or dispatched on an as-needed basis. In addition, consumers are seeking new ways to engage with their power providers. Technologies like smart thermostats, appliances and electric vehicles are giving individuals more choice and control over their electricity usage.

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 and 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.

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 23, Environmental Matters, to the Consolidated Financial Statements and Item 1— Business, Environmental Matters, section. Details of regulatory matters are presented in Item 15 — Note 22, Regulatory Matters, to the Consolidated Financial Statements and Item 1— Business, Regulatory Matters, section. Details of legal proceedings are presented in Item 15 — Note 21, 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.

Transformation Plan

NRG is well underway in executing its Transformation Plan. The Company expects to fully implement the Transformation Plan by the end of 2020 with a significant portion completed in 2018. The three-part, three-year plan is comprised of the following targets and the Company's achievements towards such targets are as follows:

Operations and Cost Excellence

Recurring cost savings and margin enhancement of $1,065 million, which consists of $590 million of cumulative cost savings, a $215 million net margin enhancement program, $50 million annual reduction in maintenance capital expenditures, and $210 million in permanent selling, general and administrative expense reduction associated with asset sales. The Company realized annual cost savings of $532 million and $32 million of margin enhancements during the year ended December 31, 2018 and is on track to realize $590 million of cost savings and $135 million of margin enhancements in 2019.

The Company expects to realize (i) $370 million of non-recurring working capital improvements through 2020 and (ii) approximately $290 million one-time costs to achieve. By December 31, 2018, NRG has realized $333 million of non-recurring working capital improvements and $194 million of one-time costs to achieve. The Company expects to incur approximately $95 million of one-time costs to achieve in 2019.

Portfolio Optimization

Targeted and completed $3.0 billion of asset sale cash proceeds received through February 28, 2019, as described below:

- In 2017, NRG executed asset sales of 322 MW for aggregate cash of $150 million, which includes sales to NRG Yield, Inc. and the sale of Minnesota wind projects to third parties
- On March 30, 2018, the Company completed the sale of 100% of its ownership interest in Buckthorn Solar to NRG Yield, Inc. for cash consideration of approximately $42 million
- On August 1, 2018, the Company completed the sale of 100% of its ownership interests in BETM to Diamond Energy Trading and Marketing, LLC for $70 million, excluding working capital adjustments. The sale also resulted in the release and return of approximately $119 million of letters of credit, $32 million of parent guarantees, and $4 million of net cash collateral to NRG
- On August 31, 2018, the Company completed the sale of its interest in NRG Yield, Inc. and its Renewables Platform to GIP, for approximately $1.348 billion in cash proceeds
- On November 1, 2018, the Company offered to Clearway Energy, Inc. its ownership interest in Agua Caliente Borrower 1, LLC, for approximately $120 million, which owns a 35% interest in AGua Caliente, a 290 MW utility scale solar project. The offer expired on January 31, 2019 with no action taken by Clearway Energy, Inc. As a result of this expiration, the Company has removed this asset from the target asset sale cash proceeds under the Transformation Plan.
- During the twelve months ended December 31, 2018, the Company completed the sale of various other assets for approximately $28 million
- On February 4, 2019, NRG sold the South Central portfolio, a 3,555 MW portfolio of generation assets, for cash consideration of $1 billion, excluding working capital and other adjustments
- On February 20, 2019, NRG completed the sale of Guam for cash consideration of approximately $8 million
- On February 27, 2019, NRG sold the Carlsbad project, a 528 MW natural gas-fired power plant, for cash consideration of $387 million, excluding working capital and other adjustments

Capital Structure and Allocation

As of December 31, 2018, the Company achieved the previously announced target of reducing consolidated corporate debt to 3.0x net debt / adjusted EBITDA[a] credit ratio on a pro forma basis that includes the South Central Portfolio sale proceeds. To achieve this ratio, the Company completed the following:

- Reduction of $9.2 billion in non-recourse debt related to the sale of NRG Yield, Inc. and the Renewable Platform, which includes the debt for Carlsbad Energy Center, as well as the impact of deconsolidation of Agua Caliente and Ivanpah
- The Company has completed its targeted $640 million of debt reduction through the redemption of $485 million of its outstanding 6.250% senior notes due 2022 and the Term Loan prepayment of $155 million. The annualized interest savings related to these activities to date totals $37 million

In 2018, the Company's board of directors authorized the Company to repurchase $1.5 billion of its common stock. As of February 28, 2019, the Company completed $1.5 billion of repurchases at an average price of $36.24 per share. In addition, the Company's board of directors authorized in February 2019 an additional $1 billion share repurchase program to be executed in 2019.

(a) adjusted EBITDA as defined per the Senior Credit Facility

Other Significant Events

The following additional significant events occurred during 2018:

XOOM Energy Acquisition

- On June 1, 2018, the Company completed the acquisition of XOOM Energy, LLC, an electricity and natural gas retailer operating in 19 states, Washington, D.C. and Canada for approximately $213 million in cash. See Note 3, Acquisitions, Discontinued Operations and Dispositions for further discussion on purchase price allocation. The acquisition increased NRG's retail portfolio by approximately 300,000 customers.

Agua Caliente and Ivanpah Deconsolidation

- During the third quarter of 2018, the Company, recognized a gain of $8 million on the deconsolidation and subsequent recognition of its 35% interest in Agua Caliente as an equity method investment, as discussed in more detail in Note 3 Acquisitions, Discontinued Operations and Dispositions

During the second quarter of 2018, the Company, recognized a loss of $22 million on the deconsolidation and subsequent recognition of its 54.6% interest in Ivanpah as an equity method investment, as discussed in more detail in Note 15, Investments Accounted for by the Equity Method and Variable Interest Entities.

Financing Activities

- On March 21, 2018, the Company repriced the 2023 Term Loan Facility, reducing the interest rate margin by 50 basis points to LIBOR plus 1.75% and reducing the LIBOR floor to 0.00%. As a result of the repricing, the Company expects approximately $47 million in interest savings over the remaining life of the loan.
- On May 24, 2018, the Company issued $575 million in aggregate principal amount at par of 2.75% convertible senior notes due 2048, as discussed in more detail in Note 11, Debt and Capital Leases.
- During the year ended December 31, 2018, the Company completed senior note repurchases of $1,061million in aggregate principal of its senior notes for $1,106 million, including accrued interest, as discussed in more detail in Note 11, Debt and Capital Leases.
- The annualized interest savings related to these activities to date totals $20 million

Consolidated Results of Operations for the years ended December 31, 2018 and 2017
The following table provides selected financial information for the Company:

(in millions except otherwise noted)	Year Ended December 31, 2018	2017	Change
Operating Revenues			
Energy revenue [a]	$1,548	$1,636	$(88)
Capacity revenue [a]	670	612	58
Retail revenue	7,105	6,378	727
Mark-to-market for economic hedging activities	(130)	252	(382)
Contract amortization	—	(1)	1
Other revenues [b]	285	197	88
Total operating revenues	9,478	9,074	404
Operating Costs and Expenses			
Cost of sales [b]	5,878	5,432	(446)
Mark-to-market for economic hedging activities	(144)	46	190
Contract and emissions credit amortization [c]	27	34	7
Operations and maintenance	1,083	1,097	14
Other cost of operations	264	277	13
Total cost of operations	7,108	6,886	(222)
Depreciation and amortization	421	596	175
Impairment losses	99	1,534	1,435
Selling, general and administrative	799	836	37
Reorganization costs	90	44	(46)
Development costs	11	22	11
Total operating costs and expenses	8,528	9,918	1,390
Other income - affiliate	—	87	(87)
Gain on sale of assets	32	16	16
Operating Income/(Loss)	982	(741)	1,723
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	9	(14)	23
Impairment losses on investments	(15)	(79)	64
Other income, net	18	51	(33)
Net loss on debt extinguishment	(44)	(49)	5
Interest expense	(483)	(557)	74
Total other expenses	(515)	(648)	133
Income/(Loss) from Continuing Operations Before Income Taxes	467	(1,389)	1,856
Income tax expense/(benefit)	7	(44)	51
Income/(Loss) from Continuing Operations	460	(1,345)	1,805
Loss from discontinued operations, net of income tax	(192)	(992)	800
Net Income/(Loss)	268	(2,337)	2,605
Less: Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	—	(184)	184
Net Income/(Loss) Attributable to NRG Energy, Inc.	$268	$(2,153)	$2,421
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$3.09	$3.11	(1)%

(a) Includes realized gains and losses from financially settled transactions
(b) Includes unrealized trading gains and losses
(c) Includes amortization of SO_2 and NO_x credits and excludes amortization of RGGI credits

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Economic Gross Margin

In addition to 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. Economic gross margin should be viewed as a supplement to and not a substitute for the Company's presentation of gross margin, which is the most directly comparable GAAP measure. Economic gross margin is not intended to represent gross margin. 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 and other revenue, less cost of fuels and other cost of sales.

Economic gross margin does not include mark-to-market gains or losses on economic hedging activities, contract amortization, emission credit amortization, or other operating costs.

The tables below present the composition and reconciliation of gross margin and economic gross margin which reflects the Company's current view of reporting segments for the years ended December 31, 2018 and 2017:

	Year Ended December 31, 2018					
		Generation				
(In millions except otherwise noted)	Retail	Texas	East/West/Other[a][b]	Subtotal	Corporate/Eliminations	Total
Energy revenue	$—	$1,585	$ 1,092	$2,677	$ (1,129)	$1,548
Capacity revenue	—	1	669	670	—	670
Retail revenue	7,110	—	—	—	(5)	7,105
Mark-to-market for economic hedging activities	(7)	(174)	(28)	(202)	79	(130)
Other revenue	—	84	203	287	(2)	285
Operating revenue	7,103	1,496	1,936	3,432	(1,057)	9,478
Cost of fuel	(23)	(734)	(557)	(1,291)	(4)	(1,318)
Other costs of sales[c]	(5,285)	(133)	(275)	(408)	1,133	(4,560)
Mark-to-market for economic hedging activities	260	2	(39)	(37)	(79)	144
Contract and emission credit amortization	—	(26)	(1)	(27)	—	(27)
Gross margin	$2,055	$605	$ 1,064	$1,669	$ (7)	$3,717
Less: Mark-to-market for economic hedging activities, net	253	(172)	(67)	(239)	—	14
Less: Contract and emission credit amortization, net	—	(26)	(1)	(27)	—	(27)
Economic gross margin	$1,802	$803	$ 1,132	$1,935	$ (7)	$3,730
Business Metrics						
MWh sold (thousands)		42,701	$ 24,988			
MWh generated (thousands)		38,214	$ 21,089			

(a) Includes International, Renewables, and Generation eliminations

(b) Includes Agua, BETM and Ivanpah which were sold or deconsolidated as of August, July and April 2018, respectively

(c) Includes purchased energy, capacity and emissions credits

	Year Ended December 31, 2017					
		Generation				
(In millions except otherwise noted)	Retail	Texas	East/West/Other[a]	Subtotal	Corporate/Eliminations	Total
Energy revenue	$—	$1,427	$ 1,298	$2,725	$ (1,089)	$1,636
Capacity revenue	—	22	596	618	(6)	612
Retail revenue	6,374	—	—	—	4	6,378
Mark-to-market for economic hedging activities	(4)	94	(57)	37	219	252
Contract amortization	(1)	—	—	—	—	(1)
Other revenue	—	35	200	235	(38)	197
Operating revenue	6,369	1,578	2,037	3,615	(910)	9,074
Cost of fuel	(13)	(732)	(542)	(1,274)	1	(1,286)
Other costs of sales[b]	(4,759)	(137)	(370)	(507)	1,120	(4,146)
Mark-to-market for economic hedging activities	181	(21)	13	(8)	(219)	(46)
Contract and emission credit amortization	—	(30)	(4)	(34)	—	(34)
Gross margin	$1,778	$658	$ 1,134	$1,792	$ (8)	$3,562
Less: Mark-to-market for economic hedging activities, net	177	73	(44)	29	—	206
Less: Contract and emission credit amortization, net	(1)	(30)	(4)	(34)	—	(35)
Economic gross margin	$1,602	$615	$ 1,182	$1,797	$ (8)	$3,391
Business Metrics						
MWh sold (thousands)		42,662	27,923			
MWh generated (thousands)		38,694	21,338			

(a) Includes International, Renewables, and Generation eliminations
(b) Includes purchased energy, capacity and emissions credits

The table below represents the weather metrics for 2018 and 2017:

	Years ended December 31,		Quarters ended December 31,		Quarters ended September 30,		Quarters ended June 30,		Quarters ended March 31,	
Weather Metrics	Texas	East/West/Other	Texas	East/West/Other	Texas	East/West/Other	Texas	East/West/Other	Texas	East/West/Other
2018										
CDDs[a]	3,130	1,213	228	74	1,657	856	1,101	265	144	18
HDDs[a]	1,874	3,393	815	1,214	1	26	90	425	968	1,728
2017										
CDDs	3,068	1,155	311	84	1,568	770	966	281	223	20
HDDs	1,270	3,198	665	1,157	1	33	32	380	572	1,628
10 year average										
CDDs	3,023	1,059	264	69	1,654	714	1,004	259	101	17
HDDs	1,728	3,459	695	1,214	3	40	56	429	974	1,776

(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.

Retail gross margin and economic gross margin

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

(In millions except otherwise noted)	Years ended December 31, 2018	2017
Retail revenue	$6,775	$6,104
Supply management revenue	174	187
Capacity revenues	161	83
Customer mark-to-market	(7)	(4)
Contract amortization	—	(1)
Operating revenue [(a)]	7,103	6,369
Cost of sales [(b)]	(5,308)	(4,772)
Mark-to-market for economic hedging activities	260	181
Gross margin	$2,055	$1,778
Less: Mark-to-market for economic hedging activities, net	253	177
Less: Contract and emission credit amortization	—	(1)
Economic gross margin	$1,802	$1,602
Business Metrics		
Mass electricity sales volume (GWh) - Texas	37,846	36,169
Mass electricity sales volume (GWh) - All other regions	7,968	6,221
C&I electricity sales volume (GWh) All regions [(b)]	21,176	20,400
Natural gas sales volumes (MDth)	11,253	3,212
Average Retail Mass customer count (in thousands)	3,063	2,862
Ending Retail Mass customer count (in thousands)	3,320	2,876

(a) Includes intercompany sales of $5 million and $5 million in 2018 and 2017, respectively, representing sales from Retail to the Texas region

(b) Includes intercompany purchases of $1,163 million and $1,090 million in 2018 and 2017, respectively

Retail gross margin increased $277 million and retail economic gross margin increased $200 million for the year ended December 31, 2018, compared to the same period in 2017, due to:

	(In millions)
Higher gross margin driven by margin enhancement initiatives enhancing customer product, retention, term and mix of $3.30 per MWh, or $208 million partially offset by higher supply costs due to increased power prices in ERCOT of $2.40 MWh, or $150 million.	$ 58
Higher gross margin due to higher volumes from net higher average customer counts primarily driven by XOOM acquisition in June 2018	60
Higher gross margin from the favorable impact of weather due to $44 million from an increase in load in 2018 of 1,893,000 MWh partially offset by an unfavorable impact of $14 million from selling back additional excess supply in 2018 as well as $16 million due to the impacts of Hurricane Harvey in 2017	46
Higher gross margin due to an increase in capacity revenues from the business solutions unit mainly due to approximately 1,600 additional MWs sold and margin enhancements from the sale of additional capacity of $11 million	36
Increase in economic gross margin	$ 200
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	76
Increase in contract and emission credit amortization	1
Increase in gross margin	$ 277

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Generation gross margin and economic gross margin
Generation gross margin decreased $123 million and generation economic gross margin increased $138 million, both of which include intercompany sales, during the year ended December 31, 2018, compared to the same period in 2017.

The tables below describe the change in Generation gross margin and generation economic gross margin:

Texas Region

	(In millions)
Higher gross margin due to a 11% increase in average realized prices	$ 153
Higher gross margin from sales of NOx emission credits	36
Higher gross margin from commercial optimization activities	5
Higher gross margin due to margin enhancement initiatives from reduced fuel supply costs	3
Lower gross margin driven by planned outages for both units at STP in 2018 as compared to a single unit planned outage in 2017	(9)
Lower gross margin due to an increase in tolling purchases in 2018 as a result of increased demand and the cancellation of the Greens Bayou RMR agreement in 2017	(9)
Other	9
Increase in economic gross margin	$ 188
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(245)
Increase in contract and emission credit amortization	4
Decrease in gross margin	$ (53)

East/West Region

	(In millions)
Lower gross margin primarily due to Ivanpah and Agua Caliente being deconsolidated in April 2018 and August 2018, respectively	$ (123)
Lower gross margin driven by a 26% decrease in realized capacity pricing in New York and expiration of the Long Beach capacity toll in July 2017	(51)
Lower gross margin mainly due to an 11% decrease in average realized prices, primarily at Midwest Generation	(42)
Lower gross margin due to decreased load contract volumes coupled with lower prices	(29)
Lower gross margin at Sunrise in 2018 due to planned major maintenance activities that extended into a forced outage.	(17)
Higher gross margin due to a 32% increase in PJM capacity prices and a 51% increase in NEISO capacity prices	132
Higher gross margin from commercial optimization activities	35
Higher gross margin due to 2017 lower cost of market adjustment for fuel inventory	31
Higher gross margin as a result of trading activity at BETM	8
Higher gross margin due to margin enhancement initiatives from reduced fuel supply costs	4
Other	2
Decrease in economic gross margin	$ (50)
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(23)
Increase in contract and emission credit amortization	3
Decrease in gross margin	$ (70)

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. Total net mark-to-market results decreased by $192 million during the year ended December 31, 2018, compared to the same period in 2017.

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

	Year Ended December 31, 2018				
		Generation			
	Retail	Texas	East/West/Other	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	$(2)	$32	$ (3)	$ (104)	$(77)
Net unrealized (losses)/gains on open positions related to economic hedges	(5)	(206)	(25)	183	(53)
Total mark-to-market (losses)/gains in operating revenues	$(7)	$(174)	$ (28)	$ 79	$(130)
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(81)	$(6)	$ (13)	$ 104	$4
Reversal of acquired gain positions related to economic hedges.	(10)	—	—	—	(10)
Net unrealized gains/(losses) on open positions related to economic hedges	351	8	(26)	(183)	150
Total mark-to-market gains/(losses) in operating costs and expenses	260	$2	$ (39)	$ (79)	$144

(a) Represents the elimination of the intercompany activity between Retail and Generation

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

	Year Ended December 31, 2017				
		Generation			
	Retail	Texas	East/West/Other	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	$(2)	$140	$ (72)	$ 64	$130
Net unrealized (losses)/gains on open positions related to economic hedges	(2)	(46)	15	155	122
Total mark-to-market (losses)/gains in operating revenues	$(4)	$94	$ (57)	$ 219	$252
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$(1)	$(17)	$ (1)	$ (64)	$(83)
Net unrealized gains/(losses) on open positions related to economic hedges	182	(4)	14	(155)	37
Total mark-to-market gains/(losses) in operating costs and expenses	$181	$(21)	$ 13	$ (219)	$(46)

(a) Represents the elimination of the intercompany activity between Retail and Generation

Mark-to-market results consist of unrealized gains and losses on contacts that are yet to be settled. The settlement of these transactions is reflected in the same revenue or cost caption as the items being hedged.

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The reversals of acquired gain or loss positions were valued based upon the forward prices on the acquisition date. For the year ended December 31, 2018 the $130 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, as well as a decrease in value of open positions as a result of losses on ERCOT heat rate positions due to heat rate expansion. The $144 million gain in operating costs and expenses from economic hedge positions was driven primarily by an increase in the value of open positions as a result of increases in ERCOT heat rate, partially offset by the reversal of acquired gain positions.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the years ended December 31, 2018 and 2017. The realized and unrealized financial and physical trading results are included in operating revenue. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Year ended December 31,	
(In millions)	2018	2017
Trading gains/(losses)		
Realized	$ 77	$ 43
Unrealized	17	(11)
Total trading gains	$ 94	$ 32

Operations and Maintenance Expense

	Retail	Generation Texas	Generation East/West/Other	Corporate	Eliminations	Total
Year Ended December 31, 2018	$ 209	$ 437	$ 440	$ 3	$ (6)	$ 1,083
Year Ended December 31, 2017	$ 224	$ 387	$ 458	$ 31	$ (3)	$ 1,097

Operations and maintenance expenses decreased by $14 million for the year ended December 31, 2018, compared to the same period in 2017, due to the following:

	(In millions)
Decrease in operations and maintenance due to cost efficiencies as a result of the Transformation Plan	$ (70)
Decrease in operations and maintenance due to the deconsolidation of Ivanpah and Agua Caliente in April 2018 and August 2018, respectively	(31)
Increase in major maintenance due to planned outages of $19 million in Texas and planned outages for both units at STP in 2018 as compared to a planned outage for a single unit in 2017 of $22 million	41
2018 payments in settlement of certain legal matters	13
Increase in technology and personnel costs for customer operations and retention related to margin enhancement	11
Increase in deactivation cost primarily at Dunkirk	8
Increase in costs due to the XOOM acquisition	7
Other	7
	$ (14)

(a) Approximately $162 million of additional cost savings were achieved in the year ended December 31, 2017, as compared to the year ended December 31, 2016, as the savings became permanent through the Transformation Plan

Other Cost of Operations

	Retail	Generation Texas	Generation East/West/Other	Total
	(In millions)			
Year Ended December 31, 2018	$ 109	$ 76	$ 79	$ 264
Year Ended December 31, 2017	$ 99	$ 81	$ 97	$ 277

Other cost of operations, decreased by $13 million for the year ended December 31, 2018, compared to the same period in 2017.

	(In millions)
Decrease due to lower in accretion expense in 2018 at Huntley as a result of a cost estimate increase in 2017	$ (8)
Decrease in property taxes as a result of the Transformation Plan	(4)
Other	(1)
	$ (13)

Depreciation and Amortization

	Retail	Generation	Corporate	Total
	(In millions)			
Year Ended December 31, 2018	$116	$ 272	$ 33	$421
Year Ended December 31, 2017	$110	$ 454	$ 32	$596

Depreciation and amortization expense decreased by $175 million for the year ended December 31, 2018, compared to the same period in 2017, primarily due to impairments of $1,534 million in 2017 and the deconsolidation of Ivanpah and Agua Caliente in 2018.

Impairment Losses

For the year ended December 31, 2018, the Company recorded impairment losses of $99 million related to various facilities as further described in Item 15 — Note 9, Asset Impairments, to the Consolidated Financial Statements.

In 2017, the Company recorded impairment losses of $1,534 million related to various facilities, as well as goodwill for its Texas reporting units, as further described in Item 15 — Note 9, Asset Impairments and Note 10, Goodwill and Other Intangibles, to the Consolidated Financial Statements.

Selling, General and Administrative Expenses

	Retail	Generation	Corporate	Total
	(In millions)			
Year Ended December 31, 2018	$538	$ 212	$ 49	$799
Year Ended December 31, 2017	$452	$ 215	$ 169	$836

Selling, general and administrative expenses decreased by $37 million for the year ended December 31, 2018 compared to the same period in 2017.

	(In millions)
Decrease in general and administrative expense from cost initiatives for the Transformation Plan[(a)]	$ (164)
Prior year fees associated with advisors engaged to assist the Company in its strategic review in 2017	(22)
Increase in selling and marketing expenses associated with costs incurred for margin enhancement initiatives	51
Increase in commission expense associated with selling initiatives	32
Increase in costs due to the XOOM acquisition	32
Increase in bad debt expense primarily from increased usage due to weather	18
Increase due to additional litigation in 2018	10
Other	6
	$ (37)

[(a)] Approximately $98 million of additional cost savings were achieved in the year ended December 31, 2017, as compared to the year ended December 31, 2016, as the savings became permanent through the Transformation Plan

Reorganization Costs
Reorganization costs, primarily related to severance and contract modifications, increased by $46 million for the year ended December 31, 2018, as compared to the same period in 2017 as the Company continued with the Transformation Plan announced in 2017.

Other Income - Affiliate
Other income - affiliate represents the services fees charged to GenOn for shared services under the Services Agreement through June 14, 2017, the date of deconsolidation of $87 million.

Gain on Sale of Assets
Gain on sale of assets for the year ended December 31, 2018, consists primarily of the gain on the sale of BETM and Canal 3, while the gain on sale of assets for the year ended December 31, 2017, represents a gain on the sale of land.

Impairment Losses on Investments
For the year ended December 31, 2018, the Company recorded other-than-temporary impairment losses of $15 million, compared to $79 million in other-than-temporary impairment losses recorded in the same period in 2017, as further described in Item 15 — Note 9, Asset Impairments, to the Consolidated Financial Statements.

Loss on Debt Extinguishment
A loss on debt extinguishment of $44 million was recorded for the year ended December 31, 2018, primarily driven by the redemption of Senior Notes, due 2022 at a price above par value.

A loss on debt extinguishment of $49 million was recorded for the year ended December 31, 2017, driven by the repurchase of Senior Notes at a price above par value and the write-off of the unamortized debt issuance costs related to the replacement of the 2018 Term Loan Facility with the new 2023 Term Loan Facility.

Income Tax Expense

For the year ended December 31, 2018, NRG recorded income tax expense of $7 million on pre-tax income of $467 million. For the same period in 2017, NRG recorded income tax benefit of $44 million on a pre-tax loss of $1,389 million. The effective tax rate was 1.5% and 3.2% for the years ended December 31, 2018 and 2017, respectively.

For the year ended December 31, 2018, NRG's overall effective tax rate was different than the federal statutory tax rate of 21% primarily due to a tax benefit for the change in valuation allowance, the generation of PTCs from various wind facilities, and establishment of the previously sequestered ATM credit receivable, partially offset by current state tax expense.

	Year Ended December 31,	
	2018	2017
	(In millions except as otherwise stated)	
Income/(Loss) from continuing operations before income taxes	$467	$(1,389)
Tax at federal statutory tax rate	98	(486)
State taxes	18	19
Foreign operations	—	2
Tax Act - corporate income tax rate change	—	665
Valuation allowance due to corporate income tax rate change	—	(660)
Valuation allowance - current period activities	(106)	455
Impact of non-taxable entity earnings	—	(5)
Book goodwill impairment	—	30
Permanent differences	7	—
Production tax credits	(7)	(8)
Recognition of uncertain tax benefits	1	(5)
Alternative minimum tax ("AMT") refundable credit	(4)	(64)
Other	—	13
Income tax expense/(benefit)	$7	$(44)
Effective income tax rate	1.5 %	3.2 %

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.

Income/(Loss) from Discontinued Operations, Net of Income Tax

	Year Ended December 31,		
(In millions)	2018	2017	Change
South Central	$66	87	$ (21)
Yield Renewables Platform & Carlsbad	(292)	(290)	(2)
Genon	34	(789)	823
Loss from discontinued operations, net of tax	$(192)	$(992)	$ 800

For the year ended December 31, 2018, NRG recorded a loss from discontinued operations, net of income tax of $192 million, a decrease of $800 million in losses from discontinued operations, net of income tax for the same period in 2017, as further described in Item 15 — Note 3 Acquisitions, Discontinued Operations and Dispositions .

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests was $0 million for the year ended December 31, 2018, compared to $184 million for the year ended December 31, 2017. For the years ended December 31, 2018, and 2017, 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 whole and in part by NRG Yield, Inc.'s share of income for the periods, respectively. As a result of the disposition of NRG Yield Inc. and its Renewables Platform, the Company did not have material actuals in 2018 nor does it anticipate material NCI in the future.

Consolidated Results of Operations for the years ended December 31, 2017 and 2016
The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Year Ended December 31, 2017	2016	Change
Operating Revenues			
Energy revenue [(a)]	$1,636	$2,269	$(633)
Capacity revenue [(a)]	612	637	(25)
Retail revenue	6,378	6,368	10
Mark-to-market for economic hedging activities	252	(636)	888
Contract amortization	(1)	(1)	—
Other revenues [(b)]	197	278	(81)
Total operating revenues	9,074	8,915	159
Operating Costs and Expenses			
Cost of sales [(a)]	5,432	5,562	130
Mark-to-market for economic hedging activities	46	(508)	(554)
Contract and emissions credit amortization [(c)]	34	40	6
Operations and maintenance	1,097	1,325	228
Other cost of operations	277	257	(20)
Total cost of operations	6,886	6,676	(210)
Depreciation and amortization	596	756	160
Impairment losses	1,534	483	(1,051)
Selling, general and administrative	836	1,032	196
Reorganization costs	44	—	(44)
Development costs	22	48	26
Total operating costs and expenses	9,918	8,995	(923)
Other income - affiliate	87	193	(106)
Gain/(loss) on sale of assets	16	(80)	96
Operating (Loss)/Income	(741)	33	(774)
Other Income/(Expense)			
Equity in losses of unconsolidated affiliates	(14)	(18)	4
Impairment losses on investments	(79)	(268)	189
Other income, net	51	47	4
Loss on debt extinguishment	(49)	(142)	93
Interest expense	(557)	(583)	26
Total other expense	(648)	(964)	316
Loss from Continuing Operations Before Income Taxes	(1,389)	(931)	(458)
Income tax (benefit)/expense	(44)	25	69
Net Loss from Continuing Operations	(1,345)	(956)	(389)
(Loss)/income from discontinued operations, net of tax	(992)	65	(1,057)
Net Loss	(2,337)	(891)	(1,446)
Less: Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	(184)	(117)	(67)
Net Loss Attributable to NRG Energy, Inc.	$(2,153)	$(774)	$(1,379)
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$3.11	$2.46	26 %

(a) Includes realized gains and losses from financially settled transactions
(b) Includes unrealized trading gains and losses
(c) Includes amortization of SO_2 and NO_x credits and excludes amortization of RGGI

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Gross Margin

The Company calculates gross margin in order to evaluate operating performance as operating revenues less cost of sales, which includes cost of fuel, other costs of sales, contract and emission credit amortization and mark-to-market for economic hedging activities.

Economic Gross Margin

In addition to 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. Economic gross margin should be viewed as a supplement to and not a substitute for the Company's presentation of gross margin, which is the most directly comparable GAAP measure. Economic gross margin is not intended to represent gross margin. 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 and other revenue, less cost of fuels and other cost of sales.

Economic gross margin does not include mark-to-market gains or losses on economic hedging activities, contract amortization, emission credit amortization, or other operating costs.

The tables below present the composition and reconciliation of gross margin and economic gross margin which reflects the Company's current view of reporting segments for the years ended December 31, 2017 and 2016:

	Year Ended December 31, 2017					
		Generation				
(In millions except otherwise noted)	Retail	Texas	East/West/Other[a]	Subtotal	Corporate/Eliminations	Total
Energy revenue	$—	$1,427	$ 1,298	$2,725	$ (1,089)	$1,636
Capacity revenue	—	22	596	618	(6)	612
Retail revenue	6,374	—	—	—	4	6,378
Mark-to-market for economic hedging activities	(4)	94	(57)	37	219	252
Contract amortization	(1)	—	—	—	—	(1)
Other revenue	—	35	200	235	(38)	197
Operating revenue	6,369	1,578	2,037	3,615	(910)	9,074
Cost of fuel	(13)	(732)	(542)	(1,274)	1	(1,286)
Other costs of sales[b]	(4,759)	(137)	(370)	(507)	1,120	(4,146)
Mark-to-market for economic hedging activities	181	(21)	13	(8)	(219)	(46)
Contract and emission credit amortization	—	(30)	(4)	(34)	—	(34)
Gross margin	$1,778	$658	$ 1,134	$1,792	$ (8)	$3,562
Less: Mark-to-market for economic hedging activities, net	177	73	(44)	29	—	206
Less: Contract and emission credit amortization, net	(1)	(30)	(4)	(34)	—	(35)
Economic gross margin	$1,602	$615	$ 1,182	$1,797	$ (8)	$3,391
Business Metrics						
MWh sold (thousands)		42,662	27,923			
MWh generated (thousands)		38,694	21,338			

(a) Includes International, Renewables, and Generation eliminations

(b) Includes purchased energy, capacity and emissions credits

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	Year Ended December 31, 2016					
		Generation				
(In millions except otherwise noted)	Retail	Texas	East/West/Other[a]	Subtotal	Corporate/Eliminations	Total
Energy revenue	$—	$1,705	$ 1,538	$3,243	$ (974)	$2,269
Capacity revenue	—	18	624	642	(5)	637
Retail revenue	6,332	—	—	—	36	6,368
Mark-to-market for economic hedging activities	(1)	(543)	(22)	(565)	(70)	(636)
Contract amortization	(1)	—	—	—	—	(1)
Other revenue	—	48	265	313	(35)	278
Operating revenue	6,330	1,228	2,405	3,633	(1,048)	8,915
Cost of fuel	(8)	(704)	(566)	(1,270)	—	(1,278)
Other costs of sales[b]	(4,675)	(147)	(463)	(610)	1,001	(4,284)
Mark-to-market for economic hedging activities	365	67	6	73	70	508
Contract and emission credit amortization	(6)	(29)	(5)	(34)	—	(40)
Gross margin	$2,006	$415	$ 1,377	$1,792	$ 23	$3,821
Less: Mark-to-market for economic hedging activities, net	364	(476)	(16)	(492)	—	(128)
Less: Contract and emission credit amortization, net	(7)	(29)	(5)	(34)	—	(41)
Economic gross margin	$1,649	$920	$ 1,398	$2,318	$ 23	$3,990
Business Metrics						
MWh sold (thousands)		42,108	32,625			
MWh generated (thousands)		37,676	23,748			

(a) Includes International, Renewables, and Generation eliminations

(b) Includes purchased energy, capacity and emissions credits

The table below represents the weather metrics for 2017 and 2016:

	Years ended December 31,		Quarter ended December 31,		Quarter ended September 30,		Quarter ended June 30,		Quarter ended March 31,	
Weather Metrics	Texas	East/West	Texas	East/West	Texas	East/West	Texas	East/West	Texas	East/West
2017										
CDDs[a]	3,068	1,155	311	84	1,568	770	966	281	223	20
HDDs[a]	1,270	3,198	665	1,157	1	33	32	380	572	1,628
2016										
CDDs	3,030	1,169	382	71	1,675	806	892	273	82	19
HDDs	1,422	3,190	498	1,145	—	23	47	410	878	1,612
10 year average										
CDDs	2,897	1,043	266	67	1,650	705	989	254	88	17
HDDs	1,928	3,504	691	1,227	5	40	64	438	1,025	1,799

(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

Retail gross margin and economic gross margin

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

	Years ended December 31,	
(In millions except otherwise noted)	2017	2016
Retail revenue	$6,104	$6,096
Supply management revenue	187	154
Capacity revenues	83	82
Customer mark-to-market	(4)	(1)
Contract amortization	(1)	(1)
Operating revenue [a]	6,369	6,330
Cost of sales [b]	(4,772)	(4,683)
Mark-to-market for economic hedging activities	181	365
Contract amortization	—	(6)
Gross margin	$1,778	$2,006
Less: Mark-to-market for economic hedging activities, net	177	364
Less: Contract and emission credit amortization	(1)	(7)
Economic gross margin	$1,602	$1,649
Business Metrics		
Mass electricity sales volume (GWh) - Texas	36,169	35,102
Mass electricity sales volume (GWh) - All other regions	6,221	6,764
C&I electricity sales volume (GWh) All regions	20,400	18,906
Natural gas sales volumes (MDth)	3,212	2,166
Average Retail Mass customer count (in thousands)	2,862	2,778
Ending Retail Mass customer count (in thousands)	2,876	2,818

(a) Includes intercompany sales of $5 million and $4 million in 2017 and 2016, respectively, representing sales from Retail to the Texas region

(b) Includes intercompany purchases of $1,090 million and $993 million in 2017 and 2016, respectively

Retail gross margin decreased $227 million and retail economic gross margin decreased $47 million for the year ended December 31, 2017, compared to the same period in 2016, due to:

	(In millions)
Lower gross margin due to lower rates to customers driven by customer product, term and mix of $103 million or approximately $1.60 per MWh, partially offset by lower supply cost of $28 million or approximately $0.50 per MWh driven by a decrease in supply costs	$ (75)
Lower gross margin related to the impact of Hurricane Harvey in 2017, driven by a reduction in load of 200,000 MWh resulting in an impact of $9 million and the unfavorable impact of selling back excess supply along with $7 million of customer relief	(16)
Lower gross margin due to milder weather conditions in 2017 as compared to 2016 resulting in a reduction in load of 350,000 MWh	(11)
Higher gross margin driven by higher average customer counts of 85,000 along with higher average usage due to customer mix	55
Decrease in economic gross margin	$ (47)
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(186)
Increase in contract and emission credit amortization	6
Decrease in gross margin	$ (227)

Generation gross margin and economic gross margin

Generation gross margin was flat and generation economic gross margin decreased $521 million, both of which include intercompany sales, during the year ended December 31, 2017, compared to the same period in 2016.

The tables below describe the change in generation gross margin and generation economic gross margin:

Texas Region

	(In millions)		
Lower gross margin due to a 14% decrease in average realized prices due to lower hedged power prices	$	(352	)
Lower gross margin due to lower gas generation driven by the current mothball status of Gregory in Texas	(17		)
Higher gross margin due to a 17% increase in coal generation driven by the timing of planned and unplanned outages	55		
Higher gross margin due to a decrease in tolling prices in 2017 offset by the cancellation of the Greens Bayou RMR agreement in 2017	5		
Other	4		
Decrease in economic gross margin	$	(305	)
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	549		
Decrease in contract and emission credit amortization	(1		)
Increase in gross margin	$	243	

East/West Region

	(In millions)	
Lower gross margin from commercial optimization activities	$ (63	)
Lower gross margin due to a decrease in generation driven by lower economic generation due to milder weather conditions and the Will County outage partially offset by increased generation at Cottonwood	(43	)
Lower gross margin due to a lower cost of market adjustment for fuel oil inventory	(33	)
Lower gross margin due to lower load contracted prices coupled with slightly lower volumes	(28	)
Lower gross margin by BETM due to higher gains in 2016 on over the counter strategies, offset in small part by higher gains in 2017 congestion strategies	(20	)
Lower gross margin due to lower capacity bi-lateral margins in 2017	(11	)
Lower gross margins due to the sale of certain renewable assets in 2017	(10	)
Lower gross margin at Agua driven by lower sales volumes resulting from weather and outages in 2017	(5	)
Lower gross margins due to higher business interruption proceeds from Cottonwood in 2016 offset by Ivanpah proceeds in 2017	(4	)
Other	1	
Decrease in economic gross margin	$ (216	)
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(28	)

Increase in contract and emission credit amortization	1
Decrease in gross margin	$ (243)

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. Total net mark-to-market results increased by $334 million in the year ended December 31, 2017, compared to the same period in 2016.

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

	Year Ended December 31, 2017				
		Generation			
	Retail	Texas	East/West/Other	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	$(2)	$140	$(72)	$64	$130
Net unrealized (losses)/gains on open positions related to economic hedges	(2)	(46)	15	155	122
Total mark-to-market (losses)/gains in operating revenues	$(4)	$94	$(57)	$219	$252
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$(1)	$(17)	$(1)	$(64)	$(83)
Net unrealized gains/(losses) on open positions related to economic hedges	182	(4)	14	(155)	37
Total mark-to-market gains/(losses) in operating costs and expenses	$181	$(21)	$13	$(219)	$(46)

(a) Represents the elimination of the intercompany activity between Retail and Generation

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

	Year Ended December 31, 2016				
		Generation			
	Retail	Texas	East/West/Other	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	$(3)	$(390)	$(87)	$33	$(447)
Net unrealized gains/(losses) on open positions related to economic hedges	2	(153)	65	(103)	(189)
Total mark-to-market losses in operating revenues	$(1)	$(543)	$(22)	$(70)	$(636)
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$305	$27	$20	$(33)	$319
Reversal of acquired gain positions related to economic hedges.	—	—	(12)	—	(12)
Net unrealized gains/(losses) on open positions related to economic hedges	60	40	(2)	103	201
Total mark-to-market gains in operating costs and expenses	$365	$67	$6	$70	$508

(a) Represents the elimination of the intercompany activity between Retail and Generation

Mark-to-market results consist of unrealized gains and losses on contracts that are not yet settled. The settlement of these transactions is reflected in the same revenue or cost caption as the items being hedged.

The reversals of acquired gain or loss positions were valued based upon the forward prices on the acquisition date.
For the year ended December 31, 2017, the $252 million gain in operating revenues from economic hedge positions was driven primarily by the reversal of previously recognized unrealized losses on contracts that settled during the period, as well as an increase in value of open positions as a result of decreases in gas prices. The $46 million loss in operating costs and expenses from economic hedge positions was driven primarily by the reversal of previously recognized unrealized gains on contracts that settled during the period, partially offset by an increase in the value of open positions as a result of increases in ERCOT heat rate.
In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the years ended December 31, 2017 and 2016. The realized and unrealized financial and physical trading results are included in operating revenues. The Company's trading activities are subject to limits within the Company's Risk Management Policy.

	Year Ended December 31,	
	2017	2016
	(In millions)	
Trading gains/(losses)		
Realized	$ 43	$ 71
Unrealized	(11)	28
Total trading gains	$ 32	$ 99

Operations and Maintenance Expense

	Retail	Generation Texas	East/West/Other	Corporate	Eliminations	Total
		(In millions)				
Year Ended December 31, 2017	$ 224	$ 387	$ 458	$ 31	$ (3)	$ 1,097
Year Ended December 31, 2016	$ 247	$ 434	$ 605	$ 43	$ (4)	$ 1,325

Operations and maintenance expenses decreased by $228 million for the year ended December 31, 2017, compared to the same period in 2016, due to the following:

	(In millions)
Decrease in operation and maintenance expenses due to major maintenance activities and environmental control work in the East offset by higher variable operating costs	$ (100)
Decrease in operations and maintenance expenses due to timing of planned outages in Texas	(32)
Decrease in Retail operations and maintenance expenses due to reduced headcount	(22)
Decrease in operations and maintenance expenses due to the gain on sale of Jewett Mine dragline in 2017	(18)
Decrease in operations and maintenance expense due to reductions at Residential Solar	(16)
Decrease in operations and maintenance expenses due to gain on sale of fixed assets in the East	(15)
Decrease in operation and maintenance expenses due to a reduction in headcount related to the sale of the engine services business	(10)
Decrease in operations and maintenance expenses due to the sale of wind assets in 2016 and early 2017	(10)
Other	(5)
	$ (228)

Other cost of operations

	Retail	Generation Texas	East/West/Other	Corporate	Total
		(In millions)			
Year Ended December 31, 2017	$ 99	$ 81	$ 97	$ —	$ 277
Year Ended December 31, 2016	$ 93	$ 75	$ 88	$ 1	$ 257

Other cost of operations, comprised of asset retirement expense, insurance expense and property tax expense, increased by $20 million for the year ended December 31, 2017, compared to the same period in 2016.

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Depreciation and Amortization

	Retail	Generation	Corporate	Total
	(In millions)			
Year Ended December 31, 2017	$110	$ 454	$ 32	$596
Year Ended December 31, 2016	$114	$ 593	$ 49	$756

Depreciation and amortization expense decreased by $160 million for the year ended December 31, 2017, compared to the same period in 2016, primarily due to due to the Jewett Mine being fully depreciated in December 2016 as well as impairments in 2016.

Impairment Losses

In 2017, the Company recorded impairment losses of $1,534 million related to various facilities, as well as goodwill for its Texas reporting unit, as further described in Item 15 — Note 9, Asset Impairments and Note 10, Goodwill and Other Intangibles, to the Consolidated Financial Statements.

In 2016, the Company recorded impairment losses of $483 million related to various facilities, as well as goodwill for its Texas and Home Solar reporting units, as further described in Item 15 - Note 9, Asset Impairments to the Consolidated Financial Statements.

Selling, General and Administrative Expenses

	Retail	Generation	Corporate	Total
	(In millions)			
Year Ended December 31, 2017	$452	$ 215	$ 169	$836
Year Ended December 31, 2016	$498	$ 279	$ 255	$1,032

Selling, general and administrative expenses decreased by $196 million[(a)] for the year ended December 31, 2017 compared to the same period in 2016, primarily due to a reduction in personnel costs and selling and marketing activities as the Company continues to focus on cost management.

(a) Approximately $98 million of additional cost savings were achieved in the year ended December 31, 2017, as compared to the year ended December 31, 2016, as the savings became permanent through the Transformation Plan

Development Costs

Development costs decreased by $26 million for the year ended December 31, 2017, compared to the same period in 2016, due to the strategic decision for a more focused development program primarily related to Renewables and the sale of EVgo in 2016.

Gain/(Loss) on Sale of Assets

Gain on sale of assets for the year ended December 31, 2017, represents a gain on the sale of land. The loss on sale of assets for the year ended December 31, 2016 is primarily due to the loss on sale of the Company's majority interest in its EVgo business to Vision Ridge Partners, which resulted in a loss on sale as described in Item 15 — Note 3, Acquisitions, Discontinued Operations and Dispositions, to the Consolidated Financial Statements.

Impairment Losses on Investments

For the year ended December 31, 2017, the Company recorded impairment losses of $79 million, which is primarily due to impairments on the Company's interests in Petra Nova Parish Holdings as well as as impairments on other investments as further described in Item 15 — Note 9, Asset Impairments, to the Consolidated Financial Statements.

For the year ended December 31, 2016, the Company recorded impairment losses on certain of its cost and equity method investments of $270 million, as further described in Item 15 — Note 9, Asset Impairments, to the Consolidated Financial Statements.

Loss on Debt Extinguishment

A loss on debt extinguishment of $49 million was recorded for the year ended December 31, 2017, primarily driven by the repurchase of Senior Notes at a price above par value and the write-off of the unamortized debt issuance costs related to the replacement of the 2018 Term Loan Facility with the new 2023 Term Loan Facility.

A loss on debt extinguishment of $142 million was recorded for the year ended December 31, 2016, primarily driven by the repurchase of NRG senior notes at a price above par value and the write-off of the unamortized debt issuance costs related to the replacement of the 2018 Term Loan Facility with the new 2023 Term Loan Facility.

Interest Expense

NRG's interest expense decreased by $26 million for the year ended December 31, 2017, compared to the same period in 2016, primarily due to lower debt balances resulting in less interest.

Income Tax Expense

For the year ended December 31, 2017, NRG recorded an income tax benefit of $44 million on a pre-tax loss of $1,389 million. For the same period in 2016, NRG recorded an income tax expense of $25 million on pre-tax loss of $931 million. The effective tax rate was 3.2% and (2.7)% for the years ended December 31, 2017 and 2016, respectively.

For the year ended December 31, 2017, NRG's overall effective tax rate was different than the federal statutory tax rate of 35% primarily due to tax expense recorded from the revaluation of the existing net deferred tax asset and state taxes, partially offset by the change in valuation allowance, establishing the AMT credit receivable and the generation of PTCs from various wind facilities. The tax expense recorded for revaluation of the net deferred tax asset is required to reflect the reduction in the corporate income tax rate from 35% to 21% in accordance with the Tax Act.

	Year Ended December 31,	
	2017	2016
	(In millions except as otherwise stated)	
Loss from continuing operations before income taxes	$(1,389)	$(931)
Tax at federal statutory tax rate	(486)	(326)
State taxes	19	—
Foreign operations	2	10
Tax Act - corporate income tax rate change	665	—
Valuation allowance due to corporate income tax rate change	(660)	—
Valuation allowance - current period activities	455	382
Impact of non-taxable entity earnings	(5)	22
Book goodwill impairment	30	—
Net interest accrued on uncertain tax positions	—	1
Production tax credits	(8)	(7)
Recognition of uncertain tax benefits	(5)	2
Impact of changes is in effective state	—	(59)
AMT refundable credit	(64)	—
Other	13	—
Income tax (benefit)/expense	$(44)	$25
Effective income tax rate	3.2%	(2.7)%

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

(Loss)/Income from Discontinued Operations, Net of Income Tax

	Year Ended December 31,		
(In millions)	2017	2016	Change
South Central	$87	$72	$15
Yield Renewables Platform & Carlsbad	(290)	(99)	(191)
Genon	(789)	92	(881)
(Loss)/income from discontinued operations, net of tax	$(992)	$65	$(1,057)

For the year ended December 31, 2017, NRG recorded a loss from discontinued operations, net of income tax of $992 million, an increase of $1.1 billion in losses from discontinued operations, net of income tax for the same period in 2016, as further described in Item 15 — Note 3 Acquisitions, Discontinued Operations and Dispositions.

(Loss)/Income from Discontinued Operations, Net of Income Tax

For the year ended December 31, 2017, NRG recorded loss from discontinued operations, net of income tax of $992 million, of which $359 million was related to operations of GenOn, Carlsbad, NRG Yield Inc. and its Renewables Platform, and the South Central Portfolio and $633 million was related to the loss, fees and other expenses associated with the dispositions.

For the year ended December 31, 2016, NRG recorded income from discontinued operations, net of income tax of $65 million which was related to operations of GenOn, NRG Yield Inc. and its Renewables Platform, and the South Central Portfolio.

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests was $184 million for the year ended December 31, 2017, compared to $117 million for the year ended December 31, 2016. For the years ended December 31, 2017 and 2016, 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.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2018 and 2017, NRG's liquidity, excluding collateral funds deposited by counterparties, was approximately $2.0 billion and $2.8 billion, respectively, comprised of the following:

	As of December 31,	
	2018	2017
	(In millions)	
Cash and cash equivalents:	$563	$770
Restricted cash - operating	6	85
Restricted cash - reserves [(a)]	11	194
Total	580	1,049
Total credit facility availability	1,397	1,711
Total liquidity, excluding collateral funds deposited by counterparties	$1,977	$2,760

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

For the year ended December 31, 2018, total liquidity, excluding collateral funds deposited by counterparties, decreased by $783 million. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading Cash Flow Discussion. Cash and cash equivalents at December 31, 2018 were predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

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

Credit Ratings

On December 6, 2018, Moody's upgraded the NRG corporate family rating to Ba2 and senior unsecured rating to Ba3 with positive outlook. The rating agency also affirmed the company's senior secured rating at Baa3.

On September 10, 2018, S&P upgraded its issuer credit rating to BB with a stable outlook. At the same time they raised the issue-level secured and unsecured ratings to BBB and BB respectively.

The following table summarizes the Company's current credit ratings:

	S&P	Moody's
NRG Energy, Inc.	BB Stable	Ba2 Positive
6.25% Senior Notes, due 2024	BB	Ba3
7.25% Senior Notes, due 2026	BB	Ba3
6.625% Senior Notes, due 2027	BB	Ba3
5.75% Senior Notes, due 2028	BB	Ba3
Term Loan Facility, due 2023	BBB-	Baa3

Sources of Liquidity

The principal sources of liquidity for NRG's operating and capital expenditures are expected to be derived from cash on hand, cash flows from operations, cash proceeds from future sales of assets and financing arrangements. As described in Item 15 — Note 11, Debt and Capital Leases, to the Consolidated Financial Statements, the Company's financing arrangements consist mainly of the Senior Credit Facility, the Senior Notes, and project-related financings.

Asset Sale Proceeds

The table below represents the approximate purchase price received from sale transactions and related financings completed by the Company during the year ended December 31, 2018.

Sales	Cash Proceeds (in millions)
NRG Yield, Inc and Renewables Platform	$ 1,348
Buckthorn Solar [(a)]	42
UPMC Thermal Project [(a)]	84
BETM	70
Canal 3[(b)]	167
Other Sales	12
Completed sales transactions as of December 31, 2018	$ 1,723

(a) Sale of assets to NRG Yield, Inc., prior to discontinued operations

(b) In addition to cash proceeds from sale, amount includes $151 million related to a financing arrangement prior to the sale

The table below represents the cash proceeds received from sales transactions, excluding working capital or other adjustments, completed by the Company by February 28, 2019.

Expected Sales	Close Date	Cash Proceeds (in millions)
South Central Portfolio	February 4, 2019	$ 1,000
Carlsbad	February 27, 2019	387
Cash proceeds from sales transactions in 2019		$ 1,387

2048 Convertible Senior Notes Issuance

On May 24, 2018, the Company issued $575 million in aggregate principal amount at par of 2.75% convertible senior notes due 2048.

First Lien Structure

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

The Company's first lien counterparties may have a claim on its assets to the extent market prices exceed the hedged prices. As of December 31, 2018, all hedges under the first liens were out-of-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MW hedged against the Company's coal and nuclear assets and as a percentage relative to the Company's coal and nuclear capacity under the first lien structure as of December 31, 2018:

Equivalent Net Sales Secured by First Lien Structure [(a)]	2019	2020	2021	2022
In MW	596	831	712	743
As a percentage of total net coal and nuclear capacity [(b)]	13 %	18 %	16 %	16 %

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

(b) Net coal and nuclear capacity represents 80% of the Company's total coal and nuclear assets eligible under the first lien, which excludes coal assets acquired in the Midwest Generation acquisition and NRG's assets that have project-level financing

Uses of Liquidity

The Company's requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (i) commercial operations activities; (ii) debt service obligations, as described more fully in Item 15 — Note 11, Debt and Capital Leases, to the Consolidated Financial Statements; (iii) capital expenditures, including repowering development, and environmental; and (iv) allocations in connection with acquisition opportunities, debt repayments, return of capital and dividend payments to stockholders, as described in Item 15 — Note 14, Capital Structure, to the Consolidated Financial Statements.

Commercial Operations

The Company's commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) margin and collateral required to participate in physical markets and commodity exchanges; (iii) timing of disbursements and receipts (e.g. buying fuel before receiving energy revenues); (iv) initial collateral for large structured transactions; and (v) collateral for project development. As of December 31, 2018, commercial operations had total cash collateral outstanding of $287 million and $793 million outstanding in letters of credit to third parties primarily to support its commercial activities for both wholesale and retail transactions. As of December 31, 2018, total collateral held from counterparties was $33 million in cash and $108 million of letters of credit.

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

2023 Term Loan Facility

In accordance with the terms of the Credit Agreement, on October 5, 2018, the Company initiated an asset sale offer to purchase a portion of its Term Loan following the sale of NRG Yield and the Renewables Platform. The offer expired on November 5, 2018, and $260 million of Term Loan holders accepted the offer. As a result, the Company prepaid $155 million of Term Loans as part of its de-leveraging plan, as well as established an incremental first lien secured loan term facility under the Senior Credit Facility in the aggregate principal amount of $105 million on the same terms and conditions to stay within its debt reduction target.

In accordance with the terms of the credit agreement, upon the consummation of the sales of the South Central Portfolio and Carlsbad, the Company will initiate asset sale offers to purchase a portion of its Term Loan. The Company has one year from the date of each sale to initiate the offer.

Senior Note Repurchases in 2018

During the year ended December 31, 2018, the Company redeemed $1.1 billion in aggregate principal of its Senior Notes for $1.1 billion, which included accrued interest of $14 million. In connection with the redemptions, a $38 million loss on debt extinguishment was recorded in 2018, which included the write-off of previously deferred financing costs of $7 million.

In millions, except percentages	Principal Repurchased	Cash Paid (a)	Average Early Redemption Percentage
5.750% senior notes due 2028	$ 29	$ 30	99.24 %
6.250% senior notes due 2022	14	15	103.25 %
Total at June 30, 2018	$ 43	$ 45	
6.250% senior notes due 2022	493	512	103.13 %
5.750% senior notes due 2028	20	20	99.13 %
6.625% senior notes due 2027	20	21	103.06 %
Total at September 30, 2018	$ 576	$ 598	
6.250% senior notes due 2022	485	508	103.13 %
Total at December 31, 2018	$ 1,061	$ 1,106	

(a) Includes accrued interest of $14 million

Senior Note Redemptions in 2017

During the year ended December 31, 2017, the Company redeemed $1.5 billion in aggregate principal of its Senior Notes for $1.5 billion, which included accrued interest of $29 million. In connection with the redemptions, a $49 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $7 million.

Amount in millions, except percentages	Principal Repurchased	Cash Paid (a)	Average Early Redemption Percentage
7.625% senior notes due 2018	$ 398	$ 411	101.42 %
7.875% senior notes due 2021	206	218	102.63 %
6.625% senior notes due 2023	869	915	103.57 %
Total	$ 1,473	$ 1,544	

(a) Includes accrued interest of $29 million

Debt Service Obligations

Principal payments on debt and capital leases as of December 31, 2018 are due in the following periods:

Description	2019	2020	2021	2022	2023	Thereafter	Total
	(In millions)						
Recourse Debt:							
Senior notes, due 2024	$—	$—	$—	$—	$—	$ 733	$733
Senior notes, due 2026	—	—	—	—	—	1,000	1,000
Senior notes, due 2027	—	—	—	—	—	1,230	1,230
Senior notes, due 2028	—	—	—	—	—	821	821
Convertible Senior Notes, due 2048	—	—	—	—	—	575	575
Term loan facility, due 2023	17	18	17	17	1,629	—	1,698
Tax-exempt bonds	—	—	—	—	—	466	466
Subtotal Recourse Debt	17	18	17	17	1,629	4,825	6,523
Non-Recourse Debt:							
Agua Caliente Borrower 1, due 2038	3	3	3	3	2	72	86
Midwest Generation, due 2019	48	—	—	—	—	—	48
Other	6	5	6	5	4	8	34
Subtotal Non-Recourse Debt	57	8	9	8	6	80	168
Subtotal long-term debt	74	26	26	25	1,635	4,905	6,691
Capital Leases:							
Capital leases	—	—	1	—	—	—	1
Subtotal Capital Leases	—	—	1	—	—	—	1
Total Debt and Capital Leases	$74	$ 26	$ 27	$ 25	$1,635	$ 4,905	$6,692

In addition to the debt and capital leases shown in the above table, NRG had issued $1.0 billion of letters of credit under the Company's $2.4 billion Revolving Credit Facility as of December 31, 2018.

Capital Expenditures

The following table and descriptions summarize the Company's capital expenditures for maintenance, environmental, and growth investments, for the year ended December 31, 2018, and the estimated capital expenditure and growth investments forecast for 2019.

	Maintenance	Environmental	Growth Investments	Total
	(In millions)			
Retail	$19	$ —	$ 71	$90
Generation				
Texas	77	—	—	77
East/West/Other [(a)]	54	1	135	190
Corporate	9	—	22	31
Total cash capital expenditures for the year ended December 31, 2018	159	1	228	388
Funding from debt financing, net of fees	—	—	(118)	(118)
XOOM acquisition and integration	—	—	208	208
Other investments[(b)]	—	—	176	176
Total capital expenditures and investments, net of financings	$159	$ 1	$ 494	$654
Estimated capital expenditures for 2019	$155	$ 3	$ 65	$223

(a) Includes International, Renewables and Cottonwood

(b) Other investments include restricted cash activity and acquisitions

- Growth Investments capital expenditures — For the year ended December 31, 2018, the Company's growth investment capital expenditures included $134 million for repowering Canal 3, and $94 million for the Company's other growth projects.

Environmental Capital Expenditures Estimate

NRG estimates that environmental capital expenditures from 2019 through 2023 required to comply with environmental laws will be approximately $35 million. These costs are primarily associated with the cost of adding NO_x controls in Connecticut.

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

Units	State	SO_2 Control Equipment	Install Date	NO_x Control Equipment	Install Date	Mercury Control Equipment	Install Date	Particulate Control Equipment	Install Date
Indian River 4	DE	CDS	2011	LNBOFA/SCR	1999/2011	ACI/CDS/FF	2008/2011	ESP/FF	1980/2011
Joliet 6, 7, 8	IL	Gas Conversion	2016	OFA	2016	Gas Conversion	2016	Gas Conversion	2016
Limestone 1-2	TX	FGD	1985-86	LNBOFA	2002/2022	ACI	2015	ESP	1985-1986
Powerton 5	IL	DSI	2016	OFA/SNCR	2003/2012	ACI	2009	ESP/upgrade	1973/2016
Powerton 6	IL	DSI	2014	OFA/SNCR	2002/2012	ACI	2009	ESP/upgrade	1976/2014
W.A. Parish 5, 6, 7	TX	FF co-benefit	1988	SCR	2004	ACI	2015	FF	1988
W.A. Parish 8	TX	FGD	1982	SCR	2004	ACI	2015	FF	1988
Waukegan 7	IL	DSI	2014	LNBOFA	2002	ACI	2008	ESP/upgrade	1958/2002, 2014
Waukegan 8	IL	DSI	2015	LNBOFA	1999	ACI	2008	ESP/upgrade	1962/1999, 2015
Will County 4	IL	DSI	2017	LNBOFA/SNCR	1999,2001/ 2012	ACI	2009	ESP/upgrade	1963,72/ 2000

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

FF- Fabric Filter
LNBOFA - Low NO_x Burner with Overfire Air
OFA - Overfire Air
SCR - Selective Catalytic Reduction
SNCR - Selective Non-Catalytic Reduction

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

	Texas	East/West	Total
	(In millions)		
2019	$1	$ 2	$ 3
2020	8	5	13
2021	3	8	11
2022	4	4	8
2023	—	—	—
Total	$16	$ 19	$ 35

Common Stock Dividends

The Company returned $37 million of capital to shareholders in the year ended 2018 through a $0.12 dividend per common share.

On January 23, 2019, NRG declared a quarterly dividend on the Company's common stock of $0.03 per share, or $0.12 per share on an annualized basis, payable on February 15, 2019, to stockholders of record as of February 1, 2019. The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws and regulations.

Share Repurchases

In 2018, the Company's board of directors authorized the Company to repurchase $1.5 billion of its common stock. During the year ended December 31, 2018, the Company repurchased a total of 35,234,664 shares under these programs for $1.25 billion, and the remaining $250 million was repurchased by February 28, 2019. The average price paid per share for the $1.5 billion share repurchase was $36.24. In addition, the Company's board of directors authorized in February 2019 an additional $1 billion share repurchase program to be executed in 2019. See Note 14, Capital Structure, for additional discussion.

Targeted Debt Reduction

NRG is revising its balance sheet target ratios in order to further strengthen its balance sheet. In order to achieve the revised balance sheet targets, the Company is reserving up to $600 million in 2019 capital which may be allocated toward debt reduction.

Small Book Acquisitions

During 2018, the Company has acquired several books of customers totaling approximately 115,000 customers, along with brand names, for $44 million.

Petra Nova Debt Repayment

NRG has guaranteed up to $124 million of Petra Nova's $248 million project debt to its lenders for purposes of debt repayment in the event Petra Nova is unable to meet its projected debt coverage covenant as stipulated in its financing agreements. The covenant test and possible repayment, or a portion thereof, are scheduled to occur in the third quarter of 2019. Once such payment is made, NRG's guarantee will terminate.

Cash Flow Discussion

2018 compared to 2017

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

	Year ended December 31,		
(In millions)	2018	2017	Change
Net cash provided by operating activities	$1,377	$1,610	$(233)
Net cash used by investing activities	(205)	(639)	434
Net cash used by financing activities	(1,526)	(1,138)	(388)

Net Cash Provided By Operating Activities

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

	(In millions)
Change in cash from discontinued operations	$ (380)
Decrease in inventory during 2017 as a result of initiatives related to the Transformation Plan to reduce inventory levels	(112)
GenOn settlement payment in July 2018, net of insurance proceeds received in December 2018	(63)
Changes in cash collateral in support of risk management activities due to changes in commodity prices	(25)
Increase in operating income adjusted for non-cash items	323
Increase in working capital in 2018 as a result of initiatives related to the Transformation Plan to increase working capital	24
	$ (233)

Net Cash Used By Investing Activities

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

	(In millions)
Increase in proceeds from sale of assets and sale of discontinued operations	$ 1,134
Change in cash from discontinued operations	254
Decrease in net investments in unconsolidated affiliates	18
Cash removed due to deconsolidation of Agua Caliente and Ivanpah in 2018	(268)
Increase in cash paid for acquisitions in 2018, primarily for the XOOM acquisition	(229)
Decrease in net distributions received from discontinued operations	(210)
Increase in capital expenditures for growth investments and maintenance in generation assets	(134)
Increase in investments in nuclear decommissioning trust net of proceeds from sales	(48)
Decrease in sales of emissions, net of purchases	(47)
Decrease in insurance proceeds received in 2018	(22)
Decrease in cash grants received in 2018	(8)
Other	(6)
	$ 434

Net Cash Used By Financing Activities

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

	(In millions)
Repurchases of common stock in 2018, from open market repurchases and the ASR agreement	$(1,250)
Decrease in proceeds from issuance of long-term debt	(68)
Change in cash from discontinued operations	640
Decrease in payments for short and long-term debt	150
Decrease in notes issued to affiliates	99
Increase in cash received from issuance of stock due to exercise of employee share-based compensation	21
Decrease in net distributions paid to noncontrolling interests from subsidiaries	14
Other	6
	$(388)

2017 compared to 2016

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

	Year ended December 31,		
(In millions)	2017	2016	Change
Net cash provided by operating activities	$1,610	$1,908	$(298)
Net cash used by investing activities	(639)	(757)	118
Net cash used by financing activities	(1,138)	(768)	(370)

Net Cash Provided By Operating Activities

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

	(In millions)
Changes in cash collateral in support of risk management activities due to changes in commodity prices	$ (476)
Other changes in working capital	(121)
Decrease in operating income adjusted for non-cash items	(67)
Decrease in inventory as a result of initiatives related to the Transformation Plan to reduce inventory levels in 2017 as compared to 2016	83
Change in cash from discontinued operations	283
	$ (298)

Net Cash Used By Investing Activities

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

	(In millions)
Decrease in capital expenditures in 2017	$ 290
Increase in proceeds from sale of assets	189
Increase due to net distributions received from discontinued operations	208
Increase in sales of emissions, net of purchases	67
Increase in investments in nuclear decommissioning trust net of proceeds from sales	30
Change in cash from discontinued operations, primarily due to increased capital expenditures in 2017 and asset sales in 2016	(591)
Decrease in cash grants received in 2017	(28)
Increase due to net contributions to unconsolidated affiliates	(24)
Other	(23)
	$ 118

Net Cash Used By Financing Activities

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

	(In millions)
Decrease in payments for short and long-term debt primarily due to repurchases of Senior Notes in 2016	$ 3,262
Change due to repurchase of preferred stock in 2016	226
Decrease in debt extinguishment costs	79
Decrease in deferred debt issuance costs	43
Decrease in payment of dividends, due to the annualized dividend rate being reduced from $0.58/share to $0.12/share in the first quarter of 2016	38
Decrease in borrowings primarily related to Agua Caliente borrowings in 2016	(3,234)
Change in cash from discontinued operations	(652)
Decrease due to payment notes issued to affiliates in 2017	(125)
Other	(7)
	$ (370)

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

As of December 31, 2018, the Company had domestic pre-tax book income of $468 million and a foreign pre-tax book loss of $1 million. For the year ended December 31, 2018, the Company generated an NOL of $8.0 billion due to a current year taxable loss. As of December 31, 2018, the Company has cumulative domestic federal NOL carryforwards of $10.7 billion, which will begin expiring in 2031 and cumulative state NOL carryforwards of $5.6 billion. NRG also has cumulative foreign NOL carryforwards of $213 million, which do not have an expiration date.

In addition to the above NOLs, NRG has a $442 million indefinite carryforward for interest deductions, as well as $381 million of tax credits to be utilized in future years. As a result of the Company's tax position, including the benefit of $9.6 billion of tax losses and worthless stock deduction upon GenOn emerging from bankruptcy, and based on current forecasts, the Company anticipates income tax payments, primarily due to state and local jurisdictions, of up to $20 million in 2019.

The Company has recorded short-term and long-term receivables of $35 million and $34 million, respectively, representing refundable AMT credits from the IRS, which are anticipated to be received from 2019 through 2022 pursuant to the 50% annual limitation as enacted by the Tax Act upon repeal of corporate AMT effective January 1, 2018. Of this amount, short-term and long-term payables of $11 million each are due to GenOn for their share of minimum tax credits.

In addition to these amounts, the Company has $26 million of tax effected uncertain state tax benefits for which the Company has recorded a non-current tax liability of $30 million (including accrued interest) until such final resolution with the related taxing authority.

The Company is no longer subject to U.S. federal income tax examinations for years prior to 2015. With few exceptions, state and local income tax examinations are no longer open for years before 2010.

Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See also Item 15 — Note 25 Guarantees, to the Consolidated Financial Statements for additional discussion.

Retained or Contingent Interests

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

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments — As of December 31, 2018, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy-related entities that are accounted for under the equity method of accounting. One of these investments is considered a variable interest entity for which NRG is not the primary beneficiary.

NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $992 million as of December 31, 2018. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 15 — Note 15, Investments Accounted for by the Equity Method and Variable Interest Entities, to the Consolidated Financial Statements for additional discussion.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs. The following tables summarize NRG's contractual obligations and contingent obligations for guarantees. See also Item 15 — Note 11, Debt and Capital Leases, Note 21, Commitments and Contingencies, and Note 25, Guarantees, to the Consolidated Financial Statements for additional discussion.

	By Remaining Maturity at December 31, 2018					
Contractual Cash Obligations	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total [(a)]	2017 Total
	(In millions)					
Long-term debt (including estimated interest)	$464	$807	$2,349	$6,520	$10,140	$13,895
Capital lease obligations (including estimated interest)	—	1	—	—	1	5
Operating leases	61	102	91	317	571	675
Fuel purchase and transportation obligations	227	278	129	209	843	1,335
Fixed purchased power commitments	30	25	12	1	68	68
Pension minimum funding requirement [(b)]	39	53	82	79	253	205
Other postretirement benefits minimum funding requirement [(c)]	7	13	12	25	57	74
Other liabilities [(d)]	32	62	43	144	281	296
Total	$860	$1,341	$2,718	$7,295	$12,214	$16,553

(a) Excludes $26 million non-current payable relating to NRG's uncertain tax benefits under ASC 740 as the period of payment cannot be reasonably estimated. Also excludes $679 million of asset retirement obligations which are discussed in Item 15 — Note 12 , Asset Retirement Obligations, to the Consolidated Financial Statements

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

(c) These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2027 are currently not available

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

	By Remaining Maturity at December 31, 2018					
Guarantees	Under 1 Year	1-3 Years	3-5 Years	Over 5 Years	Total	2017 Total
	(In millions)					
Letters of credit and surety bonds[(a)(b)]	$1,138	$ 79	$ —	$36	$1,253	$1,003
Asset sales guarantee obligations	—	4	257	532	793	312
Other guarantees	—	105	—	616	721	645
Total guarantees	$1,138	$ 188	$ 257	$1,184	$2,767	$1,960

(a) As of December 31, 2017 excludes $92 million of letters of credit issued under the intercompany revolving credit agreement between NRG and GenOn

(b) December 31, 2018 includes $32 million of letter of credit and surety bonds for the benefit of GenOn where NRG holds cash or letter of credit to back stop the liability

Fair Value of Derivative Instruments

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

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

The tables below disclose the activities that include both exchange and non-exchange traded contracts accounted for at fair value in accordance with ASC 820, Fair Value Measurements and Disclosures, or ASC 820. Specifically, these tables disaggregate realized and unrealized changes in fair value; disaggregate estimated fair values at December 31, 2018, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2018. For a full discussion of the Company's valuation methodology of its contracts, see Derivative Fair Value Measurements in Item 15 — Note 4, Fair Value of Financial Instruments, to the Consolidated Financial Statements.

Derivative Activity Gains/(Losses)	(In millions)
Fair value of contracts as of December 31, 2017	$ 103
Contracts realized or otherwise settled during the period	(99)
Contracts acquired during the period	11
Changes in fair value	89
Fair value of contracts as of December 31, 2018	$ 104

	Fair Value of Contracts as of December 31, 2018				
	Maturity				
Fair value hierarchy (Losses)/Gains	1 Year or Less	Greater Than 1 Year to 3 Years	Greater Than 3 Years to 5 Years	Greater Than 5 Years	Total Fair Value
	(In millions)				
Level 1	$(58)	$(25)	$(4)	$—	$(87)
Level 2	106	79	(1)	(13)	171
Level 3	43	(1)	(4)	(18)	20
Total	$91	$53	$(9)	$(31)	$104

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or posted on the Company's derivative assets or liabilities are recorded on a separate line item on the balance sheet. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company's portfolio. As discussed in Item 7A — Quantitative and Qualitative Disclosures About Market Risk, Commodity Price Risk, NRG measures the sensitivity of the Company's portfolio to potential changes in market prices using VaR, a statistical model which attempts to predict risk of loss based on market price and volatility. NRG's risk management policy places a limit on one-day holding period VaR, which limits the Company's net open position. As the Company's trade-by-trade derivative accounting results in a gross-up of the Company's derivative assets and liabilities, the net derivative assets and liability position is a better indicator of NRG's hedging activity. As of December 31, 2018, NRG's net derivative asset was $104 million, an increase to total fair value of $1 million as compared to December 31, 2017. This increase was primarily driven by gains in fair value and contracts acquired during the period, largely offset by roll off trades that were settled during the period.

Based on a sensitivity analysis using simplified assumptions, the impact of a $0.50 per MMBtu increase in natural gas prices across the term of the derivative contracts would result in a decrease of approximately $230 million in the net value of derivatives as of December 31, 2018.

The impact of a $0.50 per MMBtu decrease in natural gas prices across the term of the derivative contracts would result in an increase of approximately $221 million in the net value of derivatives as of December 31, 2018.

Critical Accounting Policies and Estimates

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

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

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

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

Judgment about likelihood of event(s) occurring
Regulatory and political environments and requirements

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Derivative Instruments

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

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

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

Income Taxes and Valuation Allowance for Deferred Tax Assets

As of December 31, 2018, NRG had a valuation allowance of $3.8 billion. This amount is comprised of domestic federal net deferred tax assets of approximately $3.3 billion, domestic state net deferred tax assets of $454 million, foreign net operating loss carryforwards of $62 million and foreign capital loss carryforwards of approximately $1 million. The Company believes it is more likely than not that the results of future operations will not generate sufficient taxable income which includes the future reversal of existing taxable temporary differences to realize deferred tax assets, requiring a valuation allowance to be recorded.

NRG continues to be under audit for multiple years by taxing authorities in other jurisdictions. Considerable judgment is required to determine the tax treatment of a particular item that involves interpretations of complex tax laws, including the impact of the Tax Cuts and Jobs Act effective December 22, 2017. NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions, including operations located in Australia.

The Company is no longer subject to U.S. federal income tax examinations for years prior to 2015. With few exceptions, state and local income tax examinations are no longer open for years before 2010.

Evaluation of Assets for Impairment and Other-Than-Temporary Decline in Value

In accordance with ASC 360, Property, Plant, and Equipment, or ASC 360, NRG evaluates property, plant and equipment and certain intangible assets for impairment whenever indicators of impairment exist. Examples of such indicators or events are:

- Significant decrease in the market price of a long-lived asset;
- Significant adverse change in the manner an asset is being used or its physical condition;
- Adverse business climate;

- Accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset;
- Current period loss combined with a history of losses or the projection of future losses; and
- Change in the Company's intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold, or disposed of before the end of its previously estimated useful life

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset, through considering project specific assumptions for long-term power prices, escalated future project operating costs and expected plant operations. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the different courses of action available to the Company. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. NRG uses its best estimates in making these evaluations and considers various factors, including forward price curves for energy, fuel and operating costs. However, actual future market prices and project costs could vary from the assumptions used in the Company's estimates, and the impact of such variations could be material.

For assets to be held and used, if the Company determines that the undiscounted cash flows from the asset are less than the carrying amount of the asset, NRG must estimate fair value to determine the amount of any impairment loss. Assets held-for-sale are reported at the lower of the carrying amount or fair value less the cost to sell. The estimation of fair value under ASC 360, whether in conjunction with an asset to be held and used or with an asset held-for-sale, and the evaluation of asset impairment are, by their nature, subjective. NRG considers quoted market prices in active markets to the extent they are available. In the absence of such information, the Company may consider prices of similar assets, consult with brokers, or employ other valuation techniques. NRG will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as previously discussed with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in the Company's estimates, and the impact of such variations could be material.

Annually, during the fourth quarter, the Company revises its views of power and fuel prices including the Company's fundamental view for long term prices, forecasted generation and operating and capital expenditures, in connection with the preparation of its annual budget. Changes to the Company's views of long term power and fuel prices impacted the Company's projections of profitability, based on management's estimate of supply and demand within the sub-markets for its operations and the physical and economic characteristics of each of its businesses. During the fourth quarter of 2018, the Company completed its annual budget and revised its view of long-term power and fuel prices and the corresponding impact on estimated cash flows associated with its long-lived assets. There were no significant changes to the Company's long-term view of natural gas prices despite management's expectation of continued trends towards more renewables and energy storage. There were minimal changes to the long-term view of energy and capacity prices, which did not have a significant negative impact on the Company's coal, nuclear, and renewable facilities.

The following long-lived asset impairment was recorded during 2018, as further described in Item 15 —Note 9, Asset Impairments, to the consolidated financial statements:

Guam— During the fourth quarter of 2018, the Company concluded its wholly-owned subsidiary, NRG Solar Guam, LLC, was held for sale after board approval and advanced negotiations to sell the business. Accordingly, the Company recorded the assets and liabilities at fair market value as of December 31, 2018 based on the contractual sale price, which resulted in an impairment loss of $12 million. The sale was completed on February 20, 2019.

Keystone and Conemaugh — On June 29, 2018, the Company entered into an agreement to sell its approximately 3.7% interests in the Keystone and Conemaugh generating stations. The Company recorded impairment losses of $14 million for Keystone and $14 million for Conemaugh to adjust the carrying amount of the assets to fair value based on the contractual sale price. The transaction closed on September 5, 2018.

Dunkirk — During the second quarter of 2018, NRG ceased its development of the project to add gas capability at the Dunkirk generating station. The project was put on hold in 2015 pending the resolution of a lawsuit filed by Entergy Corporation against the NYPSC, which challenged the legality of its contract with Dunkirk. The lawsuit was later dropped and development continued, but the delay imposed a new requirement on Dunkirk to enter into the NYISO interconnection study process. The NYISO studies have concluded that extensive electric system upgrades would be necessary for the station to return to service. This would cause the Company to incur a material increase in cost and delay the project schedule that would render the project impractical. Consequently, the Company has recorded an impairment loss of $46 million, reducing the carrying amount of the related assets to $0.

Other Impairments — As of December 31, 2018, the Company recorded additional impairment losses of approximately $13 million. These impairment losses were primarily to record the value of certain long-lived assets, including property, plant and equipment and intangible assets, at fair market value at the date of sale or in connection with an impairment indicator.

Equity and Cost Method Investments — NRG is also required to evaluate its equity method and cost method investments to determine whether or not they are impaired in accordance with ASC 323, Investments - Equity Method and Joint Ventures, or ASC 323. The standard for determining whether an impairment must be recorded under ASC 323 is whether a decline in the value is considered an other-than-temporary decline in value. The evaluation and measurement of impairments under ASC 323 involves the same uncertainties as described for long-lived assets that the Company owns directly and accounts for in accordance with ASC 360. Similarly, the estimates that NRG makes with respect to its equity and cost method investments are subjective, and the impact of variations in these estimates could be material. Additionally, if the projects in which the Company holds these investments recognize an impairment under the provisions of ASC 360, NRG would record its proportionate share of that impairment loss and would evaluate its investment for an other-than-temporary decline in value under ASC 323. During the year ended December 31, 2018, the Company recorded impairment losses on its equity method investments of $15 million due to declines in value.

Goodwill and Other Intangible Assets

At December 31, 2018, NRG reported goodwill of $573 million, consisting of $165 million associated with the acquisition of Midwest Generation and $408 million for retail business acquisitions. The balance of goodwill increased by $34 million in 2018 due to the acquisition of XOOM.

The Company applies ASC 805, Business Combinations, or ASC 805, and ASC 350, to account for its goodwill and intangible assets. Under these standards, the Company amortizes all finite-lived intangible assets over their respective estimated weighted-average useful lives, while goodwill has an indefinite life and is not amortized. Goodwill is tested for impairment at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Company tests goodwill for impairment at the reporting unit level, which is identified by assessing whether the components of the Company's operating segments constitute businesses for which discrete financial information is available and whether segment management regularly reviews the operating results of those components. The Company performs the annual goodwill impairment assessment as of December 31 or when events or changes in circumstances indicate that the carrying value may not be recoverable. The Company first assesses qualitative factors to determine whether it is more likely than not that an impairment has occurred. In the absence of sufficient qualitative factors, the Company performs a quantitative assessment by determining the fair value of the reporting unit and comparing to its book value. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary, the Company's goodwill will be impaired at that time.

The Company performed its qualitative assessment of macroeconomic, industry and market events and circumstances, and the overall financial performance of the NRG Business Solutions and Commodity Retail reporting units. The Company determined it was more likely than not that the fair value of the goodwill attributed to these reporting units were more than their carrying amount and accordingly, no impairment existed for the year ended December 31, 2018.

The Company performed a quantitative assessment for the reporting units in the following table. The Company determined the fair value of these reporting units using primarily an income approach. Under the income approach, the Company estimated the fair value of the reporting units' invested capital exceeds its carrying value and, as such, the Company concluded that goodwill associated with the reporting units in the following table is not impaired as of December 31, 2018:

Reporting Unit	% Fair Value Over Carrying Value	
Midwest Generation (Generation Segment)	132	%
Texas Non-Commodity (Retail Segment)	135	%

The Company believes the methodology and assumptions used in its quantitative assessment are consistent with the views of market participants. Significant inputs to the determination of fair value were as follows:

- The Company applied a discounted cash flow methodology to the long-term forecasts for all of the plants in the region. The significant assumptions used to derive the long-term budgets used in the income approach are affected by the following key inputs:

The Company's views of power and fuel prices consider market prices for the first five-year period and the Company's fundamental view for the longer term, driven by the Company's long-term view of the price of natural gas. The Company's fundamental view for the longer term reflects the implied power price and heat rate that would support new build of a combined cycle gas plant. The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants. Hedging is included to the extent of contracts already in place;

- The Company's estimate of generation, fuel costs, capital expenditure requirements and the existing and anticipated impact of environmental regulations;
- The Company's fundamental view for the longer term, cash flows for the plants in the region were included in the fair value calculation through the end of each plants' estimated useful life; and
- Projected generation and resulting energy gross margin in the long-term forecasts is based on an hourly dispatch that simulates dispatch of each unit into the power market. The dispatch simulation is based on power prices, fuel prices, and the physical and economic characteristics of each plant
- The Company applied a discounted cash flow methodology to the long-term budget for the Texas Non-Commodity reporting unit. The significant assumptions used to derive the long-term budgets used in the income approach are affected by the following key inputs: a terminal value utilizing assumed growth rates and discount rates that reflect the inherent cash flow risk for each reporting unit.

Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of the annual goodwill impairment test will prove to be accurate predictions of the future.

Contingencies

NRG records reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. Gain contingencies are not recorded until management determines it is certain that the future event will become or does become a reality. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events, and estimates of the financial impacts of such events. NRG describes in detail its contingencies in Item 15 — Note 21, Commitments and Contingencies, to the consolidated financial statements.

Recent Accounting Developments

See Item 15 — Note 2, Summary of Significant Accounting Policies, to the consolidated financial statements for a discussion of recent accounting developments.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

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

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

Commodity Price Risk

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

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

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

As of December 31, 2018, the VaR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the VaR model was $44 million.

The following table summarizes average, maximum and minimum VaR for NRG for the years ended December 31, 2018 and 2017:

(In millions)	2018	2017
VaR as of December 31,	$ 44	$ 46
For the year ended December 31,		
Average	$ 59	$ 51
Maximum	75	66
Minimum	44	40

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

In order to provide additional information, the Company also uses VaR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VaR for the derivative financial instruments calculated using the diversified VaR model for the entire term of these instruments entered into for both asset management and trading was $14 million as of December 31, 2018, primarily driven by asset-backed transactions.

Interest Rate Risk

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

In addition to those discussed above, the Company's project subsidiaries enter into interest rate swaps, intended to hedge the risks associated with interest rates on non-recourse project level debt. See Item 15 — Note 11, Debt and Capital Leases, to the Consolidated Financial Statements, for more information about interest rate swaps of the Company's project subsidiaries.

If all of the above swaps had been discontinued on December 31, 2018, the counterparties would have owed the Company $37 million. Based on the investment grade rating of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of December 31, 2018, a 1% change in interest rates would result in a $7 million change in interest expense on a rolling twelve month basis.

As of December 31, 2018, the Company's debt fair value was $6.7 billion and carrying value was $6.6 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company's long-term debt by $510 million.

Liquidity Risk

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

Based on a sensitivity analysis for power and gas positions under marginable contracts, a $0.50 per MMBtu change in natural gas prices across the term of the marginable contracts would cause a change in margin collateral posted of approximately $125 million as of December 31, 2018, and a 1.00 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $62 million as of December 31, 2018. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of December 31, 2018.

Counterparty Credit Risk

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

As of December 31, 2018, aggregate counterparty credit exposure to a significant portion of the Company's counterparties totaled $301 million, of which the Company held collateral (cash and letters of credit) against those positions of $123 million resulting in a net exposure of $180 million. Approximately 66% of the Company's exposure before collateral is expected to roll off by the end of 2020. The following table highlights the net counterparty credit exposure by industry sector and by counterparty credit quality. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market, NPNS, and non-derivative transactions. As of December 31, 2018, the aggregate credit exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure [(a)] [(b)] (% of Total)	
Financial institutions	11	%
Utilities, energy merchants, marketers and other	89	
Total	100	%

Category	Net Exposure [(a)] [(b)] (% of Total)	
Investment grade	49	%
Non-Investment grade/Non-Rated	51	
Total	100	%

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

(b) The figures in the tables above exclude potential counterparty credit exposure related to RTOs, ISOs, registered commodity exchanges and certain long term contracts

The Company currently has no exposure to any individual wholesale counterparty in excess of 10% of the total net exposure discussed above as of December 31, 2018. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, the Company does not anticipate a material impact on its financial position or results of operations from nonperformance by any counterparty.

RTOs and ISOs

The Company participates in the organized markets of CAISO, ERCOT, ISO-NE, MISO, NYISO and PJM, known as RTOs or ISOs. Trading in these markets is approved by FERC, or in the case of ERCOT, approved by the PUCT and include credit policies that, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. As a result, the counterparty credit risk to these markets is limited to NRG’s applicable share of the overall market and are excluded from the above exposures.

Exchange Traded Transactions

The Company enters into commodity transactions on registered exchanges, notably ICE and NYMEX. These clearinghouses act as the counterparty and transactions are subject to extensive collateral and margining requirements. As a result, these commodity transactions have limited counterparty credit risk.

Long Term Contracts

Counterparty credit exposure described above excludes credit risk exposure under certain long term contracts, including California tolling agreements and solar PPAs. As external sources or observable market quotes are not available to estimate such exposure, the Company values these contracts based on various techniques including, but not limited to, internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Based on these valuation techniques, as of December 31, 2018, aggregate credit risk exposure managed by NRG to these counterparties was approximately $434 million for the next five years. This amount excludes potential credit exposures for projects with long-term PPAs that have not reached commercial operations and any exposure for entities classified as a discontinued operation.

NRG through its unconsolidated affiliates Ivanpah and Agua Caliente has exposure to PG&E of approximately $321 million for the next five years. As a result of the bankruptcy filing by PG&E on January 29, 2019, it is uncertain whether and to what extent the bankruptcy may have on these contracts. For further discussion see Note 15 Investments Accounted for by the Equity Method and Variable Interest Entities.

Retail Customer Credit Risk

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

As of December 31, 2018, the Company's retail customer credit exposure to C&I and Mass customers was diversified across many customers and various industries, as well as government entities. The Company is also subject to risk with respect to its residential solar customers. The Company's bad debt expense resulting from credit risk was $85 million, $68 million, and $45 million for the years ending December 31, 2018, 2017, and 2016, respectively. Current economic conditions may affect the Company's customers' ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Credit Risk Related Contingent Features

Certain of the Company's hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed "adequate assurance" under the agreements, or require the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts that have adequate assurance clauses that are in a net liability position as of December 31, 2018 was $16 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2018 was $14 million. The Company is also a party to certain marginable agreements under which it has a net liability position, but the counterparty has not called for the collateral due, which is approximately $11 million as of December 31, 2018.

Currency Exchange Risk

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

Item 8 — Financial Statements and Supplementary Data

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

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

None.

Item 9A — Controls and Procedures

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

Under the supervision and with the participation of NRG's management, including its principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures, as such term is defined in Rules 13a-15(e) or 15d-15(e) of the Exchange Act. Based on this evaluation, the Company's principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this Annual Report on Form 10-K. Management's report on the Company's internal control over financial reporting and the report of the Company's independent registered public accounting firm are incorporated under the caption "Management's Report on Internal Control over Financial Reporting" and under the caption "Report of Independent Registered Public Accounting Firm" in this Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

Changes in Internal Control over Financial Reporting

There were no changes in NRG’s internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred in the fourth quarter of 2018 that materially affected, or are reasonably likely to materially affect, NRG’s internal control over financial reporting.

Inherent Limitations over Internal Controls

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

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

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

Management's Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in Internal Control — Integrated Framework (2013), the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2018.

On June 1, 2018, we acquired XOOM Energy, LLC, as further described in Note 3, Acquisitions, Discontinued Operations and Dispositions. XOOM Energy, LLC's assets comprised approximately 2.1% of the Company's total assets as of December 31, 2018 and approximately 2.3% of the Company's total revenues for the year ended

December 31, 2018. As of December 31, 2018, we are in the process of evaluating the internal controls of the acquired business and integrating it into our existing operations.

The acquired business has, therefore, been excluded from management's assessment of internal control over financial reporting for the year ended December 31, 2018.
The effectiveness of the Company's internal control over financial reporting as of December 31, 2018 has been audited by KPMG LLP, the Company's independent registered public accounting firm, as stated in its report which is included in this Annual Report on Form 10 K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control Over Financial Reporting

We have audited NRG Energy, Inc.'s and subsidiaries (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income/(loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes and financial statement schedule II (collectively, the consolidated financial statements), and our report dated February 28, 2019 expressed an unqualified opinion on those consolidated financial statements.

Management excluded XOOM Energy, LLC (XOOM), acquired by the Company during 2018, from their assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. XOOM's assets comprised approximately 2.1% of the Company's total assets as of December 31, 2018 and approximately 2.3% of the Company's total revenues for the year ended December 31, 2018. Our audit of the Company's internal control over financial reporting also excluded XOOM.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

(signed) KPMG LLP

Philadelphia, Pennsylvania
February 28, 2019

Item 9B — Other Information

None.

PART III
Item 10 — Directors, Executive Officers and Corporate Governance
Directors
E. Spencer Abraham has been a director of NRG since December 2012. Previously, he served as a director of GenOn Energy, Inc. from January 2012 to December 2012. He is Chairman and Chief Executive Officer of The Abraham Group, an international strategic consulting firm based in Washington, D.C. which he founded in 2005. Prior to that, Secretary Abraham served as Secretary of Energy under President George W. Bush from 2001 through January 2005 and was a U.S. Senator for the State of Michigan from 1995 to 2001. Secretary Abraham serves on the boards of the following public companies: Occidental Petroleum Corporation, PBF Energy and Two Harbors Investment Corp., as well as chairman of the board of Uranium Energy Corp. He also serves on the board of C3 IoT, a private company. Secretary Abraham previously served as the non-executive chairman of AREVA, Inc., the U.S. subsidiary of the French-owned nuclear company, and as a director of Deepwater Wind LLC, International Battery, Green Rock Energy, ICx Technologies, PetroTiger and Sindicatum Sustainable Resources. He also previously served on the advisory board or committees of Midas Medici (Utilipoint), Millennium Private Equity, Sunovia and Wetherly Capital.
Matthew Carter, Jr. has been a director of NRG since March 2018. Mr. Carter currently serves as Chief Executive Officer of Aryaka Networks, Inc. Mr. Carter served as President and Chief Executive Officer and a director of Inteliquent, Inc., a publicly traded provider of voice telecommunications services, from June 2015 until February 2017 when Inteliquent, Inc. was acquired. He served as President of the Sprint Enterprise Solutions business unit of Sprint Corporation, a publicly traded telecommunications company, from September 2013 until January 2015 and, previous to that position, served as President, Sprint Global Wholesale & Emerging Solutions at Sprint Nextel Corporation. Mr. Carter also serves as a director of Jones Lang Lasalle Incorporated. He previously served as a director of USG Corporation from 2012 to 2018, Apollo Education Group, Inc. from 2012 to 2017 and Inteliquent, Inc. from June 2015 to February 2017 and has significant marketing, technology and international experience, including previous management oversight for all of Inteliquent, Inc.'s operations.
Lawrence S. Coben has served as Chairman of the Board since February 2017, and has been a director of NRG since December 2003. He was Chairman and Chief Executive Officer of Tremisis Energy Corporation LLC until December 2017. Dr. Coben was Chairman and Chief Executive Officer of both Tremisis Energy Acquisition Corporation II, a publicly held company, from July 2007 through March 2009 and of Tremisis Energy Acquisition Corporation from February 2004 to May 2006. From January 2001 to January 2004, he was a Senior Principal of Sunrise Capital Partners L.P., a private equity firm. From 1997 to January 2001, Dr. Coben was an independent consultant. From 1994 to 1996, Dr. Coben was Chief Executive Officer of Bolivian Power Company. Dr. Coben serves on the board of Freshpet, Inc. and served on the advisory board of Morgan Stanley Infrastructure II, L.P. from September 2014 through December 2016. Dr. Coben is also Executive Director of the Sustainable Preservation Initiative and a Consulting Scholar at the University of Pennsylvania Museum of Archaeology and Anthropology.
Heather Cox has been a director of NRG since March 2018. Ms. Cox currently serves as Chief Digital Health and Analytics Officer at Humana Inc. Ms. Cox was Executive Vice President, Chief Technology & Digital Officer of United Services Automobile Association, Inc. from October 2016 to March 2018. Ms. Cox served as Chief Executive Officer, Financial Technology Division and Head of Citi FinTech of Citigroup, Inc. from November 2015 to September 2016, and as Chief Client Experience, Digital and Marketing Officer, Global Consumer Bank of Citigroup, Inc. from April 2014 to November 2015. Prior to that, Ms. Cox served at Capital One Financial Corporation for six years, most recently as Executive Vice President, US Card Operations, Capital One from August 2011 to August 2014. Ms. Cox also served in various managerial and executive roles at E*Trade Bank for ten years.
Terry G. Dallas has been a director of NRG since December 2012. Previously, he served as a director of GenOn Energy, Inc. from December 2010 to December 2012. Mr. Dallas served as a director of Mirant Corporation from 2006 until December 2010. Mr. Dallas was also the former Executive Vice President and Chief Financial Officer of Unocal Corporation, an oil and gas exploration and production company prior to its merger with Chevron Corporation, from 2000 to 2005. Prior to that, Mr. Dallas held various executive finance positions in his 21-year career with Atlantic Richfield Corporation, an oil and gas company with major operations in the United States, Latin America, Asia, Europe and the Middle East. Mr. Dallas is an "audit committee financial expert" as defined by the SEC

rules.

Mauricio Gutierrez has served as President and Chief Executive Officer of NRG since December 2015 and as a director of NRG since January 2016. Prior to December 2015, Mr. Gutierrez was the Executive Vice President and Chief Operating Officer of NRG from July 2010 to December 2015. Mr. Gutierrez also served as the Interim President and Chief Executive Officer of Clearway Energy, Inc. from December 2015 to May 2016 and Executive Vice President and Chief Operating Officer of Clearway Energy, Inc. from December 2012 to December 2015. Mr. Gutierrez has also served on the board of Clearway Energy, Inc. from December 2012 until August 2018. Mr. Gutierrez has been with NRG since August 2004 and served in multiple executive positions within NRG including Executive Vice President - Commercial Operations from January 2009 to July 2010 and Senior Vice President - Commercial Operations from March 2008 to January 2009. Prior to joining NRG in August 2004, Mr. Gutierrez held various commercial positions within Dynegy, Inc.

William E. Hantke has been a director of NRG since March 2006. Mr. Hantke served as Executive Vice President and Chief Financial Officer of Premcor, Inc., a refining company, from February 2002 until December 2005. Mr. Hantke was Corporate Vice President of Development of Tosco Corporation, a refining and marketing company, from September 1999 until September 2001, and he also served as Corporate Controller from December 1993 until September 1999. Prior to that position, he was employed by Coopers & Lybrand as Senior Manager, Mergers and Acquisitions from 1989 until 1990. He also held various positions from 1975 until 1988 with AMAX, Inc., including Corporate Vice President, Operations Analysis and Senior Vice President, Finance and Administration, Metals and Mining. He was employed by Arthur Young from 1970 to 1975 as Staff/Senior Accountant. Mr. Hantke was Non-Executive Chairman of Process Energy Solutions, a private alternative energy company until March 31, 2008 and served as director and Vice-Chairman of NTR Acquisition Co., an oil refining start-up, until January 2009. Mr. Hantke has served on the board of PBF Energy Inc. since February 2016.

Paul W. Hobby has been a director of NRG since March 2006. Mr. Hobby is the Managing Partner of Genesis Park, L.P., a Houston-based private equity business specializing in technology and communications investments which he founded in 1999. Mr. Hobby routinely provides management and governance services to Genesis Park portfolio companies, and is currently serving as Chairman of Texas Monthly. He previously served as the Chief Executive Officer of Alpheus Communications, Inc., a Texas wholesale telecommunications provider from 2004 to 2011, and as Former Chairman of CapRock Services Corp., the largest provider of satellite services to the global energy business from 2002 to 2006. From November 1992 until January 2001, he served as Chairman and Chief Executive Officer of Hobby Media Services and was Chairman of Columbine JDS Systems, Inc. from 1995 until 1997. Mr. Hobby is former Chairman of the Houston Branch of the Federal Reserve Bank of Dallas and the Greater Houston Partnership and is former Chairman of the Texas Ethics Commission. He was an Assistant U.S. Attorney for the Southern District of Texas from 1989 to 1992, Chief of Staff to the Lieutenant Governor of Texas, Bob Bullock and an Associate at Fulbright & Jaworski from 1986 to 1989.

Anne C. Schaumburg has been a director of NRG since April 2005. From 1984 until her retirement in January 2002, she was Managing Director of Credit Suisse First Boston and a senior banker in the Global Energy Group. Ms. Schaumburg has worked in the Investment Banking industry for 28 years specializing in the power sector. She ran Credit Suisse's Power Group from 1994 - 1999, prior to its consolidation with Natural Resources and Project Finance, where she was responsible for assisting clients on advisory and finance assignments. Her transaction expertise, across the spectrum of utility and unregulated power, includes mergers and acquisitions, debt and equity capital market financings, project finance and leasing, utility disaggregation and privatizations. Ms. Schaumburg is also a director of Brookfield Infrastructure Partners since 2008 and chair of the Audit Committee.

Thomas H. Weidemeyer has been a director of NRG since December 2003. Until his retirement in December 2003, Mr. Weidemeyer served as Director, Senior Vice President and Chief Operating Officer of United Parcel Service, Inc., the world's largest transportation company and President of UPS Airlines. Mr. Weidemeyer became Manager of the Americas International Operation in 1989, and in that capacity directed the development of the UPS delivery network throughout Central and South America. In 1990, Mr. Weidemeyer became Vice President and Airline Manager of UPS Airlines and, in 1994, was elected its President and Chief Operating Officer. Mr. Weidemeyer became Senior Vice President and a member of the Management Committee of United Parcel Service, Inc. that same year, and he became Chief Operating Officer of United Parcel Service, Inc. in January 2001. Mr. Weidemeyer also serves as a director of The Goodyear Tire & Rubber Co., Waste Management, Inc. and Amsted Industries Incorporated.

Executive Officers

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

Kirkland Andrews has served as Executive Vice President and Chief Financial Officer of NRG Energy since September 2011. Mr. Andrews also served as Executive Vice President, Chief Financial Officer of Clearway Energy, Inc. from December 2012 to November 2016. Prior to joining NRG, he served as Managing Director and Co-Head Investment Banking, Power and Utilities - Americas at Deutsche Bank Securities from June 2009 to September 2011. Prior to this, he served in several capacities at Citigroup Global Markets Inc., including Managing Director, Group

Head, North American Power from November 2007 to June 2009, and Head of Power M&A, Mergers and Acquisitions from July 2005 to November 2007. Mr. Andrews serves on the board of RPM International Inc. and previously served on the board of Clearway Energy, Inc. from December 2012 until August 2018. In his banking career, Mr. Andrews led multiple large and innovative strategic, debt, equity and commodities transactions.

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

Brian Curci has served as Senior Vice President, General Counsel of NRG since March 2018. Prior to March 2018, Mr. Curci served as Deputy General Counsel and has served in various roles in over ten years with NRG, including as Corporate Secretary from October 2011 to July 2018. Prior to NRG, Mr. Curci was a corporate associate with the law firm Saul Ewing LLP in Philadelphia.

Robert Gaudette has served Senior Vice President, Business Solutions of NRG since December 2013. In this role, Mr. Gaudette oversees NRG's broad portfolio of products and services for the commercial and industrial customers. Prior to December 2013, Mr. Gaudette was Senior Vice President C&I and Origination, starting in August 2013, and Senior Vice President - Product Development & Origination following the acquisition of GenOn in December 2012. Mr. Gaudette served as Senior Vice President and Chief Commercial Officer at GenOn from December 2010 to December 2012 and served as Vice President of Mirant's Mid-Atlantic business unit from August 2009 to December 2010. During his career at Mirant, which began in 2001, Mr. Gaudette worked in various other capacities including Director of West Power, Director of NYMEX Trading, Assistant to the Chief Operating Officer and NYMEX natural gas trader.

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

Christopher Moser has served as Executive Vice President, Operations of NRG since January 2018. Mr. Moser previously served as Senior Vice President, Operations of NRG, with responsibility for Plant Operations, Commercial Operations, Business Operations and Engineering and Construction, beginning in March 2016. From June 2010 to March 2016, Mr. Moser served as Senior Vice President, Commercial Operations. In this capacity, he was responsible for the optimization of the Company's wholesale generation fleet.

Code of Ethics

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

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

Item 11 — Executive Compensation

Information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

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

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights		(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)	
Equity compensation plans approved by security holders	4,925,061	(1)	$ 21.15	11,495,799	
Equity compensation plans not approved by security holders	520,182	(2)	25.85	—	(4)
Total	5,445,243		$ 23.22	11,495,799	(3)

(1) Consists of shares issuable under the NRG LTIP and the ESPP. The NRG LTIP became effective upon the Company's emergence from bankruptcy. On April 27, 2017, the NRG LTIP was amended and restated to increase the number of shares available for issuance to 25,000,000. The ESPP, as amended and restated, was approved by the Company's stockholders on April 27, 2017, and became effective April 28, 2017. As of December 31, 2018, there were 2,931,188 shares reserved from the Company's treasury shares for the ESPP.

(2) Consists of shares issuable under the NRG GenOn LTIP. On December 14, 2012, in connection with the Merger, NRG assumed the GenOn Energy, Inc. 2010 Omnibus Incentive Plan and changed the name to the NRG 2010 Stock Plan for GenOn Employees, or the NRG GenOn LTIP. While the GenOn Energy, Inc. 2010 Omnibus Incentive Plan was previously approved by stockholders of RRI Energy, Inc. before it became GenOn, the plan is listed as "not approved" because the NRG GenOn LTIP was not subject to separate line item approval by NRG's stockholders when the Merger (which included the assumption of this plan) was approved. As part of the Merger, NRG also assumed the GenOn Energy, Inc. 2002 Long-Term Incentive Plan, the GenOn Energy, Inc. 2002 Stock Plan, and the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. NRG has no intention of making any grants or awards of its own equity securities under these plans. The number of securities to be issued upon the exercise of outstanding awards under these plans is 217,709 at a weighted-average exercise price of $34.13. See Item 15 — Note 19, Stock-Based Compensation, to Consolidated Financial Statements for a discussion of the NRG GenOn LTIP.

(3) Consists of 8,564,611 shares of common stock under NRG's LTIP and 2,931,188 shares of treasury stock reserved for issuance under the ESPP.

(4) Upon adoption of the NRG Amended and Restated LTIP effective April 27, 2017, no securities remain available for future issuance under the NRG GenOn LTIP. See Note 19, Stock-Based Compensation, for additional information.

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

Other information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

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

Information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

Item 14 — Principal Accounting Fees and Services

Information required by this Item will be incorporated by reference to the similarly named section of NRG's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

The following consolidated financial statements of NRG Energy, Inc. and related notes thereto, together with the reports thereon of KPMG LLP, are included herein:

Consolidated Statements of Operations — Years ended December 31, 2018, 2017, and 2016
Consolidated Statements of Comprehensive Income/(Loss) — Years ended December 31, 2018, 2017, and 2016
Consolidated Balance Sheets — As of December 31, 2018 and 2017
Consolidated Statements of Cash Flows — Years ended December 31, 2018, 2017, and 2016
Consolidated Statements of Stockholders' Equity — Years ended December 31, 2018, 2017, and 2016
Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedule

The following Consolidated Financial Statement Schedule of NRG Energy, Inc. is filed as part of Item 15 of this report and should be read in conjunction with the Consolidated Financial Statements.

Schedule II — Valuation and Qualifying Accounts

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.

(a)(3) Exhibits: See Exhibit Index submitted as a separate section of this report.

(b) Exhibits

See Exhibit Index submitted as a separate section of this report.

(c) Not applicable

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of NRG Energy, Inc. and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income/(loss), stockholders' equity, and cash flows for each of the years in the three year period ended December 31, 2018, and the related notes and financial statement schedule II (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2018, the Company has adopted Financial Accounting Standard Board-Accounting Standards Codification Topic 606, Revenue from Contracts with Customers, and related amendments.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

(signed) KPMG LLP

We have served as the Company's auditor since 2004.

Philadelphia, Pennsylvania
February 28, 2019

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
(In millions, except per share amounts)	2018	2017	2016
Operating Revenues			
Total operating revenues	$9,478	$9,074	$8,915
Operating Costs and Expenses			
Cost of operations	7,108	6,886	6,676
Depreciation and amortization	421	596	756
Impairment losses	99	1,534	483
Selling, general and administrative	799	836	1,032
Reorganization costs	90	44	—
Development costs	11	22	48
Total operating costs and expenses	8,528	9,918	8,995
Other income - affiliate	—	87	193
Gain/(loss) on sale of assets	32	16	(80)
Operating Income/(Loss)	982	(741)	33
Other Income/(Expense)			
Equity in earnings/(losses) of unconsolidated affiliates	9	(14)	(18)
Impairment losses on investments	(15)	(79)	(268)
Other income, net	18	51	47
Loss on debt extinguishment, net	(44)	(49)	(142)
Interest expense	(483)	(557)	(583)
Total other expense	(515)	(648)	(964)
Income/(Loss) from Continuing Operations Before Income Taxes	467	(1,389)	(931)
Income tax expense/(benefit)	7	(44)	25
Net Income/(Loss) from Continuing Operations	460	(1,345)	(956)
(Loss)/income from discontinued operations, net of income tax	(192)	(992)	65
Net Income/(Loss)	268	(2,337)	(891)
Less: Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	—	(184)	(117)
Net Income/(Loss) Attributable to NRG Energy, Inc.	268	(2,153)	(774)
Dividends for preferred shares	—	—	5
Gain on redemption of preferred shares	—	—	(78)
Income/(Loss) Available for Common Stockholders	$268	$(2,153)	$(701)
Earnings/(Loss) Per Share Attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding — basic	304	317	316
Income/(loss) from continuing operations per weighted average common share — basic	$1.51	$(3.66)	$(2.42)
(Loss)/income from discontinued operations per weighted average common share — basic	$(0.63)	$(3.13)	$0.20
Net Income/(Loss) per Weighted Average Common Share — Basic	$0.88	$(6.79)	$(2.22)
Weighted average number of common shares outstanding — diluted	308	317	316
Income/(loss) from continuing operations per weighted average common share — diluted	$1.49	$(3.66)	$(2.42)
(Loss)/income from discontinued operations per weighted average common share — diluted	$(0.62)	$(3.13)	$0.20
Net Income/(Loss) per Weighted Average Common Share — Diluted	$0.87	$(6.79)	$(2.22)
Dividends Per Common Share	$0.12	$0.12	$0.24

See notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Net Income/(Loss)	$268	$(2,337)	$(891)
Other Comprehensive (Loss)/Income, net of tax			
Unrealized gain on derivatives, net of income tax expense of $0, $1, and $1	23	13	35
Foreign currency translation adjustments, net of income tax benefit of $0, $(2), and $0	(11)	12	(1)
Available-for-sale securities, net of income tax expense of $0, $10, and $0	1	(8)	1
Defined benefit plan, net of income tax (benefit)/expense of $0, $(21), and $0	(35)	46	3
Other comprehensive (loss)/income	(22)	63	38
Comprehensive Income/(Loss)	246	(2,274)	(853)
Less: Comprehensive income/(loss) attributable to noncontrolling interests and redeemable noncontrolling interests	14	(179)	(117)
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	232	(2,095)	(736)
Dividends for preferred shares	—	—	5
Gain on redemption of preferred shares	—	—	(78)
Comprehensive Income/(Loss) Available for Common Stockholders	$232	$(2,095)	$(663)

See notes to Consolidated Financial Statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2018	2017
	(In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$563	$770
Funds deposited by counterparties	33	37
Restricted cash	17	279
Accounts receivable - trade	1,019	900
Inventory	412	453
Derivative instruments	764	624
Cash collateral posted in support of energy risk management activities	287	171
Accounts receivable - affiliate	5	180
Prepayments and other current assets	302	163
Current assets - held-for-sale	1	116
Current assets - discontinued operations	197	744
Total current assets	3,600	4,437
Property, plant and equipment, net	3,048	5,974
Other Assets		
Equity investments in affiliates	412	182
Goodwill	573	539
Intangible assets, net	591	507
Nuclear decommissioning trust fund	663	692
Derivative instruments	317	159
Deferred income taxes	46	6
Other non-current assets	289	310
Non-current assets - held-for-sale	77	43
Non-current assets - discontinued operations	1,012	10,506
Total other assets	3,980	12,944
Total Assets	$10,628	$23,355

See notes to Consolidated Financial Statements.

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

	As of December 31,	
	2018	2017
	(In millions, except share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$72	$204
Accounts payable	862	684
Accounts payable - affiliate	1	57
Derivative instruments	673	537
Cash collateral received in support of energy risk management activities	33	37
Accrued expenses and other current liabilities	680	756
Accrued expenses and other current liabilities - affiliate	—	161
Current liabilities - held for sale	5	72
Current liabilities - discontinued operations	72	846
Total current liabilities	2,398	3,354
Other Liabilities		
Long-term debt and capital leases	6,449	9,180
Nuclear decommissioning reserve	282	269
Nuclear decommissioning trust liability	371	415
Postretirement and other benefit obligations	435	458
Derivative instruments	304	143
Deferred income taxes	65	21
Out-of-market contracts, net	121	129
Other non-current liabilities	718	534
Non-current liabilities - held-for-sale	65	8
Non-current liabilities - discontinued operations	635	6,798
Total non-current liabilities	9,445	17,955
Total Liabilities	11,843	21,309
Redeemable noncontrolling interest in subsidiaries	19	78
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 420,288,886 and 418,323,134 shares issued; and 283,650,039 and 316,743,089 shares outstanding at December 31, 2018 and 2017	4	4
Additional paid-in capital	8,510	8,376
Accumulated deficit	(6,022)	(6,268)
Treasury stock, at cost; 136,638,847 and 101,580,045 shares at December 31, 2018 and 2017	(3,632)	(2,386)
Accumulated other comprehensive loss	(94)	(72)
Noncontrolling interest	—	2,314
Total Stockholders' Equity	(1,234)	1,968
Total Liabilities and Stockholders' Equity	$10,628	$23,355

See notes to Consolidated Financial Statements.

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

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Cash Flows from Operating Activities			
Net income/(loss)	$268	$(2,337)	$(891)
(Loss)/income from discontinued operations, net of income tax	(192)	(992)	65
Income/(loss) from continuing operations	460	(1,345)	(956)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	46	102	67
Depreciation, amortization and accretion	459	596	772
Provision for bad debts	85	68	45
Amortization of nuclear fuel	48	51	49
Amortization of financing costs and debt discount/premiums	29	29	33
Adjustment for debt extinguishment	44	49	142
Amortization of intangibles and out-of-market contracts	45	54	68
Amortization of unearned equity compensation	25	35	10
Net (gain)/loss on sale of assets and equity/cost method investments	(49)	(9)	139
Impairment losses	114	1,614	751
Changes in derivative instruments	37	(170)	16
Changes in deferred income taxes and liability for uncertain tax benefits	5	13	(12)
Changes in collateral deposits in support of risk management activities	(105)	(80)	396
Changes in nuclear decommissioning trust liability	60	11	41
GenOn settlement, net of insurance proceeds	(63)	—	—
Net loss on deconsolidation of Agua Caliente and Ivanpah projects	13	—	—
Cash provided/(used) by changes in other working capital, net of acquisition and disposition effects:			
Accounts receivable - trade	(83)	(83)	24
Inventory	31	143	60
Prepayments and other current assets	(41)	(187)	(120)
Accounts payable	113	44	(59)
Accrued expenses and other current liabilities	(166)	(88)	(61)
Other assets and liabilities	(104)	9	32
Cash provided by continuing operations	1,003	856	1,437
Cash provided by discontinued operations	374	754	471
Net Cash Provided by Operating Activities	1,377	1,610	1,908
Cash Flows from Investing Activities			
Acquisition of businesses, net of cash acquired	(243)	(14)	—
Capital expenditures	(388)	(254)	(544)
Proceeds from renewable energy grants	—	8	36
Net proceeds from sale/(purchases) of emission allowances	19	66	(1)
Investments in nuclear decommissioning trust fund securities	(572)	(512)	(551)
Proceeds from sales of nuclear decommissioning trust fund securities	513	501	510
Proceeds from sale of assets, net of cash disposed and sale of discontinued operations, net of fees	1,564	430	241
Deconsolidation of Agua Caliente and Ivanpah projects	(268)	—	—
Changes in investments in unconsolidated affiliates	(39)	(57)	(33)
Net (contributions to)/distributions from discontinued operations	(60)	150	(58)

Other	(6)	22	31
Cash provided/(used) by continuing operations	520	340	(369)
Cash used by discontinued operations	(725)	(979)	(388)
Net Cash Used by Investing Activities	(205)	(639)	(757)

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Cash Flows from Financing Activities			
Payments of dividends to preferred and common stockholders	(37)	(38)	(76)
Payments for treasury stock	(1,250)	—	—
Payments for preferred shares	—	—	(226)
Payments for debt extinguishment costs	(32)	(42)	(121)
Net distributions to noncontrolling interest from subsidiaries	(16)	(30)	(27)
Proceeds/(payments) from issuance of common stock	21	(2)	1
Proceeds from issuance of long-term debt	1,100	1,178	4,412
Payments of debt issuance costs	(19)	(18)	(61)
Payments for short and long-term debt	(1,734)	(1,884)	(5,146)
Receivable from affiliate	(26)	(125)	—
Other	(4)	(8)	(7)
Cash used by continuing operations	(1,997)	(969)	(1,251)
Cash provided/(used) by discontinued operations	471	(169)	483
Net Cash Used by Financing Activities	(1,526)	(1,138)	(768)
Effect of exchange rate changes on cash and cash equivalents	1	(1)	1
Change in Cash from discontinued operations	120	(394)	566
Net (Decrease)/Increase in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash	(473)	226	(182)
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period	1,086	860	1,042
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period	$613	$1,086	$860

See notes to Consolidated Financial Statements.

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

	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Loss	Noncon-trolling Interest	Total Stock-holders' Equity
	(In millions)						
Balances at December 31, 2015	$4	$ 8,296	$ (3,007)	$(2,413)	$ (173)	$2,727	5,434
Net loss			(774)			(79)	(853)
Other comprehensive income					38		38
Sale of assets to NRG Yield, Inc.		59				(16)	43
ESPP share purchases		(2)	(6)	14			6
Equity-based compensation		5	1				6
Common stock dividends			(74)				(74)
Dividend for preferred shares			(5)				(5)
Gain on redemption of preferred shares			78				78
Distributions to noncontrolling interests						(158)	(158)
Dividends paid to NRG Yield, Inc.						(92)	(92)
Contributions from noncontrolling interests						30	30
Redemption of noncontrolling interests						(7)	(7)
Balances at December 31, 2016	$4	$ 8,358	$ (3,787)	$(2,399)	$ (135)	$2,405	$ 4,446
Net loss			(2,153)			(98)	(2,251)
Other comprehensive income					51		51
Sale of assets to NRG Yield, Inc.		(25)				20	(5)
ESPP share purchases		(3)	(4)	13			6
Equity-based compensation		29					29
Common stock dividends			(38)				(38)
Distributions to noncontrolling interests						(65)	(65)
Dividends paid to NRG Yield, Inc.						(108)	(108)
Contributions from noncontrolling interests						160	160
Early adoption of new accounting standards		17	(286)		12		(257)
Balances at December 31, 2017	$4	$ 8,376	$ (6,268)	$(2,386)	$ (72)	$2,314	$ 1,968
Net income			268			26	294
Other comprehensive loss					(22)		(22)
Sale of assets to NRG Yield, Inc.		8				8	16
ESPP share purchases		(2)		4			2
Share repurchases				(1,250)			(1,250)
Equity-based compensation		27					27
Common stock dividends			(37)				(37)
Distributions to noncontrolling interests						(43)	(43)
Dividends paid to NRG Yield, Inc.						(61)	(61)
Contributions from noncontrolling interests						304	304
Adoption of new accounting standards			15				15
Sale of NRG Yield and other business						(2,548)	(2,548)
Equity component of convertible senior notes		101					101

Balances at December 31, 2018	$4	$ 8,510	$ (6,022)	$(3,632)	$ (94)	$—	$ (1,234)

See notes to Consolidated Financial Statements.

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NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 — Nature of Business
General
NRG Energy, Inc., or NRG or the Company, is an energy company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to consumers by producing, selling and delivering electricity and related products and services in major competitive power markets in the U.S. in a manner that delivers value to all of NRG's stakeholders. NRG is perfecting the integrated model by balancing retail load with generation supply within its deregulated markets, while evolving to a customer-driven business. The Company sells energy, services, and innovative, sustainable products and services directly to retail customers under the names "NRG" and "Reliant" and other brand names owned by NRG supported by approximately 23,000[(a)] MW of generation as of December 31, 2018.
Retail is a consumer facing business that includes residential and small commercial (Mass Market) consumers and the Company's Business Solutions group, which includes demand response, commodity sales, energy efficiency and energy management solutions. Products and services range from retail energy, portable solar and battery products home services, and a variety of bundled products, which combine energy with protection products, energy efficiency and renewable energy solutions, as well as other distributed and reliability products.
The Company's Generation business includes plant operations, commercial operations, EPC, asset management, energy services and other critical related functions. In addition to the traditional functions from NRG's wholesale power generation business, Generation also includes NRG's retained renewable generation business.
Discontinued Operations
On December 31, 2018, as described in Note 3, Acquisitions, Discontinued Operations and Dispositions, the Company concluded that the sale of its South Central Portfolio to Cleco, excluding the Cottonwood facility, met held-for-sale criteria and should be presented as a discontinued operation, as the sale represented a strategic shift in the business in which NRG operates. The financial information for all historical periods has been recast to reflect the presentation of these entities as discontinued operations.
On August 31, 2018, as described in Note 3, Acquisitions, Discontinued Operations and Dispositions, NRG deconsolidated NRG Yield, Inc. and its Renewables Platform for financial reporting purposes. The financial information for all historical periods has been recast to reflect the presentation of these entities, as well as the Carlsbad project, as discontinued operations. As a result of the sale of NRG Yield, the Company no longer controls the Agua Caliente project. Due to this change in control, the Company has deconsolidated the Agua Caliente project from its financial results and has accounted for the project as an equity method investment.
GenOn Chapter 11 Cases
On June 14, 2017, or the Petition Date, GenOn, along with GenOn Americas Generation and certain of their directly and indirectly-owned subsidiaries, or collectively the GenOn Entities, filed voluntary petitions for relief under Chapter 11, or the Chapter 11 Cases, of the U.S. Bankruptcy Code, or the Bankruptcy Code, in the U.S. Bankruptcy Court for the Southern District of Texas, Houston Division, or the Bankruptcy Court. GenOn Mid-Atlantic, as well as its consolidated subsidiaries, REMA and certain other subsidiaries, did not file for relief under Chapter 11. As a result of the bankruptcy filings and beginning on June 14, 2017, GenOn and its subsidiaries were deconsolidated from NRG's consolidated financial statements. NRG determined that this disposal of GenOn and its subsidiaries is a discontinued operation and, accordingly, the financial information for all historical periods has been recast to reflect GenOn as a discontinued operation. GenOn's plan of reorganization was confirmed on December 14, 2018.

(a) excluding discontinued operations and held for sale

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

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

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

Net Income/(Loss) attributable to NRG Energy, Inc.

The following table reflects the net income/(loss) attributable to NRG Energy, Inc. after removing the net loss attributable to the noncontrolling interest and redeemable noncontrolling interest:

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Income/(loss) from continuing operations, net of income tax	$465	$(977)	$(733)
Loss from discontinued operations, net of income tax	(197)	(1,176)	(41)
Net income/(loss) attributable to NRG Energy, Inc. stockholders	$268	$(2,153)	(774)

Segment Reporting

The Company's businesses are segregated into the Generation, Retail and corporate segments. Generation includes all power plant activities, domestic and international, as well as renewables. Retail includes Mass customers and Business Solutions, which includes C&I customers and other distributed and reliability products.

As described in Note 3, Acquisitions, Discontinued Operations and Dispositions, the Company has determined that the South Central Portfolio, NRG Yield Inc. and its Renewables Platform, Carlsbad, and GenOn all qualified for treatment as a discontinued operation. The financial information for all historical periods has been recast to reflect the presentation of discontinued operations within the corporate segment.

Cash and Cash Equivalents

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

Funds Deposited by Counterparties

Funds deposited by counterparties consist of cash held by the Company as a result of collateral posting obligations from its counterparties. Some amounts are segregated into separate accounts that are not contractually restricted but, based on the Company's intention, are not available for the payment of general corporate obligations. Depending on market fluctuations and the settlement of the underlying contracts, the Company will refund this collateral to the hedge counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company's balance sheet, with an offsetting liability for this cash collateral received within current liabilities. As of December 31, 2016, $79 million of the cash collateral received was from GenOn, previously a consolidated subsidiary, and is included in cash collateral received in current liabilities as a result of deconsolidating GenOn, with the offset included in cash and cash equivalents.

Restricted Cash

The following table provides a reconciliation of cash and cash equivalents, restricted cash and funds deposited by counterparties reported within the consolidated balance sheets that sum to the total of the same such amounts shown in the statements of cash flows.

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Cash and cash equivalents	$563	$770	$591
Funds deposited by counterparties	33	37	2
Restricted cash	17	279	267
Cash and cash equivalents, funds deposited by counterparties and restricted cash shown in the statements of cash flows	$613	$1,086	$860

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within the Company's projects that are restricted in their use.

Trade Receivables and Allowance for Doubtful Accounts

Trade receivables are reported in the balance sheet at outstanding principal adjusted for any write-offs and the allowance for doubtful accounts. For its retail business, the Company accrues an allowance for doubtful accounts based on estimates of uncollectible revenues by analyzing counterparty credit ratings (for commercial and industrial customers), historical collections, accounts receivable aging and other factors. The retail business writes-off accounts receivable balances against the allowance for doubtful accounts when it determines a receivable is uncollectible. In addition, the Company considers a reserve for doubtful accounts based on the credit worthiness of the customers and continually reviews and adjusts for current economic trends that might impact the level of future credit losses. The reserve represents management's best estimate of uncollectible amounts. As of December 31, 2018 and 2017, the allowance for doubtful accounts was $32 million and $28 million, respectively.

Inventory

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

Property, Plant and Equipment

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

Asset Impairments

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

Investments accounted for by the equity method are reviewed for impairment in accordance with ASC 323, Investments-Equity Method and Joint Ventures, or ASC 323, which requires that a loss in value of an investment that is an other-than-temporary decline should be recognized. The Company identifies and measures losses in the value of equity method investments based upon a comparison of fair value to carrying value. For further discussion of these matters, refer to Note 9, Asset Impairments.

Development Costs and Capitalized Interest

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

Interest incurred on funds borrowed to finance capital projects is capitalized until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2018, 2017, and 2016, was $7 million, $20 million, and $29 million, respectively.

Debt Issuance Costs

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

Intangible Assets

Intangible assets represent contractual rights held by the Company. The Company recognizes specifically identifiable intangible assets including customer contracts, customer relationships, energy supply contracts, marketing partnerships, power purchase agreements, trade names, emission allowances, and fuel contracts when specific rights and contracts are acquired. These intangible assets are amortized based on expected volumes, expected delivery, expected discounted future net cash flows, straight line or units of production basis. As of December 31, 2018 and 2017, the Company had accumulated amortization related to its intangible assets of $1.2 billion and $1.6 billion, respectively.

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

Goodwill

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

The Company first assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The more-likely-than-not threshold is defined as having a likelihood of more than 50 percent. If it is not more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, there is no goodwill impairment.

In the absence of sufficient qualitative factors, the Company performs a quantitative assessment by determining the fair value of the reporting unit and comparing the fair value to its book value. If the fair value of the reporting unit exceeds its book value, goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, the Company recognizes an impairment loss equal to the difference between book value and fair value.

For further discussion of goodwill and goodwill impairment losses recognized refer to Note 10, Goodwill and Other Intangibles.

Income Taxes

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

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

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

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

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

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

In accordance with ASC 805 and as discussed further in Note 18, Income Taxes, changes to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, are recorded to income tax expense.

Revenue Recognition

Revenue from Contracts with Customers

On January 1, 2018, the Company adopted the guidance in ASC 606 using the modified retrospective method applied to contracts that were not completed as of the adoption date. The Company recognized the cumulative effect of initially applying the new standard as a credit to the opening balance of accumulated deficit, resulting in a decrease of approximately $15 million. The adjustment primarily related to costs incurred to obtain a contract with customers and customer incentives. Following the adoption of the new standard, the Company’s revenue recognition of its contracts with customers remains materially consistent with its historical practice. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The Company's policies with respect to its various revenue streams are detailed below. In general, the Company applies the invoicing practical expedient to recognize revenue for the revenue streams detailed below, except in circumstances where the invoiced amount does not represent the value transferred to the customer.

Retail Revenues

Gross revenues for energy sales and services to retail customers are recognized as the Company transfers the promised goods and services to the customer. For the majority of its electricity contracts, the Company’s performance obligation with the customer is satisfied over time and performance obligations for its electricity products are recognized as the customer takes possession of the product. The Company also allocates the contract consideration to distinct performance obligation in a contract for which the timing of the revenue recognized is different. Additionally, customer discounts and incentives reduce the contract consideration and are recognized over the term of the contract. Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

As contracts for retail electricity can be for multi-year periods, the Company has performance obligations under these contracts that have not yet been satisfied. These performance obligations have transaction prices that are both fixed and variable, and that vary based on the contract duration, customer type, inception date and other contract-specific factors. For the fixed price contracts, the amount of any unsatisfied performance obligations will vary based on customer usage, which will depend on factors such as weather and customer activity and therefore it is not practicable to estimate such amounts.

Energy Revenue

Both physical and financial transactions are entered into to optimize the financial performance of the Company's generating facilities. Electric energy revenue is recognized upon transmission to the customer over time, using the output method for measuring progress of satisfaction of performance obligations. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in the Company's consolidated statements of operations. The Company applies the invoicing practical expedient, where applicable, in recognizing energy revenue. Under the practical expedient, revenue is recognized based on the invoiced amount which is equal to the value to the customer of NRG’s performance obligation completed to date. Financial transactions, or the buying and selling of energy for trading purposes, are recorded net within operating revenues in the consolidated statements of operations in accordance with ASC 815.

Capacity Revenue

Capacity revenues consist of revenues billed to a third party at either the market or a negotiated contract price for making installed generation and demand response capacity available in order to satisfy system integrity and reliability requirements. Capacity revenues are recognized over time, using the output method for measuring progress of satisfaction of performance obligations. The Company applies the invoicing practical expedient, where applicable, in recognizing capacity revenue. Under the practical expedient, revenue is recognized based on the invoiced amount which is equal to the value to the customer of NRG’s performance obligation completed to date.

Capacity revenue contracts mainly consist of:

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. In addition, MISO has an annual auction, known as the Planning Resource Auction, or PRA. As of December 31, 2018, estimated future revenues for cleared auction MWs in the various capacity auctions are $618 million, $481 million, $532 million, and $244 million for fiscal years 2019, 2020, 2021 and 2022, respectively.

Resource adequacy and bilateral contracts — In California, there is a resource adequacy requirement that is primarily satisfied through bilateral contracts. Such bilateral contracts are typically short-term resource adequacy contracts. When bilateral contracting does not satisfy the resource adequacy need, such shortfalls can be addressed through procurement tools administered by the CAISO, including the capacity procurement mechanism or reliability must-run contracts. 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 and New York, capacity and contracted revenues are through bilateral contracts with third parties of our Retail segment.

Renewable Energy Credits

Renewable energy credits are usually sold through long-term contracts. Revenue from the sale of self-generated RECs is recognized when related energy is generated and simultaneously delivered even in cases where there is a certification lag as it has been deemed to be perfunctory.

In a bundled contract to sell energy, capacity and/or self-generated RECs, all performance obligations are deemed to be delivered at the same time and hence, timing of recognition of revenue for all performance obligations is the same and occurs over time. In such cases, it is often unnecessary to allocate transaction price to multiple performance obligations.

Sale of Emission Allowances

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

Disaggregated Revenues

The following table represents the Company's disaggregation of revenue from contracts with customers for the year ended December 31, 2018, along with the reportable segment for each category:

	For the Year Ended December 31, 2018					
		Generation				
(In millions)	Retail	Texas	East/West/Other	Subtotal	Corporate/Eliminations	Total
Energy revenue[(a)]	$—	$1,585	$ 1,092	$2,677	$ (1,129)	$1,548
Capacity revenue[(a)]	—	1	669	670	—	670
Retail revenue						
Mass customers	5,618	—	—	—	(5)	5,613
Business Solutions customers	1,492	—	—	—	—	1,492
Total retail revenue	7,110	—	—	—	(5)	7,105
Mark-to-market for economic hedging activities[(b)]	(7)	(174)	(28)	(202)	79	(130)
Other revenue[(a)(c)]	—	84	203	287	(2)	285
Total operating revenue	7,103	1,496	1,936	3,432	(1,057)	9,478
Less: Lease revenue	13	—	8	8	—	21
Less: Derivative revenue	(7)	2,160	193	2,353	(1,037)	1,309
Total revenue from contracts with customers	$7,097	$(664)	$ 1,735	$1,071	$ (20)	$8,148

(a) The following amounts of energy, capacity and other revenue relate to derivative instruments and are accounted for under ASC 815:

	Retail	Texas	East/West/Other	Subtotal	Corporate/Eliminations	Total
Energy revenue	$—	$2,332	$ 69	$2,401	$ (1,117)	$1,284
Capacity revenue	—	—	138	138	—	138
Other revenue	—	2	14	16	—	16

(b) Revenue relates entirely to unrealized gains and losses on derivative instruments accounted for under ASC 815

(c) Included in other revenue is lease revenue of $17 million and $5 million for Retail and East/West/Other, respectively

Contract Amortization

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

Lease Revenue

Certain of the Company's revenues are obtained through leases of rooftop residential solar systems, which are accounted for as operating leases in accordance with ASC 840, Leases. Pursuant to the lease agreements, the customers' monthly payments are pre-determined fixed monthly amounts and may include an annual fixed percentage escalation to reflect the impact of utility rate increases over the lease term, which is 20 years. The Company records operating lease revenue on a straight-line basis over the life of the lease term. Certain customers made initial down payments that are being amortized over the life of the lease. The difference between the payments received and the revenue recognized is recorded as deferred revenue.

Contract Balances
The following table reflects the contract assets and liabilities included in the Company's balance sheet as of December 31, 2018:

	(In millions)
Deferred customer acquisition costs	$ 111
Accounts receivable, net - Contracts with customers	1,002
Accounts receivable, net - Derivative instruments	20
Total accounts receivable, net	$ 1,022
Unbilled revenues (included within Accounts receivable, net - Contracts with customers)	$ 392
Deferred revenues	$ 67

The Company's customer acquisition costs consist of broker fees, commission payments and other costs that represent incremental costs of obtaining the contract with customers for which the Company expects to recover. The Company amortizes these amounts over the estimated life of the customer contract. As a practical expedient, the Company expenses the incremental costs of obtaining a contract if the amortization period of the asset would have been one year or less.
When the Company receives consideration from the customer that is in excess of the amount due, such consideration is reclassified to deferred revenue, which represents a contract liability. Generally, the Company will recognize revenue from contract liabilities in the next period as the Company satisfies its performance obligations.
Lessor Accounting
Certain of the Company's revenues are obtained through PPAs or other contractual agreements. Many of these agreements are accounted for as operating leases under ASC 840 Leases.
Certain of these leases have no minimum lease payments and all of the rent is recorded as contingent rent on an actual basis when the electricity is delivered. Judgment is required by management in determining the economic life of each generating facility, in evaluating whether certain lease provisions constitute minimum payments or represent contingent rent and other factors in determining whether a contract contains a lease and whether the lease is an operating lease or capital lease. Contingent rental income recognized in the years ended December 31, 2018, 2017, and 2016 was $104 million, $253 million, and $272 million, respectively.
Gross Receipts and Sales Taxes
In connection with its retail business, the Company records gross receipts taxes on a gross basis in revenues and cost of operations in its consolidated statements of operations. During the years ended December 31, 2018, 2017, and 2016, the Company's revenues and cost of operations included gross receipts taxes of $99 million, $92 million, and $101 million, respectively. Additionally, the retail business records sales taxes collected from its taxable customers and remitted to the various governmental entities on a net basis; thus, there is no impact on the Company's consolidated statement of operations.
Cost of Energy for Retail Operations
The cost of energy for electricity sales and services to retail customers is included in cost of operations and is based on estimated supply volumes for the applicable reporting period. A portion of the cost of energy $105 million, $107 million, and $90 million as of December 31, 2018, 2017, and 2016, respectively, was accrued and consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities. In estimating supply volumes, the Company considers the effects of historical customer volumes, weather factors and usage by customer class. Transmission and distribution delivery fees are estimated using the same method used for electricity sales and services to retail customers. In addition, ISO fees are estimated based on historical trends, estimated supply volumes and initial ERCOT ISO settlements. Volume estimates are then multiplied by the supply rate and recorded as cost of operations in the applicable reporting period.

Derivative Financial Instruments

The Company accounts for derivative financial instruments under ASC 815, which requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a NPNS exception. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as cash flow hedges, if elected for hedge accounting, are deferred and recorded as a component of accumulated OCI until the hedged transactions occur and are recognized in earnings.

The Company's primary derivative instruments are power purchase or sales contracts, fuels purchase contracts, other energy related commodities, and interest rate instruments used to mitigate variability in earnings due to fluctuations in market prices and interest rates. On an ongoing basis, the Company assesses the effectiveness of all derivatives that are designated as hedges for accounting purposes in order to determine that each derivative continues to be highly effective in offsetting changes in fair values or cash flows of hedged items. Internal analyses that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such a contract designated as a hedge. If it is determined that the derivative instrument is not highly effective as a hedge, hedge accounting will be discontinued prospectively. In this case, the gain or loss previously deferred in accumulated OCI would be frozen until the underlying hedged instrument is delivered unless the transactions being hedged are no longer probable of occurring in which case the amount in OCI would be immediately reclassified into earnings. If the derivative instrument is terminated, the effective portion of this derivative deferred in accumulated OCI will be frozen until the underlying hedged item is delivered.

Revenues and expenses on contracts that qualify for the NPNS exception are recognized when the underlying physical transaction is delivered. While these contracts are considered derivative financial instruments under ASC 815, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception, the fair value of the related contract is recorded on the balance sheet and immediately recognized through earnings.

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

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG's foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the Company's consolidated statements of operations for the period, but are accumulated and reported as a separate component of stockholders' equity until sale or complete or substantially complete liquidation of the net investment in the foreign entity takes place. Foreign currency transaction gains or losses are reported within other income/(expense) in the Company's consolidated statements of operations. For the years ended December 31, 2018, 2017, and 2016, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2018, 2017, and 2016 were $(13) million, $(2) million and $(11) million, respectively.

Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trust funds, accounts receivable, notes receivable, derivatives, and investments in debt securities. Trust funds are held in accounts managed by experienced investment advisors. Certain accounts receivable, notes receivable, and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables and other contractual arrangements are subject to collateral requirements under the terms of enabling agreements. However, the Company believes that the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its customer base. See Note 4, Fair Value of Financial Instruments, for a further discussion of derivative concentrations.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, funds deposited by counterparties, receivables, accounts payable, and accrued liabilities approximate fair value because of the short-term maturity of these instruments. See Note 4, Fair

Value of Financial Instruments, for a further discussion of fair value of financial instruments.

Asset Retirement Obligations

The Company accounts for AROs in accordance with ASC 410-20, Asset Retirement Obligations, or ASC 410-20. Retirement obligations associated with long-lived assets included within the scope of ASC 410-20 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. ASC 410-20 requires an entity to recognize the fair value of a liability for an ARO in the period in which it is incurred and a reasonable estimate of fair value can be made.

Upon initial recognition of a liability for an ARO, the Company capitalizes the asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount. Over time, the liability is accreted to its future value, while the capitalized cost is depreciated over the useful life of the related asset. See Note 12 , Asset Retirement Obligations, for a further discussion of AROs.

Pensions and Other Postretirement Benefits

The Company offers pension benefits through a defined benefit pension plan. In addition, the Company provides postretirement health and welfare benefits for certain groups of employees. The Company accounts for pension and other postretirement benefits in accordance with ASC 715, Compensation — Retirement Benefits. The Company recognizes the funded status of the Company's defined benefit plans in the statement of financial position and records an offset for gains and losses as well as all prior service costs that have not been included as part of the Company's net periodic benefit cost to other comprehensive income. The determination of the Company's obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. The Company's actuarial consultants assist in determining assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by the Company.

The Company measures the fair value of its pension assets in accordance with ASC 820, Fair Value Measurements and Disclosures, or ASC 820.

Stock-Based Compensation

The Company accounts for its stock-based compensation in accordance with ASC 718, Compensation — Stock Compensation, or ASC 718. The fair value of the Company's non-qualified stock options and market stock units are estimated on the date of grant using the Black-Scholes option-pricing model and the Monte Carlo valuation model, respectively. NRG uses the Company's common stock price on the date of grant as the fair value of the Company's restricted stock units and deferred stock units. Forfeiture rates are estimated based on an analysis of the Company's historical forfeitures, employment turnover, and expected future behavior. The Company recognizes compensation expense for both graded and cliff vesting awards on a straight-line basis over the requisite service period for the entire award.

Investments Accounted for by the Equity Method

The Company has investments in various domestic energy projects, as well as one Australian project. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents the Company from exercising a controlling influence over the operating and financial policies of the projects. Under this method, equity in pre-tax income or losses of domestic partnerships and, generally, in the net income or losses of its Australian project, are reflected as equity in earnings of unconsolidated affiliates. Distributions from equity method investments that represent earnings on the Company's investment are included within cash flows from operating activities and distributions from equity method investments that represent a return of the Company's investment are included within cash flows from investing activities.

Tax Equity Arrangements

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

Redeemable Noncontrolling Interest

To the extent that the third-party has the right to redeem their interests for cash or other assets, the Company has included the noncontrolling interest attributable to the third party as a component of temporary equity in the mezzanine section of the consolidated balance sheet. The following table reflects the changes in the Company's redeemable noncontrolling interest balance for the years ended December 31, 2018, 2017, and 2016.

	(In millions)		
Balance as of December 31, 2015	$	29	
Distributions to redeemable noncontrolling interest	(1		)
Contributions from redeemable noncontrolling interest	33		
Non-cash adjustments to redeemable noncontrolling interest	23		
Comprehensive loss attributable to redeemable noncontrolling interest	(38		)
Balance as of December 31, 2016	46		
Distributions to redeemable noncontrolling interest	(2		)
Contributions from redeemable noncontrolling interest	99		
Non-cash adjustments to redeemable noncontrolling interest	7		
Comprehensive loss attributable to redeemable noncontrolling interest	(72		)
Balance as of December 31, 2017	78		
	(3		)

Distributions to redeemable noncontrolling interest		
Contributions from redeemable noncontrolling interest	26	
Non-cash adjustments to redeemable noncontrolling interest	(8	)
Net income attributable to redeemable noncontrolling interest - continuing operations	1	
Net loss attributable to redeemable noncontrolling interest - discontinued operations	(27	)
Sale of NRG Yield and the Renewables Platform[(a)]	(48	)
Balance as of December 31, 2018	$ 19	

(a) See Note 3, Acquisitions, Discontinued Operations and Dispositions, for further information regarding the sale of NRG Yield and its Renewables Platform

Sale-Leaseback Arrangements

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

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

As described in Note 3, Acquisitions, Discontinued Operations and Dispositions, the Company entered into an agreement to leaseback the Cottonwood facility upon the close of the South Central Portfolio transaction. The lease will be accounted for as an operating lease and accordingly, a right of use asset and lease liability will be set up on the lease commencement date which will be amortized through the end of the lease.

Marketing and Advertising Costs

The Company expenses its marketing and advertising costs as incurred and which are included within selling, general and administrative expenses. The costs of tangible assets used in advertising campaigns are recorded as fixed assets or deferred advertising costs and amortized as advertising costs over the shorter of the useful life of the asset or the advertising campaign. The Company has several long-term sponsorship arrangements. Payments related to these arrangements are deferred and expensed over the term of the arrangement. Advertising expenses for the years ended December 31, 2018, 2017, and 2016 were $73 million, $66 million, and $79 million, respectively.

Reorganization Costs

Reorganization costs include costs incurred by the Company related to the Transformation Plan implementation and primarily reflect severance and contract modifications. As of December 31, 2018 and December 31, 2017, $90 million and $44 million were incurred.

Business Combinations

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

Use of Estimates

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

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

Reclassifications

Certain prior year amounts have been reclassified for comparative purposes. The reclassifications did not affect results from operations, net assets or cash flows.

Recent Accounting Developments - Guidance Adopted in 2018

ASU 2017-07 — In March 2017, the FASB issued ASU No. 2017-07, Compensation - Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, or ASU No. 2017-07. Previous GAAP does not indicate where the amount of net benefit cost should be presented in an entity's income statement and does not require entities to disclose the amount of net benefit cost that is included in the income statement. The amendments of ASU No. 2017-07 require an entity to report the service cost component of net benefit costs in the same line item as other compensation costs arising from services rendered by the related employees during the applicable service period. The other components of net benefit cost are required to be presented separately from the service cost component and outside the subtotal of income from operations. Further, ASU No. 2017-07 prescribes that only the service cost component of net benefit costs is eligible for capitalization. The Company adopted the amendments of ASU No. 2017-07 effective January 1, 2018. The adoption of ASU No. 2017-07 did not have a material impact on the Company's results of operations, cash flows, and statement of financial position.

ASU 2016-01 - In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, or ASU No. 2016-01. The amendments of ASU No. 2016-01 eliminate available-for-sale classification of equity investments and require that equity investments (except those accounted for under the equity method of accounting, or those that result in consolidation of the investee) be generally measured at fair value with changes in fair value recognized in net income. Further, the amendments require that financial assets and financial liabilities be presented separately in the notes to the financial statements, grouped by measurement category and form of financial asset. The guidance in ASU No. 2016-01 is effective for financial statements issued for fiscal years beginning after December 15, 2017, and interim periods within those annual periods. The Company adopted the amendments of ASU No. 2016-01 effective January 1, 2018. In connection with the adoption of the standard, the Company has applied the guidance on a modified retrospective basis, which resulted in no material adjustments recorded to the consolidated results of operations, cash flows, and statement of financial position.

ASU 2014-09 — In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), or Topic 606, which was further amended through various updates issued by the FASB thereafter. The amendments of Topic 606 completed the joint effort between the FASB and the IASB, to develop a common revenue standard for GAAP and IFRS, and to improve financial reporting. The guidance under Topic 606 provides that an entity should recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for the goods or services provided and establishes a five-step model to be applied by an entity in evaluating its contracts with customers. The Company has also elected the practical expedient available under Topic 606 for measuring progress toward complete satisfaction of a performance obligation and for disclosure requirements of remaining performance obligations. The practical expedient allows an entity to recognize revenue in the amount to which the entity has the right to invoice such that the entity has a right to the consideration in an amount that corresponds directly with the value to the customer for performance completed to date by the entity. The Company adopted the standard effective January 1, 2018. The adoption of Topic 606 at the date of initial application, as prescribed under the modified retrospective transition method, did not have a material impact on the Company's financial statements. The adoption of Topic 606 also includes additional disclosure requirements beginning in the first quarter of 2018. Many of these disclosures are not substantially different than the Company's existing disclosures. Topic 606 requires disclosure of disaggregated revenue amounts, which the Company has been disclosing since the date of adoption.

Recent Accounting Developments - Guidance Not Yet Adopted

ASU 2018-17 - In October 2018, the FASB issued ASU No. 2018-17, Consolidations (Topic 810): Targeted Improvements to Related Party Guidance for Variable Interest Entities, in response to stakeholders' observations that Topic 810, Consolidations, could be improved thereby improving general purpose financial reporting. Specifically, ASC 2018-17 requires application of the variable interest entity (VIE) guidance to private companies under common control and consideration of indirect interest held through related parties under common control for determining whether fees paid to decision makers and service providers are variable interests. The amendments are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. All entities are required to apply the amendments retrospectively with a cumulative-effect adjustment to retained earnings at the beginning of the earliest period presented. The Company is evaluating the impact of adopting this guidance on the consolidated financial statements and disclosures.

ASU 2018-13 - In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirement for Fair value Measurement), or ASU No. 2018-13. The guidance in ASU No. 2018-13 eliminates such disclosures as the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy. The amendments in ASU No. 2018-13 add new disclosure requirements for Level 3 measurements. ASU No. 2018-13 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted for any eliminated or modified disclosures. Certain disclosures in ASU No. 2018-13 are required to be applied on a retrospective basis and others on a prospective basis. As the amendment contemplates changes in disclosures only, it will have no material impact on the Company's results of operations, cash flows, or statement of financial position.

ASU 2016-02 - In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), or Topic 842, with the objective to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and to improve financial reporting by expanding the related disclosures. The guidance in Topic 842 provides that a lessee that may have previously accounted for a lease as an operating lease under current GAAP should recognize the assets and liabilities that arise from a lease on the balance sheet. In addition, Topic 842 expands the required quantitative and qualitative disclosures with regards to lease arrangements. The Company adopted the standard and its subsequent corresponding updates effective January 1, 2019 under the modified retrospective approach by applying the provisions of the new leases guidance at the effective date without adjusting the comparative periods presented. The Company has assessed its leasing arrangements and evaluated the impact of applying practical expedients and accounting policy elections. The Company implemented lease accounting software to meet the reporting requirements of the standard and identified changes to its business processes and controls to support recognition and disclosure under the new standard. Management estimates operating lease liabilities will increase between $380 million and $420 million and right-of-use assets between $300 million and $340 million will be established upon adoption, before considering deferred taxes. Management does not believe the adoption of Topic 842 will have a material impact on the statements of operations or cash flows.

Note 3 — Acquisitions, Discontinued Operations and Dispositions

Acquisitions

XOOM Energy Acquisition — On June 1, 2018, the Company completed the acquisition of XOOM Energy, LLC, an electricity and natural gas retailer operating in 19 states, Washington, D.C. and Canada, for approximately $213 million in cash. The acquisition increased NRG's retail portfolio by approximately 300,000 customers. The purchase price was allocated as follows:

	(In millions)
Net current and non-current working capital	$ 46
Other intangible assets	133
Goodwill	34
XOOM Purchase Price	$ 213

Small Book Acquisitions — Through the end of December 2018, the Company has agreed to acquire several books of customers totaling approximately 115,000 customers, along with brand names, for $44 million, the majority of which was allocated to acquired intangibles.

Discontinued Operations

Sale of South Central Portfolio

On February 4, 2019, the Company completed the sale of its South Central Portfolio to Cleco. The Company concluded that the divested business met the criteria for discontinued operations, as the disposition represents a strategic shift in the business in which NRG operates and held-for-sale criteria as of December 31, 2018. As such, all prior period results for the operations of the South Central Portfolio have been reclassified as discontinued operations. In connection with the transaction, NRG also entered into a transition services agreement to provide certain corporate services to the divested business.

The South Central Portfolio includes the 1,263 MW Cottonwood natural gas generating facility. Upon the closing of the sale of the South Central Portfolio, NRG entered into a lease agreement with Cleco to leaseback the Cottonwood facility through 2025. Due to its continuing involvement with the Cottonwood facility, NRG will not use held-for-sale or discontinued operations treatment in accounting for historical and ongoing activity with Cottonwood.

Summarized results of South Central discontinued operations were as follows:

(In millions)	Year Ended December 31, 2018	2017	2016
Operating revenues	$410	$422	$467
Operating costs and expenses	(346)	(335)	(395)
Other income	2	—	—
Gain from discontinued operations, net of tax	$66	$87	$72

The following table summarizes the major classes of assets and liabilities classified as discontinued operations of South Central as follows:

(In millions)	December 31, 2018	December 31, 2017
Cash and cash equivalents	$ 89	$ (3)
Accounts receivable, net	49	61
Inventory	35	33
Other current assets	5	—
Current assets - discontinued operations	178	91
Property, plant and equipment, net	408	461
Other non-current assets	1	1
Non-current assets - discontinued operations	409	462
Accounts payable	19	28
Other current liabilities	5	6
Current liabilities - discontinued operations	24	34
Out-of-market contracts, net	50	66
Other non-current liabilities	11	10
Non-current liabilities - discontinued operations	$ 61	$ 76

Sale of Ownership in NRG Yield, Inc. and its Renewables Platform

On August 31, 2018, the Company completed the sale of its ownership interests in NRG Yield, Inc. and its Renewables Platform to GIP for total cash consideration of $1.348 billion. The Company concluded that the divested businesses met the criteria for discontinued operations, as the dispositions represented a strategic shift in the business in which NRG operates. As such, all prior period results for the transaction have been reclassified as discontinued operations. In connection with the transaction, NRG entered into a transition services agreement to provide certain corporate services to the divested businesses.

As a result of the sale of NRG Yield, Inc., the Company's indirect ownership interest in the Agua Caliente solar project was reduced from 51% to 35%. As such, the Company no longer controls the project; and accordingly, no longer consolidates the project for financial reporting purposes. The Company recorded its ownership interest as an equity method investment upon deconsolidation resulting in a gain of $8 million.

As part of the agreement to sell NRG Yield and the Renewables Platform, the Company agreed to indemnify NRG Yield for any increase in property taxes for certain solar properties. The indemnity term will expire at various dates between 2029 and 2039. NRG has determined that the payment of this indemnity is probable and has recorded the estimated present value of the obligation as of the closing date of the transaction of $153 million to other non-current liabilities with a corresponding loss from discontinued operations. In addition to the California property tax indemnity, there were additional commitments and advisory fees totaling approximately $50 million. The Company will also retain all costs associated with the development and ownership of the Patriot Wind project until its sale to a third party pursuant to a sale agreement.

Carlsbad

On February 6, 2018, NRG entered into an agreement with NRG Yield and GIP to sell 100% of the membership interests in Carlsbad Energy Holdings LLC, which owned the Carlsbad project, for $387 million of cash consideration, excluding working capital adjustments. The primary condition to close the Carlsbad transaction was the completion of the sale of NRG Yield and the Renewables Platform. As the sale of NRG Yield and the Renewables Platform has closed, the Company concluded that the Carlsbad project met the criteria for discontinued operations and accordingly, the financial information for all current and historical periods has been recast to reflect Carlsbad as a discontinued operation. The Company continued to consolidate Carlsbad for financial reporting purposes until the transaction closed on February 27, 2019. Carlsbad will continue to have a ground lease and easement agreement with NRG. The agreement has an initial term ending in 2039 with two ten year extensions. As a result of the transaction, additional commitments related to the project totaled $23 million.

Summarized results of NRG Yield, Inc. and Renewables Platform and Carlsbad discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	2018	2017	2016
Operating revenues	$909	$1,164	$1,165
Operating costs and expenses	(661)	(1,114)	(1,023)
Other expenses	(174)	(288)	(261)
Gain/(loss) from operations of discontinued components, before tax	74	(238)	(119)
Income tax expense/(benefit)	4	52	(20)
Gain/(loss) from discontinued operations, net of tax	70	(290)	(99)
Loss on deconsolidation, net of tax	(134)	—	—
California property tax indemnification	(153)	—	—
Other Commitments, Indemnification and Fees	(75)	—	—
Loss on disposal of discontinued operations, net of tax	(362)	—	—
Loss from discontinued operations, net of tax	$(292)	$(290)	$(99)

The following table summarizes the major classes of assets and liabilities classified as discontinued operations as follows:

(In millions)	December 31, 2018 (a)	December 31, 2017 (b)
Cash and cash equivalents	$ —	$ 224
Restricted Cash	4	229
Accounts receivable, net	10	119
Other current assets	5	81
Current assets - discontinued operations	19	653
Property, plant and equipment, net	590	7,473
Equity investments in affiliates	—	856
Intangible assets, net	9	1,240
Other non-current assets	4	475
Non-current assets - discontinued operations	603	10,044
Current portion of long term debt and capital leases	20	484
Accounts payable	27	169
Other current liabilities	1	159
Current liabilities - discontinued operations	48	812
Long-term debt and capital leases	572	6,536
Other non-current liabilities	2	186
Non-current liabilities - discontinued operations	$ 574	$ 6,722

(a) Represents the Carlsbad project
(b) Represents the discontinued operations of NRG Yield, NRG's Renewable Platform and the Carlsbad project

Sale of Assets to NRG Yield, Inc. Prior to Discontinued Operations
On June 19, 2018, the Company completed the UPMC Thermal Project and received cash consideration from NRG Yield of $84 million plus an additional $3 million received at final completion in January 2019.
On March 30, 2018, as part of the Transformation Plan, the Company sold to NRG Yield, Inc. 100% of NRG's interests in Buckthorn Renewables, LLC, which owns a 154 MW construction-stage utility-scale solar generation project, located in Texas. NRG Yield, Inc. paid cash consideration of approximately $42 million, excluding working capital adjustments, and assumed non-recourse debt of approximately $183 million.
On March 27, 2017, the Company sold to NRG Yield, Inc.: (i) a 16% interest in the Agua Caliente solar project, representing ownership of approximately 46 net MW of capacity and (ii) NRG's interests in seven utility-scale solar projects located in Utah representing 265 net MW of capacity, which have reached commercial operations. NRG Yield, Inc. paid cash consideration of $130 million, plus $1 million in working capital adjustments, and assumed non-recourse debt of approximately $328 million.
On September 1, 2016, the Company completed the sale of its remaining 51.05% interest in the CVSR project to NRG Yield, Inc. for total cash consideration of $78.5 million, plus an immaterial working capital adjustment. In addition, NRG Yield, Inc. assumed non-recourse project level debt of $496 million.
GenOn
On June 14, 2017, the GenOn Entities filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. As a result of the bankruptcy filings, NRG concluded that it no longer controlled GenOn as it was subject to the control of the Bankruptcy Court; and, accordingly, NRG deconsolidated GenOn and its subsidiaries for financial reporting purposes as of such date.
By eliminating a large portion of its operations in the PJM market with the deconsolidation of GenOn, NRG concluded that GenOn met the criteria for discontinued operations, as this represented a strategic shift in the business in which NRG operated. As such, all prior period results for GenOn have been reclassified as discontinued operations.

Summarized results of discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	2018	2017	2016
Operating revenues	$—	$646	$1,862
Operating costs and expenses	—	(702)	(1,896)
Gain on sale of assets	—	—	294
Other expenses	—	(98)	(168)
(Loss)/gain from operations of discontinued components, before tax	—	(154)	92
Income tax expense	—	9	11
(Loss)/gain from discontinued operations	—	(163)	81
Interest income - affiliate	3	8	11
Income/(loss) from discontinued operations, net of tax	3	(155)	92
Pre-tax loss on deconsolidation	—	(208)	—
Settlement consideration, insurance and services credit	63	(289)	—
Pension and post-retirement liability assumption	21	(131)	—
Other	(53)	(6)	—
Income/(loss) on disposal of discontinued operations, net of tax	31	(634)	—
Income/(loss) from discontinued operations, net of tax	$34	$(789)	$92

GenOn Settlement and Plan Confirmation

Effective July 16, 2018, NRG and GenOn consummated the GenOn Settlement whereby the Company paid GenOn approximately $125 million, which included (i) the settlement consideration of $261 million, (ii) the transition services credit of $28 million and (iii) the return of $15 million of collateral posted to NRG; offset by the (i) $151 million in borrowings under the intercompany secured revolving credit facility, (ii) related accrued interest and fees of $12 million, (iii) remaining payments due under the transition services agreement of $10 million, (iv) $4 million reduction of the settlement payment related to NRG assigning to GenOn approximately $8 million of historical claims against REMA and (v) certain other balances due to NRG totaling $2 million.

GenOn's plan of reorganization was confirmed on December 14, 2018. Pursuant to the confirmed plan, NRG retained the pension liability for GenOn employees for service provided prior to the completion of the reorganization. NRG also retained the liability for GenOn's post-employment and retiree health and welfare benefits. These liabilities were recorded within other non-current liabilities as of December 31, 2018 and 2017. As a result of GenOn's emergence from bankruptcy, NRG is taking a deduction for GenOn tax losses of $9.5 billion, including a worthless stock deduction.

Other than those obligations which survive or are independent of the releases described herein, the GenOn Settlement and the GenOn Chapter 11 plan provide NRG releases from GenOn and each of its debtor and non-debtor subsidiaries.

REMA Plan of Reorganization

On October 16, 2018, REMA and its subsidiaries filed voluntary petitions for chapter 11 relief and a prepackaged plan of reorganization in the United States Bankruptcy Court for the Southern District of Texas. The REMA debtors' plan of reorganization has been formally accepted by REMA's voting creditors and is consistent with the releases NRG received under the GenOn Settlement and the GenOn plan.

GenMA Settlement

The Bankruptcy Court order confirming the plan of reorganization also approved the settlement terms agreed to among the GenOn Entities, NRG, the Consenting Holders, GenOn Mid-Atlantic, and certain of GenOn Mid-Atlantic's stakeholders, or the GenMA Settlement, and directed the settlement parties to cooperate in good faith to negotiate definitive documentation consistent with the GenMA Settlement term sheet in order to pursue consummation of the GenMA Settlement. The definitive documentation effectuating the GenMA Settlement was finalized and effective as of April 27, 2018. Certain terms of the compromise with respect to NRG and GenOn Mid-Atlantic are as follows:

- Settlement of all pending litigation and objections to the Plan (including with respect to releases and feasibility);
- NRG provided $38 million in letters of credit as new qualifying credit support to GenOn Mid-Atlantic; and
- NRG paid approximately $6 million as reimbursement of professional fees incurred by certain of GenOn Mid-Atlantic's stakeholders in connection with the GenMA Settlement.

Planned Dispositions

On November 1, 2018, the Company offered to Clearway Energy, Inc. its ownership interest in Agua Caliente Borrower 1, LLC, for approximately $120 million, which owns a 35% interest in Agua Caliente, a 290 MW utility-scale solar project located in Dateland, Arizona. The offer expired on January 31, 2019, with no action taken by Clearway Energy, Inc. As a result, the right of first offer agreement with Clearway Energy, Inc. has expired and NRG's interest in Agua Caliente is no longer subject to a right of first offer thereunder.

Dispositions

On August 1, 2018, the Company completed the sale of 100% of its ownership interests in BETM to Diamond Energy Trading and Marketing, LLC for $71 million, net of working capital adjustments, which resulted in a gain of $15 million on the sale. The sale also resulted in the release and return of approximately $119 million of letters of credit, $32 million of parent guarantees, and $4 million of net cash collateral to NRG.

On June 29, 2018, the Company completed the sale of Canal 3 to Stonepeak Kestrel for cash proceeds of approximately $16 million and recorded a gain of $17 million. Prior to the sale, Canal 3 entered into a financing arrangement and received cash proceeds of $167 million, of which $151 million was distributed to the Company. The related debt was non-recourse to NRG and was transferred to Stonepeak Kestrel in connection with the sale of Canal 3.

In addition, the Company completed other asset sales for $28 million of cash proceeds during the year ended December 31, 2018.

2016 Dispositions

Disposition of Majority Interest in EVgo

On June 17, 2016, the Company completed the sale of a majority interest in its EVgo business to Vision Ridge Partners for total consideration of approximately $39 million, including $17 million in cash received, which is net of $3 million in working capital adjustments, $15 million contributed as capital to the EVgo business and $7 million of future contributions by Vision Ridge Partners, all of which were determined based on forecasted cash requirements to operate the business in future periods. In addition, the Company has future earnout potential of up to $70 million based on future profitability targets. NRG retained its original financial obligation of $103 million under its agreement with the CPUC whereby EVgo will build at least 200 public fast charging Freedom Station sites and perform the associated work to prepare 10,000 commercial and multi-family parking spaces for electric vehicle charging in California. As part of the sale, NRG has contracted with EVgo to continue to build the remaining required Freedom Stations and commercial and multi-family parking spaces for electric vehicle charging required under this obligation and EVgo will be directly reimbursed by NRG for the costs. As a result of the sale, the Company recorded a loss on sale of $78 million during the second quarter of 2016, which reflects the loss on the sale of the equity interest of $27 million and the accrual of NRG's remaining obligation under its agreement with the CPUC of $56 million, of which $6 million remains as of December 31, 2018. On February 22, 2017, the Company and CPUC entered into a second amendment to the agreement which extended the operating period commitment for the Freedom Stations to December 5, 2020. The Company's remaining 23.7% interest in EVgo is accounted for as an equity method investment.

Rockford Disposition

On May 12, 2016, the Company entered into an agreement with RA Generation, LLC to sell 100% of its interests in the Rockford I and Rockford II generating stations, or Rockford, for cash consideration of $55 million, subject to adjustments for working capital and the results of the PJM 2019/2020 base residual auction. Rockford is a 450 MW natural gas facility located in Rockford, Illinois. The transaction triggered an indicator of impairment as the sales price was less than the carrying amount of the assets and, as a result, the assets were considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount of the assets and the agreed-upon sales price. The Company recorded an impairment loss of $17 million during the quarter ended June 30, 2016 to reduce the carrying amount of the assets held for sale to the fair market value. On July 12, 2016, the Company completed the sale of Rockford for cash proceeds of $56 million, including $1 million in adjustments for the PJM base residual auction results. For further discussion on this impairment, refer to Note 9, Asset Impairments.

Note 4 — Fair Value of Financial Instruments

For cash and cash equivalents, funds deposited by counterparties, accounts and other receivables, accounts payable, restricted cash, and cash collateral posted and received in support of energy risk management activities, the carrying amount approximates fair value because of the short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

The estimated carrying values and fair values of the Company's recorded financial instruments not carried at fair market value are as follows:

	As of December 31,			
	2018		2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets				
Notes receivable	$17	$14	$2	$2
Liabilities				
Long-term debt, including current portion [(a)]	$6,591	$6,697	$9,482	$9,739

(a) Excludes deferred financing costs, which are recorded as a reduction to long-term debt on the Company's consolidated balance sheets

The fair value of the Company's publicly-traded long-term debt is based on quoted market prices and is classified as Level 2 within the fair value hierarchy. The fair value of debt securities, non-publicly traded long-term debt, and certain notes receivable of the Company are based on expected future cash flows discounted at market interest rates or current interest rates for similar instruments with equivalent credit quality and are classified as Level 3 within the fair value hierarchy. The following table presents the level within the fair value hierarchy for long-term debt, including current portion as of December 31, 2018 and 2017:

	As of December 31, 2018		As of December 31, 2017	
	Level 2	Level 3	Level 2	Level 3
	(In millions)			
Long-term debt, including current portion	$6,528	$169	$7,432	$2,307

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Fair Value Accounting under ASC 820

ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access as of the measurement date. NRG's financial assets and liabilities utilizing Level 1 inputs include active exchange-traded securities, energy derivatives, and trust fund investments.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. NRG's financial assets and liabilities utilizing Level 2 inputs include fixed income securities, exchange-based derivatives, and over the counter derivatives such as swaps, options and forward contracts.
- Level 3 — unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date. NRG's financial assets and liabilities utilizing Level 3 inputs include infrequently-traded, non-exchange-based derivatives and commingled investment funds, and are measured using present value pricing models.

In accordance with ASC 820, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety.

Recurring Fair Value Measurements

Debt securities, equity securities, and trust fund investments, which are comprised of various U.S. debt and equity securities, and derivative assets and liabilities, are carried at fair market value.

The following tables present assets and liabilities measured and recorded at fair value on the Company's consolidated balance sheets on a recurring basis and their level within the fair value hierarchy:

	As of December 31, 2018			
	Fair Value			
	Total	Level 1	Level 2	Level 3
	(In millions)			
Investments in securities (classified within other current and non-current assets)	$39	$ 2	$18	$ 19
Nuclear trust fund investments:				
Cash and cash equivalents	19	19	—	—
U.S. government and federal agency obligations	46	46	—	—
Federal agency mortgage-backed securities	100	—	100	—
Commercial mortgage-backed securities	22	—	22	—
Corporate debt securities	96	—	96	—
Equity securities	312	312	—	—
Foreign government fixed income securities	4	—	4	—
Other trust fund investments:				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Commodity contracts	1,042	137	796	109
Interest rate contracts	39	—	39	—
Measured using net asset value practical expedient:				
Equity securities-nuclear trust fund investments	64	—	—	—
Equity securities	8	—	—	—
Total assets	$1,792	$ 517	$1,075	$ 128
Derivative liabilities:				
Commodity contracts	$977	$ 224	$664	$ 89
Total liabilities	$977	$ 224	$664	$ 89

	As of December 31, 2017			
	Fair Value			
	Total	Level 1	Level 2	Level 3
Investments in securities (classified within other current or non-current assets)	$39	$ 3	$ 17	$ 19
Nuclear trust fund investments:				
Cash and cash equivalents	47	45	2	—
U.S. government and federal agency obligations	43	42	1	—
Federal agency mortgage-backed securities	82	—	82	—
Commercial mortgage-backed securities	14	—	14	—
Corporate debt securities	99	—	99	—
Equity securities	334	334	—	—
Foreign government fixed income securities	5	—	5	—
Other trust fund investments:				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Commodity contracts	744	191	509	44
Interest rate contracts	39	—	39	—
Measured using net asset value practical expedient:				
Equity securities-nuclear trust fund investments	68	—	—	—
Equity securities	8	—	—	—
Total assets	$1,523	$ 616	$ 768	$ 63
Derivative liabilities:				
Commodity contracts	$674	$ 257	$ 358	$ 59
Interest rate contracts	6	—	6	—
Total liabilities	$680	$ 257	$ 364	$ 59

The following tables reconcile, for the years ended December 31, 2018 and 2017, the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements at least annually using significant unobservable inputs:

	For the Year Ended December 31, 2018 Fair Value Measurement Using Significant Unobservable Inputs (Level 3)		
	Debt Securities	Derivatives (a)	Total
	(In millions)		
Beginning balance as of January 1, 2018	$19	$ (15)	$4
Contracts acquired in XOOM acquisition	—	12	12
Total losses realized/unrealized included in earnings	—	(21)	(21)
Purchases	—	41	41
Transfers into Level 3 (b)	—	5	5
Transfers out of Level 3 (b)	—	(2)	(2)
Ending balance as of December 31, 2018	$19	$ 20	$39
Losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets or liabilities still held as of December 31, 2018	$—	$ (17)	$(17)

(a) Consists of derivatives assets and liabilities, net

(b)

Transfers into/out of Level 3 are related to the availability of external broker quotes, and are valued as of the end of the reporting period. All transfers into/out of Level 3 are from/to Level 2

	For the Year Ended December 31, 2017 Fair Value Measurement Using Significant Unobservable Inputs (Level 3)		
	Debt Securities	Derivatives [a]	Total
	(In millions)		
Beginning balance as of January 1, 2017	$17	$ (64)	$(47)
Total gains realized/unrealized included in earnings	2	37	39
Purchases	—	(4)	(4)
Contracts reclassified to held-for-sale		4	4
Transfers into Level 3 [b]	—	(1)	(1)
Transfer out of Level 3 [b]	—	13	13
Ending balance as of December 31, 2017	$19	$ (15)	$4
Gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets or liabilities still held as of December 31, 2017	$—	$ 1	$1

(a) Consists of derivatives assets and liabilities, net

(b) Transfers into/out of Level 3 are related to the availability of external broker quotes, and are valued as of the end of the reporting period. All transfers into/out of Level 3 are from/to Level 2

Realized and unrealized gains and losses included in earnings that are related to the energy derivatives are recorded in operating revenues and cost of operations.

Non-derivative fair value measurements

NRG's investments in debt securities are classified as Level 3 and consist of non-traded debt instruments that are valued based on third-party market value assessments.

The trust fund investments are held primarily to satisfy NRG's nuclear decommissioning obligations. These trust fund investments hold debt and equity securities directly and equity securities indirectly through commingled funds. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. In addition, U.S. government and federal agency obligations are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of corporate debt securities are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized in Level 2. Certain equity securities, classified as commingled funds, are analogous to mutual funds, are maintained by investment companies, and hold certain investments in accordance with a stated set of fund objectives. The fair value of the equity securities classified as commingled funds are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares in the commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See also Note 6, Nuclear Decommissioning Trust Fund.

Derivative fair value measurements

A portion of the Company's contracts are exchange-traded contracts with readily available quoted market prices. A majority of NRG's contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company's prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote, then the mid-point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. A significant portion of the fair value of the Company's derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate those transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represents contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up 10% of derivative assets and 9% of derivative liabilities. The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk, which for interest rate swaps is calculated utilizing the bilateral method based on published default probabilities. For commodities, to the extent that NRG's net exposure under a specific master agreement is an asset, the Company uses the counterparty's default swap rate. If the exposure under a specific master agreement is a liability, the Company uses NRG's default swap rate. For interest rate swaps and commodities, the credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG's liabilities or that a market participant would be willing to pay for NRG's assets. As of December 31, 2018 and December 31, 2017 the credit reserve did not result in a significant change in fair value.

The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2018, and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts NRG holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible, however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

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

The following tables quantify the significant unobservable inputs used in developing the fair value of the Company's Level 3 positions as of December 31, 2018 and 2017:

	Significant Unobservable Inputs December 31, 2018						
	Fair Value				Input/Range		
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
	(In millions)						
Power Contracts	$ 89	$ 75	Discounted Cash Flow	Forward Market Price (per MWh)	$ 1	$ 214	$ 31
FTRs	20	14	Discounted Cash Flow	Auction Prices (per MWh)	(90)	34	—
	$ 109	$ 89					

	Significant Unobservable Inputs December 31, 2017						
	Fair Value				Input/Range		
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
	(In millions)						
Power Contracts	$ 33	$ 47	Discounted Cash Flow	Forward Market Price (per MWh)	$ 10	$ 142	$ 24
FTRs	11	12	Discounted Cash Flow	Auction Prices (per MWh)	(28)	46	—
	$ 44	$ 59					

The following table provides sensitivity of fair value measurements to increases/(decreases) in significant unobservable inputs as of December 31, 2018 and 2017:

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

Under the guidance of ASC 815, entities may choose to offset cash collateral posted or received against the fair value of derivative positions executed with the same counterparties under the same master netting agreements. The Company has chosen not to offset positions as defined in ASC 815. As of December 31, 2018, the Company recorded $287 million of cash collateral posted and $33 million of cash collateral received on its balance sheet.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, Summary of Significant Accounting Policies, the following item is a discussion of the concentration of credit risk for the Company's financial instruments. Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. The Company monitors and manages credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties' credit limits; (iii) the use of credit mitigation measures such as margin, collateral, prepayment arrangements, or volumetric limits; (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty risk by having a diversified portfolio of counterparties. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at the Company to cover the credit risk of the counterparty until positions settle.

Counterparty Credit Risk

As of December 31, 2018, counterparty credit exposure, excluding credit exposure from RTOs, ISOs, and registered commodity exchanges and certain long-term agreements, was $301 million and NRG held collateral (cash and letters of credit) against those positions of $123 million, resulting in a net exposure of $180 million. Approximately 66% of the Company's exposure before collateral is expected to roll off by the end of 2020. Counterparty credit exposure is valued through observable market quotes and discounted at a risk free interest rate. The following tables highlight net counterparty credit exposure by industry sector and by counterparty credit quality. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and NPNS, and non-derivative transactions. The exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	Net Exposure [a] [b] (% of Total)	
Utilities, energy merchants, marketers and other	89	%
Financial institutions	11	
Total	100	%

Category	Net Exposure [a] [b] (% of Total)	
Non-Investment grade/Non-Rated	51	%
Investment grade	49	
Total	100	%

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

(b) The figures in the tables above exclude potential counterparty credit exposure related to RTOs, ISOs, registered commodity exchanges and certain long term contracts.

The Company currently has no exposure to any individual wholesale counterparty in excess of 10% of the total net exposure discussed above as of December 31, 2018. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company's financial position or results of operations from nonperformance by any of NRG's counterparties.

RTOs and ISOs

The Company participates in the organized markets of CAISO, ERCOT, ISO-NE, MISO, NYISO and PJM, known as RTOs or ISOs. Trading in these markets is approved by FERC, or in the case of ERCOT, approved by the PUCT and includes credit policies that, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. As a result, the counterparty credit risk to these markets is limited to NRG’s share of overall market and are excluded from the above exposures.

Exchange Traded Transactions

The Company enters into commodity transactions on registered exchanges, notably ICE and NYMEX. These clearinghouses act as the counterparty and transactions are subject to extensive collateral and margining requirements. As a result, these commodity transactions have limited counterparty credit risk.

Long Term Contracts

Counterparty credit exposure described above excludes credit risk exposure under certain long term contracts, including California tolling agreements and solar PPAs. As external sources or observable market quotes are not available to estimate such exposure, the Company values these contracts based on various techniques including, but not limited to, internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Based on these valuation techniques, as of December 31, 2018, aggregate credit risk exposure managed by NRG to these counterparties was approximately $434 million for the next five years. This amount excludes potential credit exposures for projects with long-term PPAs that have not reached commercial operations and any exposure for entities classified as a discontinued operation.

NRG through its unconsolidated affiliates Ivanpah and Agua Caliente has exposure to PG&E of approximately $321 million for the next five years. As a result of the bankruptcy filing by PG&E on January 29, 2019, it is uncertain whether and to what extent the bankruptcy may have on these contracts. For further discussion see Note 15, Investments Accounted for by the Equity Method and Variable Interest Entities.

Retail Customer Credit Risk

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

As of December 31, 2018, the Company's retail customer credit exposure to C&I and Mass customers was diversified across many customers and various industries, as well as government entities. The Company is also subject to risk with respect to its residential solar customers. The Company's bad debt expense was $85 million, $68 million, and $45 million for the years ending December 31, 2018, 2017, and 2016, respectively. Current economic conditions may affect the Company's customers' ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Note 5 — Accounting for Derivative Instruments and Hedging Activities

ASC 815 requires the Company to recognize all derivative instruments on the balance sheet as either assets or liabilities and to measure them at fair value each reporting period unless they qualify for a NPNS exception. The Company may elect to designate certain derivatives as cash flow hedges, if certain conditions are met, and defer the change in fair value of the derivatives to accumulated OCI, until the hedged transactions occur and are recognized in earnings.

For derivatives that are not designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Certain derivative instruments may qualify for the NPNS exception and are therefore exempt from fair value accounting treatment. ASC 815 applies to NRG's energy related commodity contracts, interest rate swaps, and equity contracts.

As the Company engages principally in the trading and marketing of its generation assets and retail businesses, some of NRG's commercial activities qualify for NPNS accounting. Most of the retail load contracts either qualify for the NPNS exception or fail to meet the criteria for a derivative and the majority of the retail supply and fuels supply contracts are recorded under mark-to-market accounting. All of NRG's hedging and trading activities are subject to limits within the Company's Risk Management Policy.

Energy-Related Commodities

To manage the commodity price risk associated with the Company's competitive supply activities and the price risk associated with wholesale power sales from the Company's electric generation facilities and retail power sales from NRG's retail businesses, NRG enters into a variety of derivative and non-derivative hedging instruments, utilizing the following:

- Forward contracts, which commit NRG to purchase or sell energy commodities or purchase fuels in the future;
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument;
- Swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual, or notional, quantity;
- Option contracts, which convey to the option holder the right but not the obligation to purchase or sell a commodity;
- Extendable swaps, which include a combination of swaps and options executed simultaneously for different periods. This combination of instruments allows NRG to sell out-year volatility through call options in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. The above-market swap combined with its later-year call option are priced in aggregate at market at the trade's inception; and
- Weather derivative products used to mitigate a portion of lost revenue due to weather.

The objectives for entering into derivative contracts designated as hedges include:

- Fixing the price of a portion of anticipated power purchases for the Company's retail sales;
- Fixing the price for a portion of anticipated future electricity sales that provides an acceptable return on the Company's electric generation operations; and
- Fixing the price of a portion of anticipated fuel purchases for the operation of the Company's power plants.

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

As of December 31, 2018, NRG's derivative assets and liabilities consisted primarily of the following:

- Forward and financial contracts for the purchase/sale of electricity and related products economically hedging NRG's generation assets' forecasted output or NRG's retail load obligations through 2034;
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of NRG's generation assets through 2019; and
- Other energy derivatives instruments extending through 2029.

Also, as of December 31, 2018, NRG had other energy-related contracts that did not meet the definition of a derivative instrument or qualified for the NPNS exception and were therefore exempt from fair value accounting treatment as follows:

- Load-following forward electric sale contracts extending through 2034;
- Power tolling contracts through 2029;
- Coal purchase contracts through 2021;
- Power transmission contracts through 2025;
- Natural gas transportation contracts and storage agreements through 2030; and
- Coal transportation contracts through 2029.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company's issuance of variable rate debt. In order to manage the Company's interest rate risk, NRG enters into interest rate swap agreements. As of December 31, 2018, NRG's derivative assets consisted of interest rate derivative instruments on recourse debt extending through 2021.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG's open derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of December 31, 2018 and 2017. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

Commodity	Units	Total Volume December 31, 2018	December 31, 2017
		(In millions)	
Emissions	Short Ton	(2)	1
Renewables Energy Certificates	Certificates	1	—
Coal	Short Ton	13	21
Natural Gas	MMBtu	(330)	(20)
Oil	Barrels	1	—
Power	MWh	1	23
Capacity	MW/Day	(1)	(1)
Interest	Dollars	$1,000	$ 1,060
Equity	Shares	—	1

The increase in the natural gas position was primarily the result of additional generation hedge positions.

Fair Value of Derivative Instruments

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

(In millions)	Fair Value Derivative Assets December 31, 2018	December 31, 2017	Derivative Liabilities December 31, 2018	December 31, 2017
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$17	$ 8	$ —	$ 1
Interest rate contracts long-term	22	31	—	5
Commodity contracts current	747	616	673	536
Commodity contracts long-term	295	128	304	138
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	$1,081	$ 783	$ 977	$ 680

The Company has elected to present derivative assets and liabilities on the balance sheet on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. In addition, collateral received or paid on the Company's derivative assets or liabilities are recorded on a separate line item on the balance sheet. The following table summarizes the offsetting derivatives by counterparty master agreement level and collateral received or paid:

	Gross Amounts Not Offset in the Statement of Financial Position			
	Gross Amounts of Recognized Assets/Liabilities	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
As of December 31, 2018	(In millions)			
Commodity contracts:				
Derivative assets	$1,042	$ (778)	$ (31)	$ 233
Derivative liabilities	(977)	778	114	(85)
Total commodity contracts	65	—	83	148
Interest rate contracts:				
Derivative assets	39	—	—	39
Total interest rate contracts	39	—	—	39
Total derivative instruments	$104	$ —	$ 83	$ 187

	Gross Amounts Not Offset in the Statement of Financial Position			
	Gross Amounts of Recognized Assets/Liabilities	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
As of December 31, 2017	(In millions)			
Commodity contracts:				
Derivative assets	$744	$ (578)	$ (11)	$ 155
Derivative liabilities	(674)	578	72	(24)
Total commodity contracts	70	—	61	131
Interest rate contracts:				
Derivative assets	39	—	—	39
Derivative liabilities	(6)	—	—	(6)
Total interest rate contracts	33	—	—	33
Total derivative instruments	$103	$ —	$ 61	$ 164

Accumulated Other Comprehensive Income

The following table summarizes the effects on NRG's accumulated OCI balance attributable to cash flow hedge derivatives, net of tax:

	Interest Rate Contracts		
	2018	2017	2016
	(In millions)		
Accumulated OCI beginning balance	$(54)	$(66)	$(101)
Reclassified from accumulated OCI to income:			
Due to realization of previously deferred amounts	8	12	21
Mark-to-market of cash flow hedge accounting contracts	21	—	14
Sale of NRG Yield and Renewables	$25	$—	$—
Accumulated OCI ending balance, net of $0, $8 and $16 tax	$—	$(54)	$(66)

Amounts reclassified from accumulated OCI into income are recorded in discontinued operations.

Accounting guidelines require a high degree of correlation between the derivative and the hedged item throughout the period in order to qualify as a cash flow hedge. As of December 31, 2016, the Company's regression analysis for certain yield interest rate swaps, while positively correlated, did not meet the required threshold for cash flow hedge accounting. As a result, the Company de-designated these derivatives as cash flow hedges as of December 31, 2016, and prospectively marked these derivatives to market through the income statement until the assets were sold.

The Company's regression analysis for certain Yield interest rate swaps, while positively correlated, no longer contain matching terms for cash flow hedge accounting. As a result, the Company voluntarily de-designated these derivatives as cash flow hedges as of April 28, 2017, and prospectively marked these derivatives to market through the income statement until the assets were sold.

Impact of Derivative Instruments on the Statement of Operations

Unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedges are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that have not been designated as cash flow hedges, and trading activity on the Company's statement of operations. The effect of commodity hedges is included within operating revenues and cost of operations and the effect of interest rate hedges is included in interest expense.

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Unrealized mark-to-market results			
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$(73)	$47	$(128)
Reversal of acquired gain positions related to economic hedges	(10)	—	(12)
Net unrealized gains on open positions related to economic hedges	97	159	12
Total unrealized mark-to-market gains/(losses) for economic hedging activities	14	206	(128)
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	(12)	(25)	10
Net unrealized gains on open positions related to trading activity	29	14	18
Total unrealized mark-to-market gains/(losses) for trading activity	17	(11)	28
Total unrealized gains/(losses)	$31	$195	$(100)

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Unrealized (losses)/gains included in operating revenues	$(113)	$241	$(608)
Unrealized gains/(losses) included in cost of operations	144	(46)	508
Total impact to statement of operations — energy commodities	$31	$195	$(100)
Total impact to statement of operations — interest rate contracts	$—	$4	$(8)

The reversal of gain or loss positions acquired as part of acquisitions were valued based upon the forward prices on the acquisition dates. The roll-off amounts were offset by realized gains or losses at the settled prices and are reflected in revenue or cost of operations during the same period.

For the year ended December 31, 2018, the $97 million gain from economic hedge positions was primarily the result of an increase in the value of forward purchases of ERCOT heat rate contracts due to ERCOT heat rate expansion.

For the year ended December 31, 2017, the $159 million gain from economic hedge positions was primarily the result of an increase in the value of forward purchases of ERCOT heat rate contracts due to ERCOT heat rate expansion.

For the year ended December 31, 2016, the $12 million gain from economic hedge positions was primarily the result of an increase in the value of forward purchases of natural gas due to an increase in natural gas prices.

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Credit Risk Related Contingent Features

Certain of the Company's hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed "adequate assurance" under the agreements, or require the Company to post additional collateral if there were a one notch downgrade in the Company's credit rating. The collateral required for contracts that have adequate assurance clauses that are in net liability positions as of December 31, 2018 was $16 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2018 was $14 million. The Company is also a party to certain marginable agreements under which it has a net liability position, but the counterparty has not called for the collateral due, which was approximately $11 million as of December 31, 2018. See Note 4, Fair Value of Financial Instruments, for discussion regarding concentration of credit risk.

Note 6 — Nuclear Decommissioning Trust Fund

NRG's Nuclear Decommissioning Trust Fund assets, which are for the decommissioning of STP, are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. Although NRG is responsible for managing the decommissioning of its 44% interest in STP, the predecessor utilities that owned STP are authorized by the PUCT to collect decommissioning funds from their ratepayers to cover decommissioning costs on behalf of NRG. NRC requirements determine the decommissioning cost estimate which is the minimum required level of funding. In the event that funds from the ratepayers that accumulate in the nuclear decommissioning trust are ultimately determined to be inadequate to decommission the STP facilities, the utilities will be required to collect through rates charged to rate payers all additional amounts, with no obligation from NRG, provided that NRG has complied with PUCT rules and regulations regarding decommissioning trusts. Following completion of the decommissioning, if surplus funds remain in the decommissioning trusts, any excess will be refunded to the respective ratepayers of the utilities.

NRG accounts for the Nuclear Decommissioning Trust Fund in accordance with ASC 980, Regulated Operations, or ASC 980, because the Company's nuclear decommissioning activities are subject to approval by the PUCT, with regulated rates that are designed to recover all decommissioning costs and that can be charged to and collected from the ratepayers per PUCT mandate. Since the Company is in compliance with PUCT rules and regulations regarding decommissioning trusts and the cost of decommissioning is the responsibility of the Texas ratepayers, not NRG, all realized and unrealized gains or losses (including other-than-temporary impairments) related to the Nuclear Decommissioning Trust Fund are recorded to the Nuclear Decommissioning Trust liability and are not included in net income or accumulated other comprehensive income, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses for the securities held in the trust funds, as well as information about the contractual maturities of those securities.

	As of December 31, 2018				As of December 31, 2017			
(In millions, except otherwise noted)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)	Fair Value	Unrealized Gains	Unrealized Losses	Weighted-average maturities (in years)
Cash and cash equivalents	$19	$ —	$ —	—	$47	$ —	$ —	—
U.S. government and federal agency obligations	46	1	—	12	43	1	—	11
Federal agency mortgage-backed securities	100	1	2	23	82	1	1	23
Commercial mortgage-backed securities	22	—	1	22	14	—	—	20
Corporate debt securities	96	1	2	11	99	2	1	11
Equity securities	376	231	1	—	402	272	—	—
Foreign government fixed income securities	4	—	—	9	5	—	—	9
Total	$663	$ 234	$ 6		$692	$ 276	$ 2	

The following table summarizes proceeds from sales of available-for-sale securities and the related realized gains and losses from these sales. The cost of securities sold is determined using the specific identification method.

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Realized gains	$17	$22	$26
Realized (losses)	(13)	(8)	(11)
Proceeds from sale of securities	513	501	510

Note 7 — Inventory

Inventory consisted of:

	As of December 31,	
	2018	2017
	(In millions)	
Fuel oil	$ 74	$ 86
Coal	97	110
Natural gas	28	24
Spare parts	213	233
Total Inventory	$ 412	$ 453

The Company recorded a lower of weighted average cost or market adjustment related to fuel oil for the years ended, December 21, 2018 and 2017 of $3 million and $33 million respectively.

Note 8 — Property, Plant and Equipment

The Company's major classes of property, plant, and equipment were as follows:

	As of December 31,		Depreciable
	2018	2017	Lives
	(In millions)		
Facilities and equipment	$3,763	$6,904	1-40 Years
Land and improvements	347	468	
Nuclear fuel	212	235	5 Years
Office furnishings and equipment	431	421	2-10 Years
Construction in progress	106	201	
Total property, plant, and equipment	4,859	8,229	
Accumulated depreciation	(1,811)	(2,255)	
Net property, plant, and equipment	$3,048	$5,974	

The Company recorded long-lived asset impairments during the years ended December 31, 2018 and 2017, as further described in Note 9, Asset Impairments.

Note 9 — Asset Impairments
2018 Impairment Losses

Guam — During the fourth quarter of 2018, the Company concluded its wholly-owned subsidiary, NRG Solar Guam, LLC, was held for sale after board approval and advanced negotiations to sell the business. Accordingly, the Company recorded the assets and liabilities at fair market value as of December 31, 2018 based on the contractual sale price, which resulted in an impairment loss of $12 million. On February 20, 2019, the Company completed the sale of Guam for cash consideration of approximately $8 million.
Keystone and Conemaugh — On September 5, 2018, the Company sold its approximately 3.7% interests in the Keystone and Conemaugh generating stations. NRG recorded impairment losses of $14 million for Keystone and $14 million for Conemaugh to adjust the carrying amount of the assets to fair value based on the contractual sale price.
Dunkirk — During the second quarter of 2018, NRG ceased its development of the project to add gas capability at the Dunkirk generating station. The project was put on hold in 2015 pending the resolution of a lawsuit filed by Entergy Corporation against the NYPSC, which challenged the legality of its contract with Dunkirk. The lawsuit was later dropped and development continued, but the delay imposed a new requirement on Dunkirk to enter into the NYISO interconnection study process. The NYISO studies have concluded that extensive electric system upgrades would be necessary for the station to return to service. This would cause the Company to incur a material increase in cost and delay the project schedule that would render the project impractical. Consequently, the Company has recorded an impairment loss of $46 million, reducing the carrying amount of the related assets to $0.
Other Impairments — As of December 31, 2018, the Company recorded additional asset impairment losses of approximately $13 million and impairment losses on equity method investments of $15 million.

2017 Impairment Losses

South Texas Project — The Company recognized an impairment loss of $1,248 million related to its interest in STP as a result of the decrease in the Company's view of long-term power prices in ERCOT.

Indian River — The Company recognized an impairment loss of $36 million for Indian River as a result of the decrease in the Company's view of long-term power prices in PJM.

Keystone and Conemaugh — The Company recognized impairment losses of $35 million for Keystone and $35 million for Conemaugh as a result of the decrease in the Company's view of long-term power prices in PJM.
Bacliff Project — On June 16, 2017, NRG Texas Power LLC provided notice to BTEC New Albany, LLC that it was exercising its right to terminate the Amended and Restated Membership Interest Purchase Agreement, or MIPA, due to the Bacliff Project, a new peaking facility at the former P.H. Robinson Electric Generating Station, not achieving commercial completion by the contractual expiration date of May 31, 2017. As a result of the MIPA termination, the Company recorded an impairment loss of $41 million to reduce the carrying amount of the related construction in progress to $0 during the second quarter of 2017. Subsequent to the MIPA termination, BTEC filed claims against NRG Texas Power LLC with respect to the termination of the MIPA and NRG filed counterclaims against BTEC as further described in Note 21, Commitments and Contingencies. On June 7, 2018, the parties resolved all claims and counterclaims in the lawsuit.

Petra Nova Parish Holdings — In connection with the preparation of the annual budget during the fourth quarter, management revised its view of oil production expectations with respect to Petra Nova Parish Holdings. As a result, the Company reviewed its 50% interest in Petra Nova Parish Holdings for impairment utilizing the other-than-temporary impairment model. In determining fair value, the Company utilized an income approach and considered project specific assumptions for the future project cash flows. The carrying amount of the Company's equity method investment exceeded the fair value of the investment and the Company concluded that the decline is considered to be other-than-temporary. As a result, the Company measured the impairment loss as the difference between the carrying amount and the fair value of the investment and recorded an impairment loss of $69 million.

Other Impairments — During the year ended 2017, the Company recorded impairment losses of $29 million in connection with renewable assets that were not divested as part of the sale of NRG Yield and the Renewables Platform. In addition, the Company recorded an impairment loss of $20 million related to excess SO_2 allowances and $10 million in impairment losses for other investments.

2016 Impairment Losses

Rockford — As described in Note 3, Acquisitions, Discontinued Operations and Dispositions, on May 12, 2016, the Company entered into an agreement with RA Generation, LLC to sell 100% of its interests in the Rockford generating stations for cash consideration of $55 million. The transaction triggered an indicator of impairment as the sale price was less than the carrying amount of the assets, and, as a result, the assets were considered to be impaired. The Company measured the impairment loss as the difference between the carrying amount of the assets and the agreed-upon sale price. The Company recorded an impairment loss of $17 million during the year ended December 31, 2016, to reduce the carrying amount of the assets held for sale to their fair market value.

Long Beach — During the fourth quarter of 2016, the Company determined that by the end of 2017 it would retire its Long Beach generation station located in Long Beach, California. The generating station was not awarded a PPA extension in SCE's capacity auction during the fourth quarter of 2016 for the PPA set to expire on July 31, 2017. The Company considered this to be an indicator of impairment and performed an impairment test. The Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets and recorded an impairment loss of $36 million. Subsequently, management decided to continue to operate in 2018, which did not significantly impact fair value.

Petra Nova Parish Holdings — During the first quarter of 2016, management changed its plans with respect to its future capital commitments driven in part by the continued decline in oil prices. As a result, the Company reviewed its 50% interest in Petra Nova Parish Holdings for impairment utilizing the other-than-temporary impairment model. In determining fair value, the Company utilized an income approach and considered project specific assumptions for the future project cash flows. The carrying amount of the Company's equity method investment exceeded the fair value of the investment and the Company concluded that the decline is considered to be other-than-temporary.. As a result, the Company measured the impairment loss as the difference between the carrying amount and the fair value of the investment and recorded an impairment loss of $140 million.

Community Wind North and Sherbino — During the fourth quarter of 2016, the Company offered several projects to NRG Yield including its interest in Community Wind North. The offer price was below its carrying amount and this decline in fair value was determined to be other-than-temporary. Accordingly, the Company recorded an impairment loss of $36 million to reduce its carrying amount to fair value. In connection with the preparation of the annual budget, the Company noted that due to the anticipated difficulty in refinancing Sherbino's debt, the project's fair value had decreased significantly below its carrying amount and determined the impairment to be other-than-temporary. Accordingly, the Company determined that an impairment existed and recorded an impairment loss on its investment in Sherbino of $70 million.

Other Impairments — During 2016, the Company recorded other impairment losses of $29 million in connection with renewable assets that were not divested as part of the sale of NRG Yield and the Renewables Platform. In addition, the Company also recorded impairment losses of $23 million in excess SO_2 allowances, $19 million for other intangible assets, $19 million in previously purchased solar panels and $22 million in other investments.

Note 10 — Goodwill and Other Intangibles

Goodwill

NRG's goodwill balance was $573 million and $539 million as of December 31, 2018 and 2017, respectively. The increase in goodwill is due to the acquisition of XOOM. As of December 31, 2018 and 2017, NRG had approximately $366 million and $460 million, respectively, of goodwill that is deductible for U.S. income tax purposes in future periods. As of December 31, 2018, goodwill consisted of $165 million associated with the acquisition of Midwest Generation and $408 million for Retail business acquisitions, including Texas non-commodity and XOOM.

2017 Impairments of Goodwill

BETM — During the fourth quarter of 2017, the Company concluded that BETM was held for sale following board approval and advanced negotiations to sell the business. Accordingly, the Company recorded the assets and liabilities at fair market value as of December 31, 2017, which resulted in an impairment loss of $90 million to record BETM's goodwill at fair market value. The remaining goodwill balance for BETM of $21 million was included within non-current assets held-for-sale as of December 31, 2017.

2016 Impairments of Goodwill

During the year ended December 31, 2016, the Company recorded a goodwill impairment charge of $337 million related to its Texas Generation reporting unit, reducing the goodwill balance for Texas Generation to zero.

In connection with the annual impairment assessment, the Company performed step one of the two-step impairment test for the Texas Generation reporting unit, for which $1.7 billion of goodwill was recognized as part of the Texas Genco acquisition in 2006 and $1.4 billion was written off in 2015. The Company determined the fair value of the Texas Generation reporting unit primarily using an income approach through which the Company applied a discounted cash flow methodology to the long-term budgets for all plants in the regions. Significant inputs impacting the income approach include the Company's views of power and fuel prices for the first five-year period and the Company's view for the longer term, which were finalized in connection with the preparation of the annual budget, projected generation based on an hourly dispatch meant to simulate the dispatch of each unit into the power market which is impacted by power prices, fuel prices, and the physical and economic characteristics of each plant, intangible value to Texas Generation for synergies it provides to NRG's retail businesses, and the discount rate applied to cash flow projections. Under step one, the estimated fair value of the Texas Generation invested capital was 43% below its carrying value as of December 31, 2016, and the Company concluded step two was required. Based on the results of step two of the impairment test, the Company determined the carrying amount of the reporting unit was higher than the fair value, and accordingly, the Company recognized an impairment loss of $337 million as of December 31, 2016.

Intangible Assets

The Company's intangible assets as of December 31, 2018, primarily reflect intangible assets established with the acquisitions of various companies, including Texas Genco, Reliant Energy, Green Mountain Energy, Dominion, XOOM, Discount Power, Energy Alternatives, Energy Plus, Energy Systems, Energy Curtailment Specialists, Pioneer Energy, Stat Energy and Source Power & Gas. Intangible assets are comprised of the following:

- Energy supply contracts — These represent the fair value at the acquisition date of in-market contracts for the purchase of energy to serve retail electric customers. The contracts are amortized to cost of operations based on the expected delivery under the respective contracts.
- Customer contracts — These intangibles represent the fair value at the acquisition date of contracts that primarily provide electricity to Reliant Energy's and Green Mountain Energy's C&I customers. These contracts are amortized to revenues based on expected volumes to be delivered for the portfolio.
- Customer relationships — These intangibles represent the fair value at the acquisition date of acquired businesses' customer base. The customer relationships are amortized to depreciation and amortization expense based on the expected discounted future net cash flows by year.
- Marketing partnerships — These intangibles represent the fair value at the acquisition date of existing agreements with loyalty and affinity partners. The marketing partnerships are amortized to depreciation and amortization expense based on the expected discounted future net cash flows by year.
- Trade names — These intangibles are amortized to depreciation and amortization expense on a straight-line basis.
- Emission Allowances — These intangibles primarily consist of SO_2 and NO_x emission allowances established with the 2006 Texas Genco acquisition and also include RGGI emission credits which NRG began purchasing in 2009. These emission allowances are held-for-use and are amortized to cost of operations, with NO_x allowances amortized on a straight-line basis and SO_2 allowances and RGGI credits amortized based on units of production. During the year ended December 31, 2018, the Company recorded an impairment loss of $5 million to reduce the value of excess SO_2 allowances to zero.
- In-market fuel (gas and nuclear) contracts — These intangibles were established with the Texas Genco acquisition in 2006 and are amortized to cost of operations over expected volumes over the life of each contract.
- Other — Consists of renewable energy credits and costs to extend the operating license for STP Units 1 and 2.

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

Year Ended December 31, 2018	Emission Allowances	Contracts Fuel	Customer Contracts	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
January 1, 2018	$755	$49	$ 1	$ 768	$ 88	$342	$77	$2,080
Purchases	33	—	—	—	—	—	28	61
Acquisition of businesses[(a)]	—	—	—	122	43	13	—	178
Usage	(1)	—	—	—	—	—	(26)	(27)
Write-off of fully amortized balances	(107)	—	—	(411)	—	(10)	—	(528)
Impairment	(5)	—	—	(1)	—	—	—	(6)
Other	(16)	—	—	—	—	—	—	(16)
December 31, 2018	659	49	1	478	131	345	79	1,742
Less accumulated amortization	(515)	(45)	(1)	(314)	(61)	(195)	(20)	(1,151)
Net carrying amount	$144	$4	$ —	$ 164	$ 70	$150	$59	$591

(a) The weighted average life of acquired intangibles is: customer relationships 6 years, trade names 7 years, and marketing partnerships 14 years

Year Ended December 31, 2017	Emission Allowances	Contracts Energy Supply	Fuel	Customer Contracts	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
	(In millions)								
January 1, 2017	$780	$54	$72	$ 1	$ 750	$ 88	$342	$75	$2,162
Purchases	27	—	—	—	—	—	—	32	59
Acquisition of businesses	—	—	—	—	18	—	—	—	18
Usage	(10)	—	—	—	—	—	—	(28)	(38)
Write-off of fully amortized balances	—	(54)	(23)	—	—	—	—	—	(77)
Impairment	(20)	—	—	—	—	—	—	—	(20)
Other	(22)	—	—	—	—	—	—	(2)	(24)
December 31, 2017	755	—	49	1	768	88	342	77	2,080
Less accumulated amortization	(583)	—	(45)	(1)	(693)	(54)	(182)	(15)	(1,573)
Net carrying amount	$172	$—	$4	$ —	$ 75	$ 34	$160	$62	$507

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

Amortization	Years Ended December 31, 2018	2017	2016
	(In millions)		
Emission allowances	$39	$71	$62
Energy supply contracts	—	1	6
Fuel contracts	—	1	1
Customer relationships	32	34	48
Marketing partnerships	9	5	8
Trade names	23	23	23
Other	4	3	9
Total amortization	$107	$138	$157

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

Year Ended December 31,	Emission Allowances	Fuel Contracts	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
	(In millions)						
2019	$48	$ —	$ 38	$ 11	$ 24	$ 3	$124
2020	37	1	39	11	25	3	116
2021	43	—	33	10	24	3	113
2022	50	—	23	10	24	3	110
2023	49	1	26	10	24	3	113

Intangible assets held-for-sale — From time to time, management may authorize the transfer from the Company's emission bank of emission allowances held-for-use to intangible assets held-for-sale. Emission allowances held-for-sale are included in other non-current assets on the Company's consolidated balance sheet and are not amortized, but rather expensed as sold. As of December 31, 2018 and 2017, the value of emission allowances held-for-sale is $12 million and $9 million, respectively, and is managed within the Corporate segment. Once transferred to held-for-sale, these emission allowances are prohibited from moving back to held-for-use.

Out-of-market contracts — Due primarily to business acquisitions, NRG acquired certain out-of-market contracts, which are classified as non-current liabilities on NRG's consolidated balance sheet. These include out-of-market lease contracts of $121 million acquired in the acquisition of Midwest Generation. These out-of-market contracts are amortized to cost of operations. As of December 31, 2018 and 2017, the Company had accumulated amortization for out-of-market contracts of $37 million and $29 million, respectively. Upon adoption of ASC 842, Leases, on January 1, 2019, out-of-market lease contracts are included as a component of right-of-use assets.

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

Year Ended December 31,	Leases
2019	$ 8
2020	8
2021	8
2022	8
2023	8

Note 11 — Debt and Capital Leases
Long-term debt and capital leases consisted of the following:

(In millions, except rates)	December 31, 2018	December 31, 2017	December 31, 2018 interest rate %[a]
Recourse debt:			
Senior Notes, due 2022	$ —	$ 992	6.250
Senior Notes, due 2024	733	733	6.250
Senior Notes, due 2026	1,000	1,000	7.250
Senior Notes, due 2027	1,230	1,250	6.625
Senior Notes, due 2028	821	870	5.750
Convertible Senior Notes, due 2048	575	—	2.750
Term loan facility, due 2023	1,698	1,872	L+1.75
Tax-exempt bonds	466	465	4.125 - 6.00
Subtotal recourse debt	6,523	7,182	
Non-recourse debt:			
Ivanpah, due 2033 and 2038[b]	—	1,073	2.285 - 4.256
Agua Caliente, due 2037[c]	—	818	2.395 - 3.633
Agua Caliente Borrower 1, due 2038	86	89	5.430
Midwest Generation, due 2019	48	152	4.390
Other [d]	34	180	various
Subtotal all non-recourse debt	168	2,312	
Subtotal long-term debt (including current maturities)	6,691	9,494	
Capital leases	1	5	various
Subtotal long-term debt and capital leases (including current maturities)	6,692	9,499	
Less current maturities	(72)	(204)	
Less debt issuance costs	(70)	(103)	
Discounts	(101)	(12)	
Total long-term debt and capital leases	$ 6,449	$ 9,180	

(a) As of December 31, 2018, L+ equals 1-month LIBOR plus 1.75%
(b) The Company deconsolidated Ivanpah during the second quarter of 2018
(c) The Company deconsolidated Agua Caliente solar facility during the third quarter of 2018
(d) Guam was reclassified to held for sale during the fourth quarter of 2018

Debt includes the following discounts:

	As of December 31, 2018	2017
	(In millions)	
Term loan facility, due 2023	$ (4)	$ (7)
Midwest Generation, due 2019	(1)	(5)
Convertible Senior Notes, due 2048	(96)	—
Total discounts	$ (101)	$ (12)

Consolidated Annual Maturities
As of December 31, 2018, annual payments based on the maturities of NRG's debt and capital leases are expected to be as follows:

(In millions)

2019	$ 74
2020	26
2021	27
2022	25
2023	1,635
Thereafter	4,905
Total	$ 6,692

Recourse Debt

Issuance of 2048 Convertible Senior Notes

During the second quarter of 2018, NRG issued $575 million in aggregate principal amount of 2.75% Convertible Senior Notes due 2048, or the Convertible Notes. The Convertible Notes are convertible, under certain circumstances, into the Company's common stock, cash or a combination thereof (at NRG's option) at an initial conversion price of $47.74 per common share, which is equivalent to an initial conversion rate of approximately 20.9479 shares of common stock per $1,000 principal amount of Convertible Notes. Interest on the Convertible Notes is payable semi-annually in arrears on June 1 and December 1 of each year, commencing on December 1, 2018. The Convertible Notes mature on June 1, 2048, unless earlier repurchased, redeemed or converted in accordance with their terms. The Convertible Notes are guaranteed by certain NRG subsidiaries. Prior to the close of business on the business day immediately preceding December 1, 2024, the Convertible Notes will be convertible only upon the occurrence of certain events and during certain periods, and thereafter during specified periods as follows:

- from December 1, 2024 until the close of business on the second scheduled trading day immediately before June 1, 2025; and
- from December 1, 2047 until the close of business on the second scheduled trading day immediately before the maturity date.

The Convertible Notes are accounted for in accordance with ASC 470-20, Debt with Conversion and Other Options. Under ASC 470-20, issuers of convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are required to separately account for the liability (debt) and equity (conversion option) components. The carrying amount of the liability component at issuance date of $472 million was calculated by estimating the fair value of similar liabilities without a conversion feature. The residual principal amount of the notes of $103 million was allocated to the equity component with offset to debt discount. The debt discount will be amortized to interest expense using the effective interest method over seven years which is determined to be the expected life of the Convertible Notes.

The Company incurred approximately $12 million in transaction costs in connection with the issuance of the notes. These costs were allocated to the liability and equity components in proportion to the allocation of proceeds. Transaction costs of $10 million, allocated to the liability component, were recognized as deferred financing costs and are amortized over the seven years. Transaction costs of $2 million, allocated to the equity component, were recognized as a reduction of additional paid-in capital.

Issuance of 2028 Senior Notes

On December 7, 2017, NRG issued $870 million of aggregate principal amount at par of 5.75% senior unsecured notes due 2028. The 2028 Senior Notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest is paid semi-annually beginning on July 15, 2018, until the maturity date of January 15, 2028. The proceeds from the issuance of the 2028 Senior Notes were utilized to redeem the Company's 6.625% Senior Notes due 2023.

2018 Senior Note Repurchases

During the year ended December 31, 2018 the Company completed senior note repurchases, as detailed in the table below. In addition, during the year ended December 31, 2018, a $38 million loss on debt extinguishment was recorded for these repurchases, which included the write-off of previously deferred financing costs of $7 million.

In millions, except percentages	Principal Repurchased	Cash Paid (a)	Average Early Redemption Percentage
5.750% senior notes due 2028	$ 29	$ 30	99.24 %
6.250% senior notes due 2022	14	15	103.25 %
Total at June 30, 2018	$ 43	$ 45	
6.250% senior notes due 2022	493	512	103.13 %
5.750% senior notes due 2028	20	20	99.13 %
6.625% senior notes due 2027	20	21	103.06 %

Total at September 30, 2018	$ 576	$ 598		
6.250% senior notes due 2022	485	508	103.13	%
Total at December 31, 2018	$ 1,061	$ 1,106		

(a) Includes accrued interest of $14 million

2017 Senior Note Redemptions

During the year ended December 31, 2017, the Company redeemed $1.5 billion in aggregate principal of its Senior Notes for $1.5 billion. In connection with the redemptions, a $49 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $7 million.

	Principal Repurchased	Cash Paid [(a)]	Average Early Redemption Percentage
Amount in millions, except percentages			
7.625% senior notes due 2018	$ 398	$411	101.42 %
7.875% senior notes due 2021	206	218	102.63 %
6.625% senior notes due 2023	869	915	103.57 %
Total	$ 1,473	$1,544	

(a) Includes accrued interest of $29 million

Senior Notes Early Redemption

As of December 31, 2018, NRG had the following outstanding issuances of senior notes with an early redemption feature, or Senior Notes:

i.6.250% senior notes, issued April 21, 2014 and due November 1, 2024, or the 2024 Senior Notes;
ii.7.250% senior notes, issued May 23, 2016 and due May 15, 2026, or the 2026 Senior Notes;
iii.6.625% senior notes, issued August 2, 2016 and due January 15, 2027, or the 2027 Senior Notes; and
iv.5.750% senior notes, issued December 7, 2017 and due January 15, 2028, or the 2028 Senior Notes.

The Company periodically enters into supplemental indentures for the purpose of adding entities under the Senior Notes as guarantors.

The indentures and the forms of notes provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG. The indentures also provide for customary events of default, which include, among others: nonpayment of principal or interest; breach of other agreements in the indentures; defaults in failure to pay certain other indebtedness; the rendering of judgments to pay certain amounts of money against NRG and its subsidiaries; the failure of certain guarantees to be enforceable; and certain events of bankruptcy or insolvency. Generally, if an event of default occurs, the Trustee or the Holders of at least 25% in principal amount of the then outstanding series of Senior Notes may declare all of the Senior Notes of such series to be due and payable immediately. The terms of the indentures, among other things, limit NRG's ability and certain of its subsidiaries' ability to return capital to stockholders, grant liens on assets to lenders and incur additional debt. Interest is payable semi-annually on the Senior Notes until their maturity dates.

2024 Senior Notes

At any time prior to May 1, 2019, NRG may redeem up to 35% of the aggregate principal amount of the 2024 Senior Notes, at a redemption price equal to 100% of the principal amount, accrued and unpaid interest to the redemption date, plus a premium. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.125% of the note, plus interest payments due on the note from the date of redemption through May 1, 2019 computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after May 1, 2019, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage
May 1, 2019 to April 30, 2020	103.125 %
May 1, 2020 to April 30, 2021	102.083 %
May 1, 2021 to April 30, 2022	101.042 %
May 1, 2022 and thereafter	100.000 %

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2026 Senior Notes

At any time prior to May 15, 2019, NRG may redeem up to 35% of the aggregate principal amount of the 2026 Senior Notes, at a redemption price equal to 107.25% of the principal amount of the notes redeemed, plus accrued and unpaid interest, with an amount equal to the net cash proceeds of certain equity offerings. At any time prior to May 15, 2021, NRG may redeem all or a part of the 2026 Senior Notes, at a redemption price equal to 100% of the principal amount, accrued and unpaid interest to the redemption date, plus a premium. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.625% of the note, plus interest payments due on the note from the date of redemption through May 15, 2021 computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after May 15, 2021, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
May 15, 2021 to May 14, 2022	103.625	%
May 15, 2022 to May 14, 2023	102.417	%
May 15, 2023 to May 14, 2024	101.208	%
May 15, 2024 and thereafter	100.000	%

2027 Senior Notes

At any time prior to July 15, 2019, NRG may redeem up to 35% of the aggregate principal amount of the 2027 Senior Notes, at a redemption price equal to 106.625% of the principal amount of the notes redeemed, plus accrued and unpaid interest, with an amount equal to the net cash proceeds of certain equity offerings. At any time prior to July 15, 2021 NRG may redeem all or a part of the 2027 Senior Notes, at a redemption price equal to 100% of the principal amount, accrued and unpaid interest to the redemption date, plus a premium. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 103.313% of the note, plus interest payments due on the note from the date of redemption through July 15, 2021 computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after July 15, 2021, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage	
July 15, 2021 to July14, 2022	103.313	%
July 15, 2022 to July 14, 2023	102.208	%
July 15, 2023 to July 14, 2024	101.104	%
July 15, 2024 and thereafter	100.000	%

2028 Senior Notes

At any time prior to January 15, 2021, NRG may redeem up to 35% of the aggregate principal amount of the 2028 Senior Notes, at a redemption price equal to 105.750% of the principal amount of the notes redeemed, plus accrued and unpaid interest, with an amount equal to the net cash proceeds of certain equity offerings. At any time prior to January 15, 2023 NRG may redeem all or a part of the 2028 Senior Notes, at a redemption price equal to 100% of the principal amount, accrued and unpaid interest to the redemption date, plus a premium. The premium is the greater of: (i) 1% of the principal amount of the notes; or (ii) the excess of the principal amount of the note over the following: the present value of 102.875% of the note, plus interest payments due on the note from the date of redemption through January 15, 2023 computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after January 15, 2023, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	Redemption Percentage
January 15, 2023 to January 14, 2024	102.875 %
January 15, 2024 to January 14, 2025	101.917 %
January 15, 2025 to January 14, 2026	100.958 %
January 15, 2026 and thereafter	100.000 %

Senior Credit Facility

On June 30, 2016, NRG replaced the previous senior credit facility, consisting of its Term Loan Facility and Revolving Credit Facility, with a new senior secured facility, or the Senior Credit Facility, which includes the following:

- A $1.9 billion term loan facility, or the 2023 Term Loan Facility, with a maturity date of June 30, 2023, which will pay interest at a rate of LIBOR plus 2.75%, with a LIBOR floor of 0.75%. The debt was issued at 99.50% of face value; the discount will be amortized to interest expense over the term of the loan. Repayments under the 2023 Term Loan Facility will consist of 0.25% of principal per quarter, with the remainder due at maturity. On January 24, 2017, NRG repriced the 2023 Term Loan Facility, reducing the interest rate margin by 50 basis points to LIBOR plus 2.25%, the LIBOR floor remains 0.75%. On March 21, 2018, NRG again repriced the 2023 Term Loan Facility, reducing the interest rate margin by 50 basis points to LIBOR plus 1.75% and reducing the LIBOR floor to 0.00%.

- A $289 million revolving senior credit facility, or the Tranche A Revolving Facility, with a maturity date of July 1, 2018 and a $2.2 billion revolving senior credit facility, or the Tranche B Revolving Facility, with a maturity date of June 30, 2021, which both pay interest at a rate of LIBOR plus 2.25%. On May 7, 2018, NRG entered into the third amendment agreement extending the maturity date of the Tranche A revolving facility to June 30, 2021, for the Tranche A accepting lender.

In accordance with the terms of the Credit Agreement, on October 5, 2018, the Company initiated an asset sale offer to purchase a portion of its Term Loan following the sale of NRG Yield and the Renewables Platform. The offer expired on November 5, 2018 and $260 million of Term Loan holders accepted the offer. As a result, the Company prepaid $155 million of Term Loans as part of its de-leveraging plan, as well as established an incremental first lien secured term loan facility under the Senior Credit Facility in the aggregate principal amount of $105 million on the same terms and conditions to stay within its debt reduction target. In addition, a $3 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $2 million.

In accordance with the terms of the credit agreement, upon the consummation of the sales of the South Central Portfolio and Carlsbad, the Company will initiate asset sale offers to purchase a portion of its Term Loan. The Company has one year from the dates of each sale to initiate the offer.

Tax Exempt Bonds

	As of December 31,		
	2018	2017	Interest Rate %
Amount in millions, except rates			
Indian River Power, tax exempt bonds, due 2040	$ 57	$ 57	6.000
Indian River Power LLC, tax exempt bonds, due 2045	190	190	5.375
Dunkirk Power LLC, tax exempt bonds, due 2042	59	59	5.875
City of Texas City, tax exempt bonds, due 2045	33	32	4.125
Fort Bend County, tax exempt bonds, due 2038	54	54	4.750
Fort Bend County, tax exempt bonds, due 2042	73	73	4.750
Total	$ 466	$ 465	

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Non-Recourse Debt
The following are descriptions of certain indebtedness of NRG's subsidiaries that are outstanding as of December 31, 2018. All of NRG's non-recourse debt is secured by the assets in the respective project subsidiaries as further described below.
Midwest Generation
On April 7, 2016, Midwest Generation, LLC, or MWG, entered into an agreement to sell certain quantities of unforced capacity that has cleared various PJM Reliability Pricing Model auctions to a trading counterparty for net proceeds of $253 million. MWG will continue to operate the applicable generation facilities and remains responsible for performance penalties and eligible for performance bonus payments, if any. Accordingly, MWG will continue to account for all revenues and costs as before; however, the proceeds will be recorded as a financing obligation while capacity payments by PJM to the counterparty will be reflected as debt amortization and interest expense through the end of the 2018/19 delivery year. MWG will amortize the upfront discount to interest expense, at an effective interest rate of 4.39%, over the term of the arrangement, through June 2019. As of December 31, 2018, $48 million was outstanding.
Agua Caliente Borrower I
On January 22, 2019, the lenders of the Agua Borrower I debt notified the Company of certain defaults under the financing agreement as it relates to the bankruptcy filing made by PG&E on January 29, 2019. PG&E is the offtaker of the underlying contracts, which are material. The financing was entered into along with Agua Caliente Borrower 2, LLC, a subsidiary of Clearway Energy Inc., which is joint and several to the parties. The Company is working with the lenders to determine a path forward.

Note 12 — Asset Retirement Obligations
The Company's AROs are primarily related to the environmental obligations related to nuclear decommissioning, ash disposal, site closures, and fuel storage facilities and future dismantlement of equipment on leased property. In addition, the Company has also identified conditional AROs for asbestos removal and disposal, which are specific to certain power generation operations.
See Note 6, Nuclear Decommissioning Trust Fund, for a further discussion of the Company's nuclear decommissioning obligations. Accretion for the nuclear decommissioning ARO and amortization of the related ARO asset are recorded to the Nuclear Decommissioning Trust Liability to the ratepayers and are not included in net income, consistent with treatment per ASC 980, Regulated Operations. Nuclear decommissioning ARO liabilities were $282 million and $269 million as of December 31, 2018 and 2017, respectively.
The following table represents the balance of ARO obligations as of December 31, 2018 and 2017, along with the additions, reductions and accretion related to the Company's ARO obligations for the year ended December 31, 2018:

	(In millions)
Balance as of December 31, 2017	$ 679
Revisions in estimates for current obligations	(27)
Additions	9
Spending for current obligations	(27)
Accretion — Expense	30
Accretion — Nuclear decommissioning	15
Balance as of December 31, 2018	$ 679

Note 13 — Benefit Plans and Other Postretirement Benefits
NRG sponsors and operates defined benefit pension and other postretirement plans.
NRG pension benefits are available to eligible non-union and union employees through various defined benefit pension plans. These benefits are based on pay, service history and age at retirement. Most pension benefits are provided through tax-qualified plans. NRG also provides postretirement health and welfare benefits for certain groups of employees. Cost sharing provisions vary by the terms of any applicable collective bargaining agreements.

NRG maintains two separate qualified pension plans, the NRG Pension Plan for Bargained Employees and the NRG Pension Plan. Employees of NRG participate in each of the pension plans, depending upon whether their employment is covered by a bargaining agreement.

NRG and GenOn entered into a Restructuring Support Agreement in which NRG agreed to retain GenOn's pension liability for service provided by GenOn employees prior to the completion of the GenOn reorganization. NRG determined that the retention of this liability was probable and recorded the estimated accumulated pension benefit obligation as of December 31, 2017 of $92 million, which reflects a $13 million contribution made by NRG to the plan in 2017, in other non-current liabilities with a corresponding loss from discontinued operations. NRG also agreed to retain the liability for GenOn's post-employment and retiree health and welfare benefits with the obligation capped at $25 million. NRG's obligation for both of these liabilities was revalued at GenOn's emergence from bankruptcy.

NRG expects to contribute $41 million to the Company's pension plans in 2019, of which $13 million relates to GenOn.

NRG Defined Benefit Plans

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

	Year Ended December 31, Pension Benefits		
	2018	2017	2016
	(In millions)		
Service cost benefits earned	$23	$26	$30
Interest cost on benefit obligation	44	43	43
Expected return on plan assets	(62)	(58)	(60)
Amortization of unrecognized net loss	—	4	2
Settlement/curtailment expense	7	—	—
Net periodic benefit cost	$12	$15	$15

	Year Ended December 31, Other Postretirement Benefits		
	2018	2017	2016
	(In millions)		
Service cost benefits earned	$1	$1	$ 2
Interest cost on benefit obligation	4	4	6
Amortization of unrecognized prior service credit	(10)	(9)	(5)
Amortization of unrecognized net (gain)/loss	—	(1)	—
Curtailment gain	(10)	—	—
Net periodic benefit (credit)/cost	$(15)	$(5)	$ 3

A comparison of the pension benefit obligation, other postretirement benefit obligations and related plan assets for NRG's plans on a combined basis is as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(In millions)			
Benefit obligation at January 1	$1,329	$1,241	$128	$128
Service cost	23	26	1	1
Interest cost	44	43	4	4
Plan amendments	17	—	(28)	(1)
Actuarial (gain)/loss	(95)	77	(6)	6
Employee and retiree contributions	—	—	3	3
Curtailment gain	(20)	—	(7)	—
Benefit payments	(76)	(58)	(12)	(13)
Benefit obligation at December 31	1,222	1,329	83	128
Fair value of plan assets at January 1	1,104	953	—	—
Actual return on plan assets	(80)	173	—	—
Employee and retiree contributions	—	—	3	3
Employer contributions	33	36	9	10
Benefit payments	(76)	(58)	(12)	(13)
Fair value of plan assets at December 31	981	1,104	—	—
Funded status at December 31 — excess of obligation over assets	$(241)	$(225)	$(83)	$(128)
Less: GenOn postretirement obligation[(a)]	—	—	—	38
Add: Retained obligation in bankruptcy proceeding[(a)]	—	—	—	(25)
Net obligation for NRG	$(241)	$(225)	$(83)	$(115)

(a) NRG's liability for GenOn's other postretirement benefit plans was capped at $25 million, with the final liability assumed determined as of GenOn's emergence from bankruptcy. As of December 31, 2017, the liability was $38 million so NRG's obligation was recorded at the $25 million cap. Upon emergence, the retained liability was $23 million, therefore NRG is obligated for the full retained liability of the plans.

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

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(In millions)			
Current liabilities	$—	$—	$ 7	$ 7
Less: GenOn other postretirement benefits	—	—	—	(3)
Total current liabilities	$—	$—	$ 7	$ 4
Non-current liabilities	$241	$225	$ 76	$ 121
Less: GenOn other postretirement benefits	—	—	—	(10)
Total non-current liabilities	$241	$225	$ 76	$ 111

Amounts recognized in NRG's accumulated OCI that have not yet been recognized as components of net periodic benefit cost were as follows:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(In millions)			
Net loss/(gain)	$90	$53	$ (9)	$ (4)
Prior service cost/(credit)	3	3	(53)	(37)
Total accumulated OCI	$93	$56	$ (62)	$ (41)
Less: GenOn (deconsolidated June 14, 2017)	—	(22)	—	10
Net accumulated OCI	$93	$34	$ (62)	$ (31)

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

	Year Ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(In millions)			
Net actuarial loss/(gain)	$47	$(37)	$ (5)	$ 6
Amortization of net actuarial (gain)/loss	—	(4)	—	1
Curtailment	(27)	—	2	—
Prior service credit	17	—	(28)	(1)
Amortization of prior service cost	—	—	10	9
Total recognized in OCI	$37	$(41)	$ (21)	$ 15
Less: GenOn (deconsolidated June 14, 2017)	—	15	$ —	$ 2
Net recognized in OCI	$37	$(26)	$ (21)	$ 17
Less: GenOn post deconsolidation net periodic benefit cost	—	—	—	1
Net periodic benefit cost/(credit)	12	15	(15)	(5)
Net recognized in net periodic pension cost/(credit) and OCI	$49	$(11)	$ (36)	$ 13

As a result of GenOn's deconsolidation during 2017, NRG reduced the loss recorded in other comprehensive income by $28 million related to GenOn's pension and other postretirement benefits.

The Company's estimated unrecognized loss and unrecognized prior service cost for NRG's pension plan that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is $4 million and $0 million, respectively. The Company's estimated unrecognized gain and unrecognized prior service credit for NRG's postretirement plan that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is less than $1 million and $13 million, respectively.

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

	As of December 31, Pension Benefits	
	2018	2017
	(In millions)	
Projected benefit obligation	$1,222	$1,329
Accumulated benefit obligation	1,188	1,255
Fair value of plan assets	981	1,104

NRG's market-related value of its plan assets is the fair value of the assets. The fair values of the Company's pension plan assets by asset category and their level within the fair value hierarchy are as follows:

	Fair Value Measurements as of December 31, 2018		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
	(In millions)		
Common/collective trust investment — U.S. equity	$ —	$ 183	$ 183
Common/collective trust investment — non-U.S. equity	—	53	53
Common/collective trust investment — non-core assets	—	117	117
Common/collective trust investment — fixed income	—	256	256
Short-term investment fund	12	—	12
Subtotal fair value	$ 12	$ 609	$ 621
Measured at net asset value practical expedient			
Common/collective trust investment — non-U.S. equity			70
Common/collective trust investment — fixed income			249
Common/collective trust investment — non-core assets			16
Partnerships/joint ventures			25
Total fair value			$ 981

	Fair Value Measurements as of December 31, 2017		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
	(In millions)		
Common/collective trust investment — U.S. equity	$ —	$ 256	$ 256
Common/collective trust investment — non-U.S. equity	—	66	66
Common/collective trust investment — non-core assets	—	178	178
Common/collective trust investment — fixed income	—	230	230
Short-term investment fund	5	—	5
Subtotal fair value	$ 5	$ 730	$ 735
Measured at net asset value practical expedient			
Common/collective trust investment — non-U.S. equity			94
Common/collective trust investment — fixed income			233
Partnerships/joint ventures			42
Total fair value			$ 1,104

In accordance with ASC 820, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trust investments is valued at fair value which is equal to the sum of the market value of all of the fund's underlying investments. Certain common/collective trust investments have readily determinable fair value as they publish daily net asset value, or NAV, per share and are categorized as Level 2.

Certain other common/collective trust investments and partnerships/joint ventures use NAV per share, or its equivalent, as a practical expedient for valuation, and thus have been removed from the fair value hierarchy table.
The following table presents the significant assumptions used to calculate NRG's benefit obligations:

	As of December 31,					
	Pension Benefits		Other Postretirement Benefits			
Weighted-Average Assumptions	2018	2017	2018		2017	
Discount rate	4.38%	3.71%	4.37	%	3.71	%
Rate of compensation increase	3.00%	3.00%	—	%	—	
Health care trend rate	—	—	7.8% grading to 4.5% in 2025		8.2% grading to 4.5% in 2025	

The following table presents the significant assumptions used to calculate NRG's benefit expense:

	As of December 31,					
	Pension Benefits			Other Postretirement Benefits		
Weighted-Average Assumptions	2018	2017	2016	2018	2017	2016
Discount rate	3.71%/4.04%	4.26%	4.52%	3.71%/4.08%	4.29 %	4.55 %
Expected return on plan assets	6.17 %	6.85%	6.65%	—	—	—
Rate of compensation increase	3.00 %	3.00%	3.00%	—	—	—
Health care trend rate	—	—	—	8.2% grading to 4.5% in 2025	7.0% grading to 5.0% in 2025	7.25% grading to 5.0% in 2025

NRG uses December 31 of each respective year as the measurement date for the Company's pension and other postretirement benefit plans. The Company sets the discount rate assumptions on an annual basis for each of NRG's defined benefit retirement plans as of December 31. The discount rate assumptions represent the current rate at which the associated liabilities could be effectively settled at December 31. The Company utilizes the Aon AA Above Median, or AA-AM, yield curve to select the appropriate discount rate assumption for each retirement plan. The AA-AM yield curve is a hypothetical AA yield curve represented by a series of annualized individual spot discount rates from 6 months to 99 years. Each bond issue used to build this yield curve must be non-callable, and have an average rating of AA when averaging available Moody's Investor Services, Standard & Poor's and Fitch ratings.

NRG employs a total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The Investment Committee reviews the asset mix periodically and as the plan assets increase in future years, the Investment Committee may examine other asset classes such as real estate or private equity. NRG employs a building block approach to determining the long-term rate of return assumption for plan assets, with proper consideration given to diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed income are preserved, consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonableness and appropriateness.

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

The target allocations of NRG's pension plan assets were as follows for the year ended December 31, 2018:

U.S. equity	22%
Non-U.S. equity	14%
Non-core assets	19%
U.S. fixed income	45%

Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S., non-U.S., global, and emerging market equities, as well as among growth, value, small and large capitalization stocks.

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

Asset Class	Index
U.S. equities	Dow Jones U.S. Total Stock Market Index
Non-U.S. equities	MSCI All Country World Ex-U.S. IMI Index
Non-core assets[(a)]	Various (per underlying asset class)
Fixed income securities	Barclays Capital Long Term Government/Credit Index & Barclays Strips 20+ Index

(a) Non-Core Assets are defined as diversifying asset classes approved by the Investment Committee that are intended to enhance returns and/or reduce volatility of the U.S. and non-U.S. equities. Asset classes considered Non-Core include, but may not be limited to: Emerging Market Equity, Emerging Market Debt, Non-US Developed Market Small Cap, High Yield Fixed Income, Real Estate, Bank Loans, Global Infrastructure and other Alternatives.

NRG's expected future benefit payments for each of the next five years, and in the aggregate for the five years thereafter, are as follows:

	Pension Benefit Payments	Other Postretirement Benefit: Benefit Payments	Other Postretirement Benefit: Medicare Prescription Drug Reimbursements
	(In millions)		
2019	$ 72	$ 7	$ —
2020	76	7	—
2021	79	7	—
2022	82	6	—
2023	85	6	—
2024-2028	418	26	1

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The impact of a one-percentage-point change in assumed health care cost trend rates is immaterial on total service and interest costs components but would have the following effect:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on postretirement benefit obligation	5	(4)

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in STP, as discussed further in Note 26, Jointly Owned Plants. STPNOC, which operates and maintains STP, provides its employees a defined benefit pension plan, as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. For the years ended December 31, 2018 and December 31, 2017, NRG reimbursed STPNOC $13 million and $8 million, respectively, for its contribution to the plans. In 2019, NRG expects to reimburse STPNOC $18 million for its contribution to the plans.

The Company has recognized the following in its statement of financial position, statement of operations and accumulated OCI related to its 44% interest in STP:

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(In millions)			
Funded status — STPNOC benefit plans	$(78)	$(76)	$(19)	$(24)
Net periodic benefit cost/(credit)	8	8	(7)	(3)

Other changes in plan assets and benefit obligations recognized in other comprehensive (loss)/income	(7)	(6)	2	5

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Defined Contribution Plans

NRG's employees are also eligible to participate in defined contribution 401(k) plans.
The Company's contributions to these plans were as follows:

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Company contributions to defined contribution plans	$ 28	$ 56	$ 55

Note 14 — Capital Structure

For the period from December 31, 2015 to December 31, 2018, the Company had 10,000,000 shares of preferred stock authorized and 500,000,000 shares of common stock authorized. The following table reflects the changes in NRG's common shares issued and outstanding for each period presented:

	Common		
	Issued	Treasury	Outstanding
Balance as of December 31, 2015	416,939,950	(102,749,908)	314,190,042
Shares issued under ESPP	—	609,094	609,094
Shares issued under LTIPs	643,875	—	643,875
Balance as of December 31, 2016	417,583,825	(102,140,814)	315,443,011
Shares issued under ESPP	—	560,769	560,769
Shares issued under LTIPs	739,309	—	739,309
Balance as of December 31, 2017	418,323,134	(101,580,045)	316,743,089
Shares issued under ESPP	—	175,862	175,862
Shares issued under LTIPs	1,965,752	—	1,965,752
Share repurchases	—	(35,234,664)	(35,234,664)
Balance as of December 31, 2018	420,288,886	(136,638,847)	283,650,039

Common Stock

The following table summarizes NRG's common stock reserved for the maximum number of shares potentially issuable based on the conversion and redemption features of the long-term incentive plans as of December 31, 2018:

Equity Instrument	Common Stock Reserve Balance
Long-term incentive plans	17,631,031

Common stock dividends — In the first quarter of 2016 the Company paid quarterly dividend of $0.145 per share, or $0.58 per share on an annualized basis. In 2016, as part of the 2016 Capital Allocation Program, the Company decreased its annual common stock dividend by 79% to $0.12 per share. The Company paid $0.030 dividend per common share for the second quarter of 2016 through the fourth quarter of 2018.

On January 23, 2019, NRG declared a quarterly dividend on the Company's common stock of $0.03 per share, or $0.12 per share on an annualized basis, payable on February 15, 2019, to stockholders of record as of February 1, 2019

Employee Stock Purchase Plan — Under the ESPP, eligible employees may elect to withhold up to 10% of their eligible compensation to purchase shares of NRG common stock at the lesser of 85% of its fair market value on the offering date or 85% of the fair market value on the exercise date. An offering date occurs each January 1 and July 1. An exercise date occurs each June 30 and December 31. Beginning January 2018, NRG suspended the ESPP. As of December 31, 2018, there remained 2,931,188 shares of treasury stock reserved for issuance under the ESPP.

Share Repurchases — In 2018, the Company's board of directors authorized the Company to repurchase $1.5 billion of its common stock. In addition, the Company's board of directors authorized in February 2019 an additional $1.0 billion share repurchase program to be executed in 2019.

The following table summarizes the shares repurchased under the 2018 program, including shares repurchased under two completed accelerated repurchase agreements:

Total number of shares purchased	Average price paid per share