UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of The Securities Exchange Act of 1934

May 7, 2020
Date of Report (date of earliest event reported)

NRG ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	001-15891	**41-1724239**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(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
N/A
(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.01	NRG	New York Stock Exchange

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

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.

☐

Item 8.01 Other Events

NRG Energy, Inc., or NRG or the Company, is an integrated power company built on dynamic retail brands with diverse generation assets. The Company's core business is the sale of electricity and natural gas to residential, commercial and industrial customers, supported by the Company's wholesale generation.

As part of perfecting the integrated model, in which the majority of the Company's generation serves its retail customers, the Company began managing its operations based on the combined results of the retail and wholesale generation businesses with a geographical focus in 2020. As a result, the Company changed its business segments from Retail and Generation to Texas, East and West/Other beginning in the first quarter of 2020. The Company's updated segment structure reflects how management currently makes financial decisions and allocates resources.

The Company's businesses are segregated as follows:

- Texas, which includes all activity related to customer operations in Texas (previously included in the Retail segment), plant operations in Texas (previously included in the Generation segment) and market operations in Texas (previously included in both the Retail and Generation segments);
- East, which includes the remaining activity related to customer operations (previously included in the Retail segment) and all activity related to plant operations in the East (previously included in the Generation segment) and market operations in the East (previously included in both the Retail and Generation segments);
- West/Other, which includes the following assets and activities (all previously included in the Generation segment, except for the Home Solar assets that were previously included in the Retail segment): (i) all activity related to plant and market operations in the West, (ii) activity related to the Cottonwood power plant that was sold to Cleco on February 4, 2019 and is being leased back until 2025, (iii) the remaining renewables activity, including the Company's equity method investments in Ivanpah Master Holdings, LLC and Agua Caliente, the remaining Home Solar assets and the NFL stadium solar generating assets, and (iv) activity related to the Company's equity method investment for the Gladstone power plant in Australia; and
- Corporate activities.

The vast majority of the Company's business is in Texas, where the Company's generation supply is fully integrated with its retail load. In the East, the Company's retail load is more disperse throughout the region and not fully integrated with the Company's generation supply due to the location of its power plants in that region. In the West, the Company's business is primarily generation supply.

The Company is filing this Current Report on Form 8-K to retrospectively revise historical information to correspond with this new segment structure. Included in Exhibit 99.1 to this Current Report on Form 8-K are retrospectively revised discussions within the following sections of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission ("SEC") on February 27, 2020 (the "2019 Form 10-K") in order to align with the new segment structure:

- Part I, Item 1 — Business;
- Part I, Item 2 — Properties;
- Part II, Item 6 — Selected Financial Data
- Part II, Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations; and
- Part IV, Item 15 — Exhibits, Financial Statement Schedules, including a revised Report of Independent Registered Public Accounting Firm, Note 1, *Nature of Business*, Note 2, *Summary of Significant Accounting Policies*, Note 3, *Revenue Recognition*, Note 4, *Acquisitions, Discontinued Operations and Dispositions*, and Note 19, *Segment Reporting*, to the Company's consolidated financial statements.

All other information in the 2019 Form 10-K remains unchanged. Also filed as Exhibit 99.2 to this Current Report on Form 8-K is unaudited quarterly financial information for the previously reported quarterly periods in the year ended December 31, 2019, which have been retrospectively revised to correspond with this new segment structure. The Consent of Independent Registered Public Accounting Firm is filed as Exhibit 23.1 to this Current Report on Form 8-K.

The changes in the reportable segment structure discussed above, as reflected in the information included in this Current Report on Form 8-K, affect only the manner in which the segment results were previously reported. This Current Report on Form 8-K does not revise nor restate the Company's previously reported consolidated financial statements for any period and does not modify or update the disclosures in any way other than as described above and set forth in the exhibits hereto. The information included in this Current Report on Form 8-K has not been otherwise updated for events or developments that occurred subsequent to the filing of the 2019 Form 10-K with the SEC on February 27, 2020. More current information is contained in the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2020 filed with the SEC on May 7, 2020 (the "first quarter 2020 10-Q"). The information in this Current Report on Form 8-K should be read in conjunction with the 2019 Form 10-K, the first quarter 2020 10-Q and other documents filed by the Company with the SEC or posted to the Company's corporate website at www.nrg.com subsequent to February 27, 2020.

Item 9.01 Financial Statements and Exhibits

Exhibits

Exhibit Number	Document
23.1	Consent of Independent Registered Public Accounting Firm
99.1	Items from Annual Report on Form 10-K for the year ended December 31, 2019, revised to update historical financial information and related disclosures to reflect a change in the Company's segment structure: Part 1, Item 1 - Business; Part I, Item 2 - Properties; Part II, Item 6 - Selected Financial Data; Part II, Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations; and Part IV, Item 15 - Exhibits, Financial Statement Schedules
99.2	Supplemental quarterly financial data for the year ended December 31, 2019 (unaudited)
101	The revised financial information from the Annual Report on Form 10-K for the year ended December 31, 2019 included in Part IV, Item 15 - Exhibits, Financial Statement Schedules of Exhibit 99.1 of this Form 8-K, formatted in iXBRL (Inline Extensible Business Reporting Language)
104	Cover Page Interactive Data File - the cover page XBRL tags are embedded within the iXBRL document

SIGNATURES

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

NRG Energy, Inc.
(Registrant)

By: /s/ MAURICIO GUTIERREZ

Mauricio Gutierrez
Chief Executive Officer

Date: May 7, 2020

Consent of Independent Registered Public Accounting Firm

The Board of Directors
NRG Energy, Inc.:

We consent to the incorporation by reference in the registration statement Numbers 333-217595, 333-197882, 333-185501, 333-182379, 333-171318, 333-151992, 333-135973 and 333-114007 on Form S-8 of NRG Energy, Inc. (the Company) of our reports dated February 27, 2020, except as to Notes 1,2,3,4 and 19 as it relates to operating segments, which are as of May 7, 2020, with respect to the consolidated balance sheets of the Company as of December 31, 2019 and 2018, 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, 2019, and the related notes and financial statement schedule (collectively, the consolidated financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2019, which reports appear in the December 31, 2019 annual report on Form 10-K and in the Form 8-K dated May 7, 2020 of the Company.

Our report dated February 27, 2020, except as to Notes 1,2,3,4 and 19 as it relates to operating segments, which are as of May 7, 2020, on the consolidated financial statements refers to changes in accounting principle, the Company's adoption of Topic 842, *Leases*, and Topic 606, *Revenue from Contracts with Customers.*

Our report dated February 27, 2020 on the effectiveness of internal control over financial reporting as of December 31, 2019, contains an explanatory paragraph that states our audit of the Company's internal control over financial reporting excluded Stream Energy.

/s/ KPMG LLP

Philadelphia, Pennsylvania

May 7, 2020

Exhibit 99.1

Excerpts of the NRG Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2019 retrospectively revised to reflect change in segment structure

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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 (as of December 31, 2018) term loan facility due 2023, a component of the Senior Credit Facility, which was repaid during the second quarter of 2019
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
CCR	Coal Combustion Residuals
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.
Convertible Senior Notes	As of December 31, 2019, consists of NRG’s $575 million unsecured 2.75% Convertible Senior Notes due 2048
Cottonwood	Cottonwood Generating Station, a 1,153 MW natural gas-fueled plant
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
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
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
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESCO	Energy Service Companies
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
FTRs	Financial Transmission Rights
GAAP	Generally accepted accounting principles 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
Guam	NRG's wholly owned subsidiary NRG Solar Guam, LLC that was sold during the first quarter of 2019
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
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
MMDth	Million Dekatherms
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
NYSDEC	New York State Department of Environmental Conservation
NYSPSC	New York State Public Service Commission

OCI/OCL	Other Comprehensive Income/(Loss)
ORDC	Operating Reserve Demand Curve
Peaking	Units expected to satisfy demand requirements during the periods of greatest or peak load on the system
PER	Peak Energy Rent
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
RCE	Residential Customer Equivalent, a single RCE represents 10,000 kWh of electricity
RCRA	Resource Conservation and Recovery Act of 1976
RECs	Renewable Energy Certificates
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, 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
Revolving Credit Facility	The Company's $2.6 billion revolving credit facility, a component of the Senior Credit Facility, due 2024 was amended on May 28, 2019
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. The 2023 Term Loan Facility was repaid in the second quarter of 2019

Senior Notes	As of December 31, 2019, NRG's $3.8 billion outstanding unsecured senior notes consisting of $1.0 billion of the 7.25% senior notes due 2026, $1.23 billion of the 6.625% senior notes due 2027, $821 million of 5.75% senior notes due 2028 and $733 million of the 5.25% senior notes due 2029
Senior Secured Notes	As of December 31, 2019, NRG’s $1.1 billion outstanding Senior Secured First Lien Notes consists of $600 million of the 3.75% Senior Secured First Lien Notes due 2024 and $500 million of the 4.45% Senior Secured First Lien Notes due 2029
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 owned and operated a portfolio of generation assets consisting of Bayou Cove, Big Cajun-I, Big Cajun-II, Cottonwood and Sterlington, was sold on February 4, 2019. NRG is leasing back the Cottonwood facility through May 2025
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
TDSP	Transmission/distribution service provider
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
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 integrated power company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to customers by producing and selling electricity and related products and services in major competitive power markets in the U.S. and Canada in a manner that delivers value to all of NRG's stakeholders. NRG is a customer-driven business focused on perfecting the integrated model by balancing retail load with generation supply within its deregulated markets. The Company sells energy, services, and innovative, sustainable products and services directly to retail customers under the brand names NRG, Reliant, Green Mountain Energy, Stream, and XOOM Energy, as well as other brand names owned by NRG, supported by approximately 23,000 MW of generation as of December 31, 2019. NRG was incorporated as a Delaware corporation on May 29, 1992.

NRG divested non-core businesses including, among others: (i) NRG Yield, Inc. and the Renewables Platform during 2018; and (ii) the South Central Portfolio during 2019.

The Company previously owned 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.

Since 2017, the Company has been executing its three-year Transformation Plan, which includes targets related to operations and cost excellence, portfolio optimization, and capital structure and allocation enhancement. See Item 7 – *Management's Discussion and Analysis of Financial Conditions and Results of Operations* for further discussion.

Strategy

NRG's strategy is to maximize stockholder value through the safe production and sale of reliable power to its customers in the markets it serves, while positioning the Company to provide innovative solutions to the end-use energy customer. This strategy is intended to enable the Company to optimize its integrated model to generate stable and predictable cash flow, significantly strengthen earnings and cost competitiveness, and lower risk and volatility.

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) offering innovative and renewable energy solutions for customers; (iii) excellence in operating performance of its existing assets; (iv) optimal hedging of NRG's net retail and generation positions; and (v) engaging in disciplined and transparent capital allocation.

Sustainability is an integral piece of NRG's strategy and ties directly to business success, reduced risks and brand value. On September 24, 2019, NRG announced the acceleration of its science-based GHG emissions reduction goals to align with prevailing climate science, limiting warming to a 1.5 degree Celsius scenario. Under its new GHG emissions reduction timeline, NRG is targeting to achieve a 50% reduction by 2025 and net-zero emissions by 2050, from a 2014 baseline.

Business Overview

The Company's core business is the sale of electricity and natural gas to residential, commercial and industrial customers, supported by the Company's wholesale generation.

As part of perfecting the integrated model, in which the majority of the Company's generation serves its retail customers, the Company began managing its operations based on the combined results of the retail and wholesale generation businesses with a geographical focus in 2020. As a result, the Company changed its business segments from Retail and Generation to Texas, East and West/Other beginning in the first quarter of 2020. The Company's updated segment structure reflects how management currently makes financial decisions and allocates resources.

The Company's businesses are segregated as follows:

- Texas, which includes all activity related to customer, plant and market operations in Texas;
- East, which includes the remaining activity related to customer operations and all activity related to plant and market operations in the East;
- West/Other, which includes the following assets and activities: (i) all activity related to plant and market operations in the West, (ii) activity related to the Cottonwood power plant that was sold to Cleco on February 4, 2019 and is being leased back until 2025, (iii) the remaining renewables activity, including the Company's equity method investments in Ivanpah Master Holdings, LLC and Agua Caliente, the remaining Home Solar assets and the NFL stadium solar

generating assets, and (iv) activity related to the Company’s equity method investment for the Gladstone power plant in Australia; and

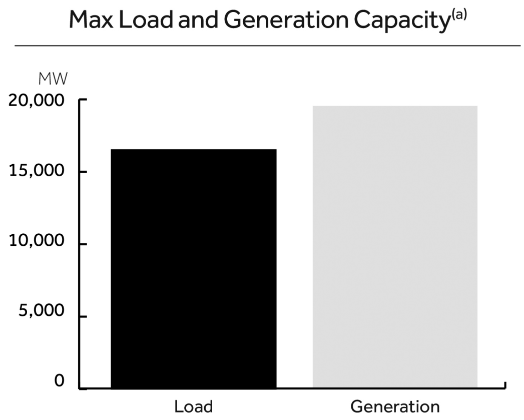
- Corporate activities.

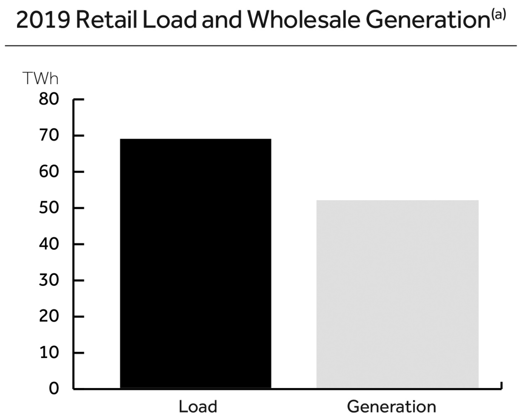
The vast majority of the Company’s business is in Texas, where the Company’s generation supply is fully integrated with its retail load. In the East, the Company’s retail load is more disperse throughout the region and not fully integrated with the Company’s generation supply due to the location of its power plants in that region. In the West, the Company’s business is primarily generation supply.

The Company’s integrated model consists of three core functions: Customer Operations, Market Operations and Plant Operations, which directly support each other in each geographic region. The Company’s integrated model provides the advantage of being able to supply the Company’s retail customers with electricity from the Company’s assets, which reduces the need to sell power to and buy power from other institutions and intermediaries, resulting in stable earnings and cash flows, lower transaction costs and less credit exposure. The integrated model also results in a reduction in actual and contingent collateral through offsetting transactions, thereby minimizing transactions with third parties.

NRG provides energy and related services to residential, industrial and commercial customers at either fixed, indexed or variable prices through various brands and sales channels across the U.S. and Canada. Residential and small commercial (Mass market) customers typically contract for terms ranging from one month to five years, while industrial and large commercial (C&I) contracts are often between one year and five years in length. NRG sold approximately 69 TWhs of electricity and 23 MMDth of natural gas in 2019 and served approximately 3.7 million customers as of December 31, 2019, making it one of the largest competitive energy retailers in the U.S. In any given year, the quantity of TWhs and MMDth sold can be affected by weather, economic conditions and competition. As of the end of 2019, NRG had recurring electricity and/or natural gas sales in 19 U.S. states, the District of Columbia, and 2 provinces in Canada. NRG's retail brands, collectively, have the largest share of competitively served residential electric customers in Texas and nationwide.

The charts below illustrate NRG's U.S. retail capabilities, power generation and net capacity as of and for the year ended December 31, 2019:





(a) Excludes International, West, and Renewables.

Customer Operations

Customer Operations is responsible for growing and retaining the customer base and delivering an outstanding customer experience. This includes acquisition and retention of all of NRG’s residential, small commercial, government and commercial & industrial customers. NRG employs a multi-brand strategy that leverages a wide array of sales and partnership channels, direct face-to-face sales channels, call centers, websites, and brokers. Go-to-market activities include market strategy planning and development, product innovation, offer design, campaign execution, marketing and creative services, and selling. Customer portfolio maintenance and retention activities include fulfillment, billing, payment processing, collections, customer service, issue resolution, and contract renewals. Throughout all Customer Operations activities, the customer experience is kept at the forefront to inform decision-making and optimize retention, while creating supporters and advocates for NRG’s brands in the market.

Product Offerings

NRG sells a variety of products to residential and small commercial customers including retail electricity and energy management, natural gas, home security, line and surge protection products, HVAC installation, repair and maintenance, carbon offsets, back-up power stations, portable power, portable solar and portable lighting. Mass market customers make purchase decisions based on a variety of factors, including price, incentive, customer service, brand, innovative offers/features and referrals from friends and family. Through its broad range of service offerings and value propositions, NRG is able to attract, retain, and increase the value of its customer relationships. NRG's brands are recognized for exemplary customer service, innovative smart energy and technology product offerings, and environmentally-friendly solutions.

The Company also provides retail services, including demand response, commodity sales, energy efficiency and energy management solutions to C&I customers. The Company is an integrated provider of supply and distributed energy resources and focuses on distributed products and services as businesses seek greater reliability, cleaner power and/or other benefits that they cannot obtain from the grid. These solutions include system power, distributed generation, renewable 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 C&I customers. In 2019, the Company sold approximately 20 TWhs of electricity to C&I customers and managed approximately 2,000 MWs of demand response positions across its portfolio.

Market Operations

Market Operations has two primary objectives: (i) to supply load to our customers in the most cost-efficient manner; and (ii) to maximize the value of any excess generation after satisfying the Company’s customer load requirements. These objectives are intended to reduce supply costs and maximize earnings with predictable cash flows.

To meet these objectives, NRG enters into supply, power sales and hedging arrangements via a wide range of products and contracts, including (i) renewable PPAs, (ii) capacity auctions and other contracted revenue sources, (iii) fuel supply and transportation contracts, and (iv) 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.

Renewable PPAs

During 2019, NRG began procuring mid to long-term renewable generation through power purchase agreements. As of December 31, 2019, NRG has entered into PPAs in Texas totaling approximately 1,600 MWs with third-party project developers and other counterparties. The average tenor of these agreements is ten years. The Company expects to continue evaluating and executing agreements, such as these, that support the needs of the business.

Capacity and Other Contracted Revenue Sources

NRG's revenues and cash flows, primarily in the East and West, 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.

The Company's largest sources of capacity revenues are capacity auctions in PJM, ISO-NE and NYISO. Both PJM and ISO-NE operate a pay-for-performance model where capacity payments are modified based on real-time performance and 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 respective generation assets. 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

- *2023/2024 ISO-NE Auction Results* - On February 5, 2020 ISO-NE announced the results of its 2023/2024 forward capacity auction. NRG cleared 784 MW of capacity. NRG's expected capacity revenues from the auction for the 2023/2024 delivery year are approximately $18 million.
- *PJM Auction Results* — PJM announced during 2019 it was suspending all auction deadlines relating to Base Residual Auctions for 2022/2023 and 2023/2024 delivery year, consistent with FERC’s July 25, 2019 Order. Refer to the Capacity Market Reforms Filing discussion within the Regional Regulatory Developments section below for further discussion.

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.

Fuel Supply and Transportation

NRG's fuel requirements consist of various forms of fossil fuel and nuclear fuel. The prices of fossil fuels can be 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 business and fuel products used. NRG's primary fuel requirements consist of the following:

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 as the dispatch is highly unpredictable. The Company contracts for natural gas storage services, as well as natural gas transportation services to deliver natural gas when needed.

Coal — The Company believes it is adequately hedged, using forward coal supply agreements, for its domestic coal consumption for 2020. NRG actively manages its coal requirements based on forecasted generation, market volatility and its inventory on site. As of December 31, 2019, NRG had purchased forward contracts to provide fuel for approximately 58% of the Company's expected requirements for 2020 and 2021 per the table below. NRG purchased approximately 17 million tons of coal in 2019, almost all of which was Powder River Basin coal. For fuel transport, NRG has entered into various rail transportation and rail car lease agreements with varying tenures that will 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 for 2020 and 2021 that have been purchased forward as of December 31, 2019:

	Percentage of Company's Requirement
2020	100 %
2021	16 %

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 that is 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 2017, STPNOC has begun to review a second phase of fuel purchasing.

Natural Gas Derivative Instruments and Other Financial Instruments

NRG also trades electric power, natural gas and related commodity and financial products, including forwards, futures, options and swaps.

Plant Operations

The Company owns a diversified power generation portfolio with approximately 23,000 MW of fossil fuel, nuclear and renewable generation capacity at 32 plants as of December 31, 2019. 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 continually evaluates its generation portfolio to focus on asset optimization opportunities and the locational value of its generation assets in each of the markets where the Company participates, as well as opportunities for the development of new generation.

The following table summarizes NRG's generation portfolio as of December 31, 2019:

	(In MW)[a]			
Type	**Texas**	**East**	**West/Other**	**Total**
Natural gas	4,759	2,686	2,308	9,753
Coal	4,174	3,140	605	7,919
Oil	—	3,600	—	3,600
Nuclear	1,126	—	—	1,126
Utility Scale Solar	—	—	321	321
Battery Storage & Distributed Solar[b]	2	—	60	62
Total generation capacity	10,061	9,426	3,294	22,781

(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 Distributed Solar figure includes the aggregate production capacity of installed and activated residential solar energy systems

Plant Operations is responsible for operating the Company's generation facilities at the highest standards of safety and reliability, and includes (i) operations and maintenance, (ii) asset management, and (iii) development, engineering and construction.

Operations & Maintenance

NRG operates and maintains its generation portfolio, as well as approximately 8,100 MW of additional coal and natural gas generation capacity at 17 plants operated on behalf of third parties as of December 31, 2019 using prudent industry practices for the safe, reliable and economic generation of electricity in compliance with all local, state and federal requirements. The Company follows a consistent set of operating requirements, including a solid base of training, required adherence to specific safety and environmental limits, procedure and checklist usage, and the implementation of continuous process improvement through incident investigations.

NRG uses best-in-class maintenance practices for preventive, predictive, and corrective maintenance planning. The Company’s strategic planning process evaluates equipment condition, performance, and obsolescence to support the development of a comprehensive work scope and schedule for long-term performance.

Asset Management

NRG manages all aspects of its generation portfolio to optimize the lifecycle value of the assets, consistent with the Company’s goals. The Company evaluates capital projects required for continued operation and strategic enhancement of the assets, provides quality assurance on capital outlays, and assesses the impact of rules, regulations, and laws on business profitability. In addition, the Company manages its long-term contracts, power purchase agreements, and real estate holdings and provides third party asset management services.

Development, Engineering & Construction

NRG develops, engineers and executes major plant modifications, “new build” generation and energy storage projects that enhance the value of its generation portfolio and provide options to meet generation growth needs in the retail markets we serve, in accordance with the Company’s strategic goals. Projects have included gas-fired generation development and construction, coal to gas conversions, grid scale energy storage development, grid scale renewable construction, and asset demolition, remediation and reclamation work.

Operational Statistics

The following statistics represent the Company's retail customer count, load and contract mix:

	Years ended December 31,		
	2019	2018	2017
Sales volumes *(in GWh)*			
Mass Market electricity - Texas	38,958	37,846	36,169
Mass Market electricity - East	9,918	7,968	6,221
C&I electricity - Texas	18,976	20,192	19,586
C&I electricity - East	1,214	984	814
Total Load	69,066	66,990	62,790
Customer count - Electricity *(in thousands)*			
Mass Market - Texas [(a)]			
Average retail	2,358	2,209	2,177
Ending retail	2,450	2,318	2,188
Mass Market - East			
Average retail	990	790	675
Ending retail	1,070	903	673
[(a)] Includes customers of non-electric services			
Customer count - Natural gas - East *(in thousands)*			
Average retail Mass Market	122	64	11
Ending retail Mass Market	158	99	15
Customer contract mix			
Fixed	67 %	65 %	70 %
Variable	24 %	25 %	22 %
Indexed	9 %	10 %	8 %
	100 %	100 %	100 %

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 generation portfolio, including leased facilities and those accounted for through equity method investments, for the years ended December 31, 2019 and 2018:

	Year Ended December 31, 2019				
			Fossil and Nuclear Plants [a]		
	Net Owned Capacity (MW)	Net Generation (In thousands of MWh) [a]	Annual Equivalent Availability Factor	Average Net Heat Rate BTU/kWh	Net Capacity Factor
Texas	10,061	37,995	83.3 %	10,542	43.2 %
East	9,426	6,913	81.7 %	11,917	8.3 %
West/Other [b][c]	3,294	9,462	79.9 %	6,751	51.4 %

	Year Ended December 31, 2018				
			Fossil and Nuclear Plants [a]		
	Net Owned Capacity (MW)	Net Generation (In thousands of MWh) [a]	Annual Equivalent Availability Factor	Average Net Heat Rate BTU/kWh	Net Capacity Factor
Texas	10,161	38,214	85.2 %	10,423	44.7 %
East	9,447	10,119	81.6 %	11,532	11.6 %
West/Other [b][c]	3,650	10,970	89.6 %	7,314	55.3 %

(a) Net generation excludes equity method investments
(b) Includes the Sherbino and Guam facilities that were sold in 2019
(c) 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, 2019, 2018 and 2017 is shown below:

	Net Generation		
(In thousands of MWh)	**2019**	**2018**	**2017**
Texas			
Coal	21,985	24,781	24,757
Gas	6,315	4,415	4,428
Nuclear [a]	9,695	9,018	9,509
Total Texas	37,995	38,214	38,694
East			
Coal	4,435	7,965	8,403
Oil	209	544	319
Gas	2,269	1,610	1,222
Total East	6,913	10,119	9,944
West/Other			
Gas	9,450	10,187	9,727
Renewables	12	783	1,667
Total West/Other	9,462	10,970	11,394

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

Competition

While there has been consolidation in the competitive retail space over the past few years, there is still considerable competition for customers. In Texas, there is healthy competition in deregulated areas and customers can choose providers based on the most appealing offers. Outside of Texas, electricity retailers compete with the incumbent utilities, in addition to other retail electric providers, which can inhibit competition, depending on the market rules of the state. Most markets have more than 30 retailers competing for customers, while Texas has more than 50 retailers. There is a high degree of fragmentation, with both large and small competitors offering a range of value propositions, including value, rewards, and sustainability.

Wholesale generation is highly fragmented and diverse in terms of industry structure by region. As such, there is a wide variation in terms of the capabilities, resources, nature and identities of the Company’s competitors 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.

Seasonality and Price Volatility

The sale of electric power to retail customers is 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 have a material impact. The rates charged to retail customers may be impacted by fluctuations in total power prices and market dynamics, such as the price of natural gas, transmission constraints, competitor actions, and changes in market heat rates.

Annual and quarterly operating results of the Company's generation portfolio 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 regions in which the Company operates.

Market Framework

NRG sells energy and related services, as well as portable power and battery solutions, to customers across the country. In most of the states that have introduced retail consumer choice, NRG competitively offers electricity, natural gas, portable power and other value-enhancing services to customers. Each retail consumer choice state establishes its own retail competition laws and regulations, and the specific operational, licensing, and compliance requirements vary by state. 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 may be impacted by the rules, regulations, market structure and communication requirements from public utility commissions in each state across the country.

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. 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 business in Texas is subject to standards and regulations adopted by the PUCT and ERCOT[a], including the requirement for retailers to be certified by the PUCT in order to contract with end-users to sell electricity. 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. The PUCT directed ERCOT to implement changes in 2019. The first phase became effective on March 1, 2019 and the second phase will become effective on March 1, 2020. The majority of the retail load in the ERCOT market region is served by competitive retail suppliers, except certain areas that have not opted into competitive consumer choice and are served by municipal utilities and electric cooperatives.

East

While most of the states in the East region have introduced some level of retail consumer choice for electricity and/or natural gas, the incumbent utilities currently provide default service in most of the states and as a result typically serve the majority of residential customers. NRG’s retail activities in the East are subject to standards and regulations adopted by the ISOs and state public utility commissions, including the requirement for retailers to be certified in each state in order to contract with end-users to sell electricity.

(a) The Cottonwood facility is located in Deweyville, Texas, but operates in the MISO market

NRG's power plants 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. 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 capacity 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. Additionally, bidding rules allow for the incorporation of a risk premium into generator bids.

West

In the West region of the U.S., NRG operates a fleet of natural gas-fired power plants 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. Agua Caliente Borrower 1 LLC, along with Agua Caliente Borrower 2 LLC, which is owned by Clearway Energy Inc., were party to a back-leverage financing related to the Agua Caliente project, which was repaid in 2019. On January 29, 2019, PG&E Corp. and subsidiary utility PG&E filed for Chapter 11 bankruptcy protection. For further discussion see Energy Regulatory Matters, Item 15 — Note 13, *Debt and Finance Leases*, and Item 15 — Note 17, *Investments Accounted for by the Equity Method and Variable Interest Entities*, to the Consolidated Financial Statements.

Regulatory Matters

As participants in wholesale and retail energy markets and owners of power plants, 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 generation 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

PG&E Corporation Bankruptcy Filing — On January 18, 2019, NextEra Energy, Inc., 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. Separately, the PG&E bankruptcy court ruled on June 7, 2019 that it does not share concurrent jurisdiction with FERC and has unilateral discretion to address the disposition of wholesale power contracts, which ruling was appealed by FERC and various counterparties to such contracts. On June 26, 2019, PG&E appealed the FERC order that was issued on January 25, 2019. Both sets of appeals are currently pending before the Court of Appeals for the Ninth Circuit and the issue of jurisdiction over wholesale power contracts remains in litigation.

On September 9, 2019, PG&E filed a plan of reorganization that would assume all power purchase agreements, including those held by the Agua Caliente project and two of the Ivanpah units. On October 17, 2019, a group of unsecured noteholders filed a competing plan of reorganization that would also assume all power purchase agreements, including those held by the Agua Caliente project and the two Ivanpah units.

On January 22, 2020, PG&E announced that it had reached an agreement with certain noteholder plan proponents and, on January 31, 2020, the PG&E plan was amended to provide for the eventual implementation of such settlement. On February 4, 2020, the Bankruptcy Court approved such settlement, and the noteholders have accordingly agreed to support the PG&E plan. On February 5, 2020, the noteholders caused the noteholder plan to be withdrawn. There are many conditions that must be satisfied before the PG&E plan and assumption of the power purchase agreements can become effective, including, but not limited to, approvals by various classes of creditors, the Bankruptcy Court, and the CPUC. A hearing before the Bankruptcy Court to consider whether the PG&E plan will be approved and confirmed is currently expected to occur on May 29, 2020.

State Energy Regulation

State Out-Of-Market Subsidy Proposals — NRG has opposed efforts to provide out-of-market subsidies for nuclear generators and intends to continue opposing them in the future. Nuclear subsidy programs have either been implemented, are in the process of being implemented, or have been introduced for discussion in Connecticut, Illinois, New Jersey, New York, Ohio and Pennsylvania. NRG and others were unsuccessful in challenging the legality of the subsidies in Illinois and New York, and the U.S. Supreme Court has declined to review the lower court decisions. Through our PJM trade organization, NRG is also currently participating in an appeal of NJBPU's Order regarding ZECs.

Illinois Legislature Considers Changes to the Generator Business Model — In Illinois, in addition to legislation to provide more subsidies to nuclear power plants in the state, the Legislature is also considering several bills that may affect NRG’s wholesale and retail revenues, including a bill that would replace the PJM capacity market with a state-run capacity market. NRG continues to oppose the ongoing legislative effort and supports a competitive clean energy market design that would competitively reduce greenhouse gas emission through the procurement of clean energy resources without sacrificing the consumer benefits of the competitive PJM market design.

New York State Climate Leadership and Community Protection Act — The New York State Legislature enacted climate change legislation establishing by 2030, 70 percent of the state's energy will be generated by renewables and by 2040, the state's entire electric system must be zero-emitting. The law includes a provision that the NYSPSC may temporarily suspend or modify the obligations under its program if it finds that the program impedes safe and adequate electric service, likely impairs "existing obligations and agreements," and/or increases consumer late payments or service disconnections. The legislation includes provision for offsets, including carbon capture and sequestration, but electric generation sources are not eligible to participate in the offsets mechanism.

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 24, *Regulatory Matters,* to the Consolidated Financial Statements.

East/West

PJM

Capacity Market Reforms Filing — On December 19, 2019, FERC issued an order on the pending proposals to reform the PJM market to mitigate subsidized resources in the capacity market. FERC directed PJM to apply the Minimum Offer Price Rule, or MOPR, to new and existing resources receiving state subsidies and subject them to default offer floor prices in their capacity bids. The Order provided for various category specific exemptions to the MOPR, as well as a unit specific exemption, which permits any resource that can justify an offer lower than the default offer price floor to submit such capacity bids to PJM for review. As part of the December 19, 2019 FERC Order, FERC gave PJM 90 days to make a compliance filing and submit tariff language to reflect the requirements of the Order and directed PJM to include in this filing a timetable for when it proposes to hold the previously postponed Base Residual Auctions for the 2022/2023 and 2023/2024 delivery years. Multiple parties filed for rehearing. Subjecting subsidized resources to default offer floors in the capacity market should protect the market from further price suppression. The impact of these changes on capacity markets outcomes is dependent on, among other factors, bidding behavior, load forecast changes, new resource entry, and existing resource exit.

PJM's Operating ORDC Filing — On March 29, 2019, PJM proposed energy and reserve market reforms to enhance price formation in reserve markets, which includes modifying its ORDC and aligning market-based reserve products in Day-Ahead and Real-Time markets. The matter is pending at FERC. If the proposal were approved as filed, energy and reserve market prices could increase.

Independent Market Monitor Market Seller Offer Cap Complaint — On February 21, 2019, the Independent Market Monitor filed a complaint alleging that the current Market Seller Offer Cap is too high. On April 9, 2019, PJM filed its answer arguing that as a threshold matter the Independent Market Monitor is not authorized to file a complaint against PJM and among other things, that the Market Monitor failed to support its claim that the expected number of performance assessment hours used to calculate the cap is overstated. The Company’s trade organization filed a protest in the docket echoing PJM’s concerns. The

Market Monitor subsequently filed answers in the docket and the docket remains pending. If the request is granted, default market offer caps could be lower.

PJM's Fast Start Pricing Filing — On April 19, 2019, FERC ordered PJM to implement fast start pricing because it found that the existing fast start pricing practices are unjust and unreasonable because they do not allow prices to reflect the marginal cost of serving load. PJM made its compliance filing on August 30, 2019. On January 23, 2020, FERC issued an order holding the proceeding in abeyance until July 31, 2020, to allow PJM to consider changes to address FERC's concern about a mismatch between dispatch and pricing. The changes could provide more accurate pricing to reflect the marginal cost of serving load.

New England

ISO-NE Retention of Mystic Units — ISO-NE is currently engaged in a proceeding 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, and also ordered ISO-NE to provide a long-term market-based solution for fuel security. On January 2, 2019, multiple parties filed for rehearing. The motions for rehearing are pending at FERC. On January 10, 2020, FERC rejected Exelon's request to have the option to terminate the second year of its two-year cost of service agreement for Mystic units 8 and 9. The outcome of this matter may affect future capacity market prices.

ISO-NE Inventoried Energy Compensation Proposal — On March 25, 2019, ISO-NE proposed an interim measure to address near-term fuel security concerns. The proposal would provide payment for inventoried energy during winter months. NRG protested, among other things, the payment rate proposed by the ISO for inventoried energy. After ISO-NE supplemented its filings due to a deficiency notice from FERC, NRG filed comments to ISO-NE's response on June 27, 2019. On August 6, 2019, FERC issued a notice stating that due to lack of quorum, ISO-NE's proposal became effective by operation of law. Multiple parties filed for rehearing. Those rehearings were denied. Subsequently, multiple parties filed an appeal of FERC's Order to the Court of Appeals for the D.C. Circuit. The case is pending. ISO-NE's proposal will affect future capacity market prices and the compensation fuel secure units receive.

Connecticut Department of Energy and Environmental Protection Integrated Resource Plan Proceeding — In Connecticut's ongoing proceeding related to its Integrated Resource Plan, the Connecticut Department of Energy and Environmental Protection issued a notice of technical meeting and opportunity for public comment on January 8, 2020 seeking comment on two issues: (1) the compatibility of state goals and those of ISO-NE and (2) the possibility of alternative market designs that would be more in line with the state's goals. On January 22, 2020, NRG presented its thoughts and on February 5, 2020, NRG filed comments advocating for competitive markets and proposed its competitive clean energy market design. On February 28, 2020, the Connecticut Departments of Energy and Environmental Protection will hold a second technical meeting.

New York

New York State Public Service Commission Retail Energy Market Proceedings — On February 23, 2016, the NYSPSC issued an order referred to as the Retail Reset Order. Among other things, the Retail Reset Order placed a price cap on energy supply offers and imposed burdensome new regulations on customers. Various parties have challenged the NYSPSC's authority to regulate prices charged by competitive suppliers. On May 9, 2019 the New York Court of Appeals, the state's highest tribunal, issued a decision affirming the NYSPSC's authority to regulate ESCO's prices as a condition of access to the utilities' infrastructure. In conjunction with the court challenge, the NYSPSC also noticed an evidentiary proceeding. On December 12, 2019, the NYSPSC issued an order adopting changes to the retail access energy market based on the record in the evidentiary proceeding. The Order limits ESCO offers to three compliant products: guaranteed savings from the utility default rate, a fixed term capped at 5% of the rolling 12-month average utility default rate, or NY-sourced renewable energy that is at least 50% greater than the prevailing NY Renewable Energy Standard for load serving entities. The Order also establishes new ESCO eligibility criteria and certification process, as well as re-certification of current ESCOs. The NYSPSC ordered compliance effective February 10, 2020. On January 13, 2020, multiple parties filed motions for rehearing and a stay of the Order. On January 17, 2020, NRG filed a request for a 90-day extension of the February 10, 2020 effective date, and, on January 22, 2020, the NYSPSC granted an extension for compliance to May 11, 2020. The limited offerings imposed by the Order, as issued, may negatively impact the retail business.

New York State Public Service Commission Resource Adequacy Proceeding — On August 8, 2019, the NYSPSC established an investigation into New York's resource adequacy market design. On November 8, 2019, NRG filed comments and recommendations, specifically putting forth NRG's Forward Clean Energy Market Proposal, that would allow New York to maintain a reliable system while advancing its environmental goals. The proceeding is pending. Any actions taken by the NYSPSC could affect market design and market prices in New York.

Independent Power Producers of New York (IPPNY) Complaint — On February 20, 2020, FERC rejected a rehearing request asking FERC to direct NYISO to require that capacity from existing generation resources that would have exited the market but for out-of-market payments be mitigated and found that NYISO complied with the initial order to establish a stakeholder process to consider whether buyer side mitigation measures are needed to address these agreements. On January 9, 2017, EPSA requested FERC to promptly direct NYISO to file tariff provisions to address pending market concerns related to out-of-market payments to existing generation in NYISO. On April 5, 2018, EPSA filed a motion for renewed request for expedited action on the MOPR. Failure to implement buyer-side mitigation measures could result in uneconomic entry, which artificially decreases capacity prices below competitive market levels.

New York Buyer Side Mitigation Proceedings — On February 20, 2020, FERC issued multiple orders pertaining to the NYISO capacity market. The orders narrowed certain exemptions to buyer side mitigation measures. Specifically, FERC stated that certain renewable and self-supply resources would be exempt from offer floor mitigation but rejected NYISO’s proposal of a 1,000 MW cap on renewable resources that could qualify for the exemption. FERC ordered NYISO to make a compliance filing narrowly tailoring its cap. FERC also rejected a complaint to exempt new electric storage resources. It also rejected a blanket exemption to demand response providers currently subject to mitigation but granted a request for new demand response to receive a blanket exemption from the buyer side mitigation measures. Implementation of buyer-side mitigation measures to address price suppression provides more accurate capacity price signals in the competitive market.

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 became effective on March 1, 2019 and the second phase will become effective on March 1, 2020. To date, the ORDC reforms have produced a noticeable improvement in scarcity pricing.

Environmental Regulatory Matters

NRG is subject to numerous environmental laws in the development, construction, ownership and operation of power plants. 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 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 ash storage and 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.

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.

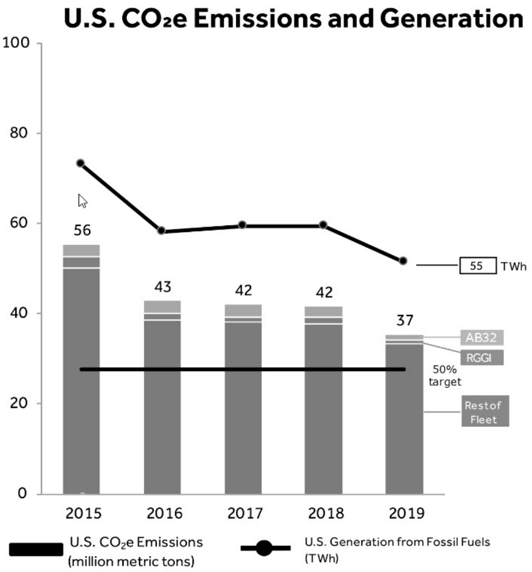
Clean Power Plan — The attention in recent years on GHG emissions has resulted in federal regulations and state legislative and regulatory action. In October 2015, the EPA finalized the CPP, addressing GHG emissions from existing EGUs. On February 9, 2016, the U.S. Supreme Court stayed the CPP. In July 2019, EPA promulgated the ACE rule, which rescinded the CPP, which sought to broadly regulate CO2 emissions from the power sector. The ACE rule requires states that have coal-fired EGUs to develop plans to seek heat rate improvements from coal-fired EGUs. Texas, Illiniois and Delaware have started working on plans to comply with the ACE rule. Numerous parties have challenged the ACE rule in the D.C. Circuit and numerous parties have filed petitions for reconsideration with the EPA.

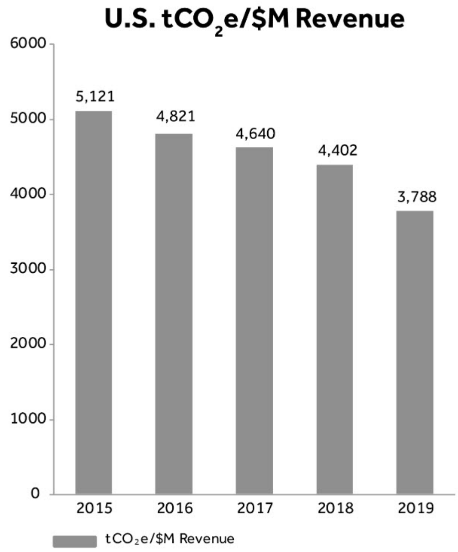
Greenhouse Gas Emissions — NRG emits CO_2 (and small quantities of other GHGs) when generating electricity at a majority of its facilities. The graphs presented below illustrate NRG's domestic emissions of CO_{2e} for the 2015 through 2019 period. Nearly all (>99%) of NRG's GHG emissions are subject to federal (U.S. EPA) GHG reporting requirements. From 2015 to 2019, the Company's CO_{2e} emissions decreased from 56 million metric tons to 37 million metric tons, representing a 34% reduction. The factors leading to the decreased emissions include reductions in fleet-wide annual net generation and a market-driven shift from coal as a primary fuel to natural gas.

On September 24, 2019, NRG announced the acceleration of its science-based GHG emissions reduction goals to align with prevailing climate science, limiting warming to a 1.5 degree Celsius scenario. Under its new GHG emissions reduction timeline, NRG is targeting to achieve a 50% reduction by 2025 and net-zero emissions by 2050, from a 2014 baseline.

As of December 31, 2019, less than 25% of the Company's consolidated operating revenues were derived from coal-fired operating assets.

The following tables reflect the Company’s generation portfolio, including leased facilities and those accounted for through equity method investments. Prior year information was adjusted to remove divested assets.





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. On August 14, 2019, the EPA proposed targeted changes to the April 2015 Rule including changes to address the August 2018 D.C. Circuit decision. On December 2, 2019, the EPA released for comment "Closure Part A Proposal" to revise the CCR Rule to address the D.C. Circuit's 2018 decision regarding the adequacy of clay-lined impoundments, obligations to close all unlined impoundments and related deadlines. On February 20, 2020, the EPA proposed the framework for developing and implementing a federal permit program for states that are not approved to administer the CCR rule. We anticipate that the EPA will promulgate new regulations to address these issues and others as it reconsiders other aspects of the existing rule. The Company will provide estimates of the cost of compliance after the EPA finalizes revisions to the rule.

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, *Commitments and Contingencies*, 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 has been extended twice through addendums to cover payments through December 31, 2019. STPNOC expects the settlement to be extended for another three-year period. 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 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 in 1985, 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. Texas is currently in a compact with the state of Vermont, and the compact low-level waste facility located in Andrews County in Texas has been operational since 2012.

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.

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 FGD, fly ash, bottom ash, and flue gas mercury control. On September 18, 2017, the EPA promulgated a final rule that, among other things, 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. On April 12, 2019, the United States Court of Appeals for the Fifth circuit addressed challenges to the rule brought by several environmental groups related to legacy wastewaters and coal ash leachate and remanded portions of the rule to the EPA. On November 22, 2019, the EPA proposed amending the 2015 ELG rule by: (x) decreasing the stringency of the selenium limit (but increasing the stringency of the nitrate and mercury limits) for FGD wastewater; (y) relaxing the zero-discharge requirement for bottom ash transport water; and (z) changing several deadlines. 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 EPA finalizes revisions to the rule.

Regional Environmental Developments

NY NOx — On December 31, 2019, the New York State Department of Environmental Conservation finalized a more stringent NOx regulation that will result in the retirement of the Company's combustion turbines in Astoria, New York in 2023.

Ash Regulation in Illinois — On July 30, 2019, Illinois enacted legislation that requires the state to promulgate regulations regarding coal ash at surface impoundments. We expect the state to promulgate the implementing regulations in March 2021, at which time regulated entities will then prepare and submit permit applications.

Customers

NRG sells to a wide variety of customers, primarily end-use customers in the residential, commercial and industrial sectors. The Company owns and operates power plants to generate and sell power to wholesale customers, such as utilities and other intermediaries. The Company had no customer that comprised more than 10% of the Company's consolidated revenues for the year ended December 31, 2019.

Employees

As of December 31, 2019, NRG and its consolidated subsidiaries had 4,577 employees, approximately 24% of whom were covered by U.S. bargaining agreements. During 2019, 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 SEC's website, *www.sec.gov*, and 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 2 — Properties

Listed below are descriptions of NRG's interests in facilities, operations and/or projects owned or leased as of December 31, 2019. The rated MW capacity figures provided represent nominal summer MW capacity of power generated. Net MW capacity is adjusted for the Company's owned or leased interest, excluding capacity from inactive/mothballed units as of December 31, 2019. 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[(a)]	Net MW Capacity[(b)]	% 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	385	385	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	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	**11,765**	**10,061**	
East							
Arthur Kill	NYISO	Fossil	Natural Gas	NY	866	866	100.0
Astoria Turbines	NYISO	Fossil	Natural Gas	NY	423	423	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
Devon	ISO-NE	Fossil	Oil	CT	133	133	100.0
Fisk	PJM	Fossil	Oil	IL	171	171	100.0
Indian River	PJM	Fossil	Coal	DE	410	410	100.0
Indian River	PJM	Fossil	Oil	DE	16	16	100.0
Joliet	PJM	Fossil	Natural Gas	IL	1,317	1,317	—[(c)]
Middletown	ISO-NE	Fossil	Oil	CT	762	762	100.0
Montville	ISO-NE	Fossil	Oil	CT	491	491	100.0
Oswego	NYISO	Fossil	Oil	NY	1,617	1,617	100.0
Powerton	PJM	Fossil	Coal	IL	1,538	1,538	—[(c)]
Vienna	PJM	Fossil	Oil	MD	167	167	100.0
Waukegan	PJM	Fossil	Coal	IL	682	682	100.0
Waukegan	PJM	Fossil	Oil	IL	101	101	100.0
Will County	PJM	Fossil	Coal	IL	510	510	100.0
				Total East	**9,426**	**9,426**	
West/Other							
Agua Caliente	WECC	Renewable	Solar	AZ	290	102	35.0
Cottonwood	MISO	Fossil	Natural Gas	TX	1,153	1,153	—[(c)]
Gladstone		Fossil	Coal	AUS	1,613	605	37.5
Ivanpah	CAISO	Renewable	Solar	CA	393	214	54.5
Long Beach	CAISO	Fossil	Natural Gas	CA	252	252	100.0
Midway-Sunset	CAISO	Fossil	Natural Gas	CA	226	113	50.0
Residential solar		Renewable	Solar	various	60	60	100.0
Stadiums		Renewable	Solar	various	5	5	100.0
Sunrise	CAISO	Fossil	Natural Gas	CA	586	586	100.0
Watson	CAISO	Fossil	Natural Gas	CA	416	204	49.0
				Total West/Other	**4,994**	**3,294**	
				Total Fleet	**26,185**	**22,781**	

(a) MW capacity of the facility without taking into account NRG ownership percentage

(b) 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

(c) NRG leases 100% interests in the Cottonwood facility, Units 7 and 8 of the Joliet facility, and the Powerton facility, through facility lease agreements expiring in 2025, 2030 and 2034 respectively. NRG owns 100% interest in Joliet Unit 6. NRG operates the Cottonwood, Joliet and Powerton facilities.

Other Properties

NRG owns several real properties and facilities related to its generation assets, other vacant real property unrelated to its generation assets, 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 at 910 Louisiana Street, Houston, Texas, as well as its retail business offices and call centers, and various other office space.

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 during the years shown below, as described in Item 15 — Note 4, *Acquisitions, Discontinued Operations and Dispositions*, to the Consolidated Financial Statements.

	Year Ended December 31,				
(In millions except ratios and per share data)	**2019**	**2018**	**2017**	**2016**	**2015**
Statement of income data:					
Total operating revenues	$ 9,821	$ 9,478	$ 9,074	$ 8,915	$ 10,842
Total operating costs and other expenses [(a)]	(8,922)	(8,897)	(8,850)	(9,095)	(10,796)
Impairment losses [(b)]	(5)	(99)	(1,534)	(483)	(4,823)
Operating income/(loss)	1,290	982	(741)	33	(4,347)
Impairment losses on investments	(108)	(15)	(79)	(268)	(40)
Income/(loss) from continuing operations, net	4,120	460	(1,345)	(956)	(6,379)
Income/(loss) from discontinued operations, net	321	(192)	(992)	65	(57)
Net income/(loss) attributable to NRG Energy, Inc.	$ 4,438	$ 268	$ (2,153)	$ (774)	$ (6,382)
Common share data:					
Basic shares outstanding — average	262	304	317	316	329
Diluted shares outstanding — average	264	308	317	316	329
Shares outstanding — end of year	249	284	317	315	314
Per share data:					
Net income/(loss) attributable to NRG — basic	$ 16.94	$ 0.88	$ (6.79)	$ (2.22)	$ (19.46)
Net income/(loss) attributable to NRG — diluted	16.81	0.87	(6.79)	(2.22)	(19.46)
Dividends declared per common share	0.12	0.12	0.12	0.24	0.58
Book value [(c)]	$ 6.66	$ (4.35)	$ 6.20	$ 14.09	$ 17.29
Business metrics:					
Cash flow from operations	$ 1,413	$ 1,377	$ 1,610	$ 1,908	$ 1,419
Liquidity position [(d)]	2,147	1,977	2,760	1,768	2,102
Return on equity [(e)]	267.67 %	(21.72)%	(109.40)%	(17.41)%	(117.45)%
Ratio of debt to total capitalization [(f)]	76.99 %	126.12 %	81.40 %	68.26 %	63.96 %
Balance sheet data:					
Current assets	$ 3,088	$ 3,600	$ 4,437	$ 6,747	$ 8,231
Current liabilities	2,359	2,398	3,354	4,736	5,215
Property, plant and equipment, net	2,593	3,048	5,974	7,877	8,283
Total assets	12,531	10,628	23,355	30,716	33,738
Long-term debt, including current maturities, and finance leases	5,891	6,521	9,384	10,071	10,867
Total stockholders' equity	$ 1,658	$ (1,234)	$ 1,968	$ 4,446	$ 5,434

(a) Excludes impairment losses and impairment losses on investments

(b) Includes goodwill impairments recorded as described in Item 15 — Note 12, *Goodwill and Other Intangibles*, to the Consolidated Financial Statements

(c) Total stockholders' equity, divided by shares outstanding as of the end of the year

(d) 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 $32 million, $33 million, $37 million, $2 million and $91 million as of December 31, 2019, 2018 , 2017, 2016 and 2015 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

(e) Net income attributable to NRG Energy Inc., divided by total stockholders' equity

(f) Total debt and capital leases minus cash and cash equivalents, divided by total capitalization (total debt and capital leases plus total stockholders' equity and non-controlling interest) minus cash and cash equivalents

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 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 that are most important to both the portrayal of the Company's financial condition and results of operations, and require management's most difficult, subjective or complex judgments.

As you read this discussion and analysis, refer to Item 15 — *Consolidated Statements of Operations*, which presents the results of the Company's operations for the years ended December 31, 2019, 2018 and 2017, and also refer to Item 1 — *Business* for more detailed discussion about the Company's business.

As further described in Item 15 — Note 4, *Acquisitions, Discontinued Operations and Dispositions*, to the Consolidated Financial Statements, the Company determined in prior years that the following businesses were discontinued operations and recast to present their results in the corporate segment:

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

Executive Summary

NRG is an integrated power company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to customers by producing and selling electricity and related products and services in major competitive power markets in the U.S. and Canada 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 brand names NRG, Reliant, Green Mountain Energy, Stream and XOOM Energy, as well as other brand names owned by NRG, supported by approximately 23,000 MW of generation as of December 31, 2019.

Business Environment

The industry dynamics and external influences affecting the Company and its businesses, and the power generation and retail energy industry in 2019 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 customers and producers. In 2019, the average natural gas prices at Henry Hub was 15.0% lower than in 2018.

If long-term gas prices increase, the Company is likely to encounter higher realized energy prices, leading to higher energy revenues as lower priced hedge contracts mature and are replaced by contracts with higher gas and power prices. This impact is partially offset by the retail business, as NRG's retail gross margins have historically decreased as natural gas prices increase.

NRG's retail gross margins have historically improved as natural gas prices decline. This would be partially offset by 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. 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 6, *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.

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, 2019, 2018 and 2017. ERCOT power prices increased primarily due to the continued effect of lower reserve margins as a result of asset retirements in the region. Power prices in the East and West/Other decreased for the year ended December 31, 2019 as compared to the same period in 2018 due to mild weather and lower gas prices, along with lower summer prices in California. For the year ended December 31, 2018 as compared to the same period in 2017, power prices in the East and West/Other increased, 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			2019 vs 2018	2018 vs 2017
Region	**2019**	**2018**	**2017**	**Change %**	**Change %**
Texas [a]					
ERCOT - Houston[a]	$ 51.44	$ 37.29	$ 33.95	38 %	10 %
ERCOT - North[a]	50.80	36.26	25.86	40 %	40 %
East					
NY J/NYC[b]	33.73	47.19	38.34	(29)%	23 %
NEPOOL[b]	34.89	49.96	37.18	(30)%	34 %
COMED (PJM)[b]	28.28	34.60	32.46	(18)%	7 %
PJM West Hub[b]	30.85	41.66	34.14	(26)%	22 %
West/Other					
CAISO - SP15[b]	38.15	47.33	36.48	(19)%	30 %
MISO - Louisiana Hub[b]	30.58	43.70	40.02	(30)%	9 %

(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, including the impact of settled hedges, for the years ended December 31, 2019, 2018 and 2017:

	Average Realized Power Price ($/MWh)				
	Year Ended December 31			2019 vs 2018	2018 vs 2017
Region	**2019**	**2018**	**2017**	**Change %**	**Change %**
Texas	$ 46.58	$ 37.12	$ 33.45	25 %	11 %
East	28.97	40.58	36.21	(29)%	12 %
West/Other	32.41	36.38	44.82	(11)%	(19)%

The average realized power prices for the year ended December 31, 2019, as compared to the prior year, increased in Texas as a result of higher power prices and decreased in East and West/Other as a result of the roll off of hedges. The average realized power prices for the year ended December 31, 2018, as compared to the prior year, increased in Texas and East as a result of higher power prices and decreased in West/Other 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, continue 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 2019 energy consumption in the ERCOT market was generated from carbon-free resources with wind power contributing 20%. In addition, subsidies and incentives have contributed to the increase in renewable power sources, and customer awareness and preferences have shifted toward sustainable solutions. Increased demand for sustainable energy products from both residential and commercial customers 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, customers 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's operations are typically not exposed to the effects of extreme weather in all parts of its business at once. A significant portion of the Company's business is located within Texas, and extreme weather conditions occurring in Texas may have a material impact on the Company's financial position.

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 25, *Environmental Matters*, to the Consolidated Financial Statements and Item 1— Business, *Environmental Matters*. Details of regulatory matters are presented in Item 15 — Note 24, *Regulatory Matters*, to the Consolidated Financial Statements and Item 1— Business, *Regulatory Matters*. Details of legal proceedings are presented in Item 15 — Note 23, *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 has substantially completed its three-year Transformation Plan and expects to fully complete the remaining margin enhancement activities by the end of 2020. The Transformation Plan's targets and the Company's achievements towards such targets are as follows:

Operations and Cost Excellence

The Company targeted 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 2018 and $590 million of cost savings and $135 million of margin enhancements during 2019.

Under the Transformation Plan, by December 31, 2019, the Company fully realized $370 million of non-recurring working capital improvements and $278 million of one-time costs to achieve.

Portfolio Optimization

The Company targeted and completed $3.0 billion of asset sale cash proceeds received through December 31, 2019 as described below:

- In 2017 and 2018, NRG executed asset sales for aggregate cash of $1.6 billion, which includes the sale of its interest in NRG Yield, Inc and its Renewables Platform, BETM, Buckthorn Solar, and various other assets.
- On February 4, 2019, NRG sold the South Central portfolio, a 3,555 MW portfolio of generation assets, for cash consideration of $1.0 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 $385 million, excluding working capital and other adjustments

Capital Structure and Allocation

As of December 31, 2018, the Company achieved the planned credit ratio of 3.0x net debt / adjusted EBITDA[a]. During the first quarter of 2019, the Company revised its credit metrics target in order to further strengthen its balance sheet and improve credit ratings by reducing leverage.

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

Other Significant Events

The following additional significant events occurred during 2019:

Stream Energy Acquisition

- On August 1, 2019, the Company completed the acquisition of Stream Energy's retail electricity and natural gas business operating in 9 states and Washington, D.C. for $329 million, including working capital and other adjustments of approximately $29 million. The acquisition increased NRG's retail portfolio by approximately 600,000 RCEs or 450,000 customers.

Financing Activities

- On May 14, 2019, NRG issued $733 million of aggregate principal amount at par of 5.25% senior unsecured notes due 2029. The proceeds from the issuance of the 2029 Senior Notes were utilized to redeem the remaining Company's $733 million of 6.25% Senior Notes due 2024.
- On May 28, 2019, NRG amended its existing credit agreement to, among other things, provide for a $184 million increase in revolving commitments, resulting in aggregate revolving commitments under the amended credit agreement equal to $2.6 billion. See Note 13, *Debt and Finance Leases*, for further discussion.
- On May 28, 2019, NRG issued $1.1 billion of aggregate principal amount of senior secured first lien notes, consisting of $600 million 3.75% senior secured first lien notes due 2024 and $500 million 4.45% senior secured first lien notes due 2029, or the Senior Secured Notes, at a discount. The proceeds from the issuance of the Senior Secured Notes, as well as cash on hand, were used to repay the Company's $1.7 billion 2023 Term Loan facility, resulting in a decrease of $594 million to long-term debt outstanding.

Share Repurchases

- In 2018, the Company's board of directors authorized the Company to repurchase $1.5 billion of its common stock. $1.25 billion was executed in 2018 with the remaining $0.25 billion completed in the first quarter of 2019.
- In 2019, the Company's board of directors authorized the Company to repurchase an additional $1.25 billion of its common stock, which was completed as of February 27, 2020.

Renewable Power Purchase Agreements

- During 2019, NRG began execution of its strategy to procure mid to long-term generation through power purchase agreements. As of December 31, 2019, NRG has entered into PPAs totaling approximately 1,600 MWs with third-party project developers and other counterparties. The tenor of these agreements is an average of ten years. The Company expects to continue evaluating and executing similar agreements that support the needs of the business.

Dividend Increase

- Beginning in the first quarter of 2020, NRG increased the annual dividend to $1.20 per share from $0.12 per share and expects to target an annual dividend growth rate of 7-9% per share in subsequent years.

Valuation Allowance for Net Deferred Tax Assets

- During the year ended December 31, 2019, NRG released the majority of its valuation allowance against its U.S. federal and state deferred tax assets, resulting in a non-cash benefit to income tax expense of approximately $3.5 billion. Refer to Item 15 – Note 20, *Income Taxes*, to the Consolidated Financial Statements for further discussion of the release in valuation allowance.

Consolidated Results of Operations for the years ended December 31, 2019 and 2018

The following table provides selected financial information for the Company:

(In millions, except otherwise noted)	Year Ended December 31, 2019	Year Ended December 31, 2018	Change
Operating Revenues			
Retail revenue	$ 7,533	$ 6,894	$ 639
Energy revenue[(a)]	1,169	1,496	(327)
Capacity revenue[(a)]	700	825	(125)
Mark-to-market for economic hedging activities	33	(130)	163
Other revenues[(a)(b)]	386	393	(7)
Total operating revenues	9,821	9,478	343
Operating Costs and Expenses			
Cost of sales[(c)]	5,878	5,878	—
Mark-to-market for economic hedging activities	53	(144)	(197)
Contract and emissions credit amortization[(c)]	19	27	8
Operations and maintenance	1,082	1,083	1
Other cost of operations	271	264	(7)
Total cost of operations	7,303	7,108	(195)
Depreciation and amortization	373	421	48
Impairment losses	5	99	94
Selling, general and administrative	827	799	(28)
Reorganization costs	23	90	67
Development costs	7	11	4
Total operating costs and expenses	8,538	8,528	(10)
Gain on sale of assets	7	32	(25)
Operating Income	1,290	982	308
Other Income/(Expense)			
Equity in earnings of unconsolidated affiliates	2	9	(7)
Impairment losses on investments	(108)	(15)	(93)
Other income, net	66	18	48
Net loss on debt extinguishment	(51)	(44)	(7)
Interest expense	(413)	(483)	70
Total other expenses	(504)	(515)	11
Income from Continuing Operations Before Income Taxes	786	467	319
Income tax (benefit)/expense	(3,334)	7	(3,341)
Income from Continuing Operations	4,120	460	3,660
Income/(loss) from discontinued operations, net of income tax	321	(192)	513
Net Income	4,441	268	4,173
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	3	—	3
Net Income Attributable to NRG Energy, Inc.	$ 4,438	$ 268	$ 4,170
Business Metrics			
Average natural gas price — Henry Hub ($/MMBtu)	$ 2.63	$ 3.09	(15)%

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

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 for the years ended December 31, 2019 and 2018 based on the Company's current view of reportable segments:

	Year Ended December 31, 2019				
($ in millions, except otherwise noted)	**Texas**	**East**	**West/Other**	**Corporate/Eliminations**	**Total**
Retail revenue	$ 6,232	$ 1,304	$ —	$ (3)	$ 7,533
Energy revenue[(a)]	529	322	318	—	1,169
Capacity revenue	—	664	36	—	700
Mark-to-market for economic hedging activities	47	(29)	16	(1)	33
Other revenue	261	58	70	(3)	386
Operating revenue	7,069	2,319	440	(7)	9,821
Cost of fuel	(694)	(208)	(178)	—	(1,080)
Purchased power[(b)]	(1,557)	(612)	(13)	1	(2,181)
Other costs of sales[(b)(c)(d)]	(2,233)	(342)	(42)	—	(2,617)
Mark-to-market for economic hedging activities	(57)	4	(1)	1	(53)
Contract and emission credit amortization	(19)	—	—	—	(19)
Gross margin	$ 2,509	$ 1,161	$ 206	$ (5)	$ 3,871
Less: Mark-to-market for economic hedging activities, net	(10)	(25)	15	—	(20)
Less: Contract and emission credit amortization	(19)	—	—	—	(19)
Economic gross margin	$ 2,538	$ 1,186	$ 191	$ (5)	$ 3,910

[(a)] Intercompany sales of $1,439 million and $59 million were eliminated within the Texas and East segments, respectively

[(b)] Includes $104 million total in purchased power in the East that is not related to retail activities

[(c)] Includes capacity and emissions credits

[(d)] Includes $1,944 million and $9 million of electric TDSP charges for Texas and East, respectively

Business Metrics	**Texas**	**East**	**West/Other**	**Total**
Mass Market electricity sales volume (GWh)	38,958	9,918		48,876
C&I electricity sales volume (GWh)	18,976	1,214		20,190
Natural gas retail sales volumes (MDth)		23,359		23,359
Average retail Mass Market customer count (in thousands)	2,358	1,112		3,470
Ending retail Mass Market customer count (in thousands)	2,450	1,228		3,678
GWh sold[(a)]	42,662	11,113	9,811	63,586
GWh generated[(b)]	37,995	6,913	9,462	54,370

[(a)] Includes 33,191 GWh of intercompany sales within Texas

[(b)] Includes owned generation and excludes equity investments

($ in millions, except otherwise noted)	Year Ended December 31, 2018				
	Texas	East	West/Other[a]	Corporate/Eliminations	Total
Retail revenue	$ 5,856	$ 1,039	$ —	$ (1)	$ 6,894
Energy revenue[b]	371	546	566	13	1,496
Capacity revenue	—	746	79	—	825
Mark-to-market for economic hedging activities	(77)	(35)	(5)	(13)	(130)
Other revenue	251	75	84	(17)	393
Operating revenue	6,401	2,371	724	(18)	9,478
Cost of fuel	(734)	(308)	(250)	(6)	(1,298)
Purchased power[c]	(1,397)	(621)	(1)	(7)	(2,026)
Other costs of sales[c][d][e]	(2,180)	(335)	(37)	(2)	(2,554)
Mark-to-market for economic hedging activities	169	(37)	(1)	13	144
Contract and emission credit amortization	(26)	—	(1)	—	(27)
Gross margin	$ 2,233	$ 1,070	$ 434	$ (20)	$ 3,717
Less: Mark-to-market for economic hedging activities, net	92	(72)	(6)	—	14
Less: Contract and emission credit amortization	(26)	—	(1)	—	(27)
Economic gross margin	$ 2,167	$ 1,142	$ 441	$ (20)	$ 3,730

[a] Includes BETM, Agua Caliente and Ivanpah, which were sold or deconsolidated as of July, August and April 2018, respectively
[b] Intercompany sales of $1,173 million and $(32) million were eliminated within the Texas and East segments, respectively
[c] Includes $216 million total in purchased power and other cost of sales in the East that is not related to retail activities
[d] Includes capacity and emissions credits
[e] Includes $1,961 million and $4 million of electric TDSP charges for Texas and East, respectively

Business Metrics	Texas	East	West/Other	Total
Mass Market electricity sales volume (GWh)	37,846	7,968		45,814
C&I electricity sales volume (GWh)	20,192	984		21,176
Natural gas retail sales volumes (MDth)		11,253		11,253
Average retail Mass Market customer count (in thousands)	2,209	854		3,063
Ending retail Mass Market customer count (in thousands)	2,318	1,002		3,320
GWh sold[a]	42,701	14,020	10,968	67,689
GWh generated[b]	38,214	10,119	10,970	59,303

[e] Includes 31,198 GWh of intercompany sales within Texas
[b] Includes owned generation and excludes equity investments

The table below represents the weather metrics for 2019 and 2018:

Weather Metrics	Years ended December 31,			Quarters ended December 31,			Quarters ended September 30,			Quarters ended June 30,			Quarters ended March 31,		
	Texas	East	West/Other[a]	Texas	East	West/Other[a]	Texas	East	West/Other[a]	Texas	East	West/Other[a]	Texas	East	West/Other[a]
2019															
CDDs[b]	3,115	1,349	1,899	266	98	136	1,840	869	1,219	934	348	513	75	34	31
HDDs[b]	1,868	4,615	2,199	757	1,664	806	—	29	9	70	465	192	1,041	2,457	1,192
2018															
CDDs	3,130	1,430	1,975	228	111	126	1,657	919	1,189	1,101	364	599	144	36	61
HDDs	1,875	2,349	2,090	815	1,719	808	1	37	9	91	561	207	968	32	1,066
10 year average															
CDDs	3,053	1,261	1,882	266	80	147	1,672	794	1,135	1,009	354	554	106	33	46
HDDs	1,742	4,632	2,104	705	1,622	792	6	58	13	60	508	210	971	2,444	1,089

[a] The West/Other weather metrics are comprised of the average of the CDD and HDD regional results for the West - California and West - South Central regions

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

Gross margin and economic gross margin

Gross margin increased $154 million and economic gross margin increased $180 million for the year ended December 31, 2019, compared to the same period in 2018. The detail by segment is as follows:

Texas

		(In millions)
Higher gross margin due to a 25% increase in average realized prices due to heat rate expansion on generation sold[a]	$	285
Higher gross margin due to a 6% increase in generation volumes driven by a planned outage at STP and a forced outage at T.H. Wharton in 2018, partially offset by current year forced outages at coal facilities		44
Higher gross margin due to Gregory return to service in June 2019		38
Higher gross margin driven by higher retail sales volumes from the XOOM and Stream acquisitions		29
Higher gross margin from market optimization activities		28
Higher gross margin due to margin enhancement initiatives from reduced fuel supply cost		13
Lower gross margin due to lower sales of NOx emission credits		(23)
Lower gross margin on retail sales from weather due to the unfavorable impact of purchasing incremental supply during extreme weather conditions at escalated prices above $1,000/MWh mainly in the summer of 2019		(21)
Lower gross margin on retail sales from weather due to the unfavorable impact selling back excess supply in 2019 as compared to 2018		(11)
Lower gross margin on retail sales due to higher supply costs driven by an increase in power prices of approximately $5.80 per MWh, or $252 million[a], partially offset by higher revenue primarily driven by our margin enhancement initiatives of approximately $5.70 per MWh, or $249 million		(3)
Other		(8)
Increase in economic gross margin	$	371
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		(102)
Increase in contract and emission credit amortization		7
Increase in gross margin	$	276

[a] Includes effects of intercompany sales and purchases that were eliminated within the segment

East

	(In millions)
Higher gross margin driven by higher retail sales volumes from the XOOM and Stream acquisitions	$ 87
Higher gross margin mainly due to a 9% increase in weighted average realized prices on generation sold, primarily at Midwest Generation[(a)]	35
Higher gross margin from retail sales due to lower supply costs coupled with an increase in load contract volumes	15
Higher gross margin due to a 10% increase in PJM generation capacity prices, partially offset by an 8% decrease in New England generation capacity prices	14
Higher gross margin on retail sales due to lower supply costs driven by a decrease in power prices of approximately $1.50 per MWh, or $15 million[(a)], partially offset by lower revenue of approximately $0.50 per MWh, or $6 million	9
Higher gross margin due to business interruption proceeds in 2019	8
Lower gross margin on generation sold due to a 26% decrease in economic generation volumes due to dark spread and spark spread contractions and outages in 2019	(45)
Lower gross margin from demand response activities due to lower auction clearing prices and fewer MW sold in PJM in 2019 as compared to 2018	(29)
Lower gross margin driven by a decrease in New York realized generation capacity revenues	(29)
Lower gross margin from market optimization activities	(17)
Lower gross margin due to the sale of Keystone and Conemaugh in the third quarter of 2018	(9)
Other	5
Increase in economic gross margin	$ 44
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	47
Increase in gross margin	$ 91

[(a)] Includes effects of intercompany sales and purchases that were eliminated within the segment

West/Other

	(In millions)
Lower gross margin due to the deconsolidations of Ivanpah and Agua in April 2018 and August 2018, respectively	$ (118)
Lower gross margin due to the retirement of Encina in December 2018 and the sales of BETM and Guam in the third quarter of 2018 and first quarter of 2019, respectively	(113)
Lower gross margin due to insurance proceeds from outages in 2018	(14)
Lower gross margin due primarily to the Sunrise forced outage in 2019	(11)
Higher gross margin mainly due to a 24% increase in weighted average realized prices on generation sold in the West, partially offset by a 17% decrease in weighted average realized prices on generation sold at Cottonwood	4
Other	2
Decrease in economic gross margin	$ (250)
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	21
Increase in contract and emission credit amortization	1
Decrease in gross margin	$ (228)

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 $34 million during the year ended December 31, 2019, compared to the same period in 2018.

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

	Year Ended December 31, 2019				
(In millions)	**Texas**	**East**	**West/Other**	**Eliminations**	**Total**
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	$ 21	$ 14	$ 12	$ —	$ 47
Net unrealized gains/(losses) on open positions related to economic hedges	26	(43)	4	(1)	(14)
Total mark-to-market gains/(losses) in operating revenues	$ 47	$ (29)	$ 16	$ (1)	$ 33
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (117)	$ 3	$ (1)	$ —	$ (115)
Reversal of acquired loss positions related to economic hedges	1	5	—	—	6
Net unrealized gains/(losses) on open positions related to economic hedges	59	(4)	—	1	56
Total mark-to-market (losses)/gains in operating costs and expenses	$ (57)	$ 4	$ (1)	$ 1	$ (53)

	Year Ended December 31, 2018				
(In millions)	**Texas**	**East**	**West/Other**	**Eliminations**	**Total**
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (56)	$ (26)	$ 7	$ (2)	$ (77)
Net unrealized losses on open positions related to economic hedges	(21)	(9)	(12)	(11)	(53)
Total mark-to-market losses in operating revenues	$ (77)	$ (35)	$ (5)	$ (13)	$ (130)
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 15	$ (11)	$ (2)	$ 2	$ 4
Reversal of acquired gain positions related to economic hedges.	(11)	1	—	—	(10)
Net unrealized gains/(losses) on open positions related to economic hedges	165	(27)	1	11	150
Total mark-to-market gains/(losses) in operating costs and expenses	$ 169	$ (37)	$ (1)	$ 13	$ 144

Mark-to-market results consist of unrealized gains and losses on contracts 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.

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, 2019 the $33 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. The $53 million loss in operating costs and expenses from economic hedge positions was driven primarily by the reversal of previously recognized unrealized gains, partially offset by an increase in the value of open positions as a result of gains on ERCOT heat rate positions due to heat rate expansion.

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, 2019 and 2018. 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)	**2019**	**2018**
Trading gains		
Realized	$ 57	$ 77
Unrealized	20	17
Total trading gains	$ 77	$ 94

Operations and Maintenance Expenses

Operations and maintenance expenses are comprised of the following:

(In millions)	**Texas**	**East**	**West/Other**	**Corporate**	**Eliminations**	**Total**
Year Ended December 31, 2019	$ 605	$ 368	$ 105	$ 9	$ (5)	$ 1,082
Year Ended December 31, 2018	593	402	93	3	(8)	1,083

Operations and maintenance expenses decreased by $1 million for the year ended December 31, 2019, compared to the same period in 2018, due to the following:

	(In millions)
Increase primarily related to the lease of the Cottonwood facility from February 4, 2019	$ 37
Increase in investments in Texas plants in preparation for summer operations	21
Increase due to XOOM and Stream Energy acquisitions in June 2018 and August 2019, respectively	21
Increase in operations and maintenance expenses due to margin enhancement initiatives	8
Increase in outages primarily due to both planned and forced outages in 2019, partially offset by planned STP outages in 2018	3
Decrease due to the final settlement of the asbestos liability and resulting reduction of the accrual for Midwest Generation	(27)
Decrease due to the deconsolidations of Ivanpah and Agua Caliente in 2018	(20)
Decrease in variable chemical costs due to reduction in East generation volumes	(18)
Decrease due to retirement of Encina and the sale of Keystone and Conemaugh in 2018	(14)
Decrease due to payments in settlement of certain legal matters in 2018	(13)
Other	1
Increase in operations and maintenance expense	$ (1)

Other Cost of Operations

Other Cost of operations are comprised of the following:

(In millions)	Texas	East	West/Other	Total
Year Ended December 31, 2019	$ 166	$ 78	$ 27	$ 271
Year Ended December 31, 2018	162	77	25	264

Other cost of operations increased by $7 million for the year ended December 31, 2019, compared to the same period in 2018, due to the following:

	(In millions)
Increase in ARO accretion expense due to Encina decommissioning and Jewett Mine accretion in 2019, partially offset by a decrease due to prior year write-off of S.R. Bertron	$ 15
Increase in gross receipts tax due to the Stream Energy acquisition and higher revenue from increased rates and customer counts	10
Decrease due to deconsolidation of Ivanpah and Agua Caliente in 2018	(8)
Decrease due to resolution of favorable property tax disputes	(7)
Decrease in other cost of operations due to cost efficiencies as a result of the Transformation Plan	(5)
Other	2
Increase in other cost of operations	$ 7

Depreciation and Amortization

Depreciation and amortization expenses are comprised of the following:

(In millions)	Texas	East	West/Other	Corporate	Total
Year Ended December 31, 2019	$ 188	121	$ 33	$ 31	$ 373
Year Ended December 31, 2018	156	105	127	33	421

Depreciation and amortization expense decreased by $48 million for the year ended December 31, 2019, compared to the same period in 2018, due to the deconsolidations of Ivanpah and Agua Caliente in April and August 2018, respectively, and the sale of the Cottonwood facility in February 2019, partially offset by the acquisitions of Stream Energy and XOOM.

Impairment Losses

For the year ended December 31, 2019 the Company recorded an impairment loss of $5 million compared to impairment losses of $99 million for the same period in 2018, as further described in Item 15 — Note 11, *Asset Impairments*, to the Consolidated Financial Statements.

Selling, General and Administrative Expenses

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

(In millions)	Texas	East	West/Other	Corporate	Total
Year Ended December 31, 2019	$ 481	$ 291	$ 31	$ 24	$ 827
Year Ended December 31, 2018	456	241	56	46	799

Selling, general and administrative expenses increased by $28 million for the year ended December 31, 2019, compared to the same period in 2018, due to the following:

	(In millions)
Increase in selling and marketing expenses for margin enhancement initiatives	$ 56
Increase in selling expense due to the acquisitions of XOOM and Stream Energy in June 2018 and August 2019, respectively	31
Increase in bad debt expense primarily due to higher customer attrition and increased revenue due to acquisitions	10
Decrease in general and administrative expense from cost efficiencies as a result of the Transformation Plan	(51)
Decrease due to the sale of BETM in 2018	(19)
Other	1
Increase in selling, general and administrative expenses	$ 28

Reorganization Costs

Reorganization costs, primarily related to severance and contract modifications, decreased by $67 million for the year ended December 31, 2019, compared to the same period in 2018. The Company has substantially completed its three-year Transformation Plan and expects this expense to decrease further as we complete the implementation by the end of 2020.

Gain on Sale of Assets

Gain on sale of assets for the year ended December 31, 2019 represents a gain on the sale of an investment, while the gain for the year ended December 31, 2018 represents gains on the sales of BETM and Canal 3.

Impairment Losses on Investments

For the year ended December 31, 2019, the Company recorded other-than-temporary impairment losses of $108 million, compared to $15 million recorded in the same period in 2018, as further described in Item 15 — Note 11, *Asset Impairments*, to the Consolidated Financial Statements.

Other Income, Net

Other income increased by $48 million for the year ended December 31, 2019, compared to the same period in 2018, primarily due to the loss on deconsolidation of Ivanpah in 2018.

Loss on Debt Extinguishment

A loss on debt extinguishment of $51 million was recorded for the year ended December 31, 2019, driven by the redemption of the Senior Notes, due 2024, and the repayment of the 2023 Term Loan Facility.

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.

Interest Expense

Interest expense decreased by $70 million for the year ended December 31, 2019, compared to the same period in 2018, due to the following:

		(In millions)
Decrease related to the debt reduction of $1.2 billion and refinancing $2.4 billion of debt at lower interest rates in 2019 and 2018	$	(66)
Decrease related to the deconsolidations of Ivanpah and Agua Caliente in 2018		(27)
Increase in derivative interest expense due to the termination of interest rate swaps in 2019 of $39 million partially offset by settlement of in-the-money interest rate swaps of $25 million		14
Increase due to California property tax indemnification accretion		7
Increase due to the amortization of the premium on the Convertible Senior Notes due 2048 that were issued in the second quarter of 2018		5
Other		(3)
Decrease in interest expense	$	(70)

Income Tax (Benefit)/Expense

For the year ended December 31, 2019, NRG recorded an income tax benefit of $3.3 billion on pre-tax income of $786 million. For the same period in 2018, NRG recorded income tax expense of $7 million on pre-tax income of $467 million. The effective tax rate was (424.2)% and 1.5% for the years ended December 31, 2019 and 2018, respectively. The large benefit for the year ended December 31, 2019 is due to a $3.5 billion release of the Company's valuation allowance. Refer to the section entitled Critical Accounting Policies and Estimates – *Income Taxes and Valuation Allowance for Deferred Tax Assets* and Item 15 – Note 20, *Income Taxes*, to the Consolidated Financial Statements for further discussion of the release in valuation allowance.

For the year ended December 31, 2019, NRG's overall effective tax rate was different than the federal statutory tax rate of 21% primarily due to a tax benefit from the release of the valuation allowance.

	Year Ended December 31,	
(In millions, except effective income tax rate)	**2019**	**2018**
Income from continuing operations before income taxes	$ 786	$ 467
Tax at federal statutory tax rate	165	98
State taxes	13	18
Deferred impact of state tax rate changes	12	—
Valuation allowance - current period activities	(3,492)	(106)
Permanent differences	(9)	7
Production tax credits ("PTCs")	—	(7)
Recognition of uncertain tax benefits	(10)	1
Alternative minimum tax ("AMT") refundable credit	—	(4)
Other	(13)	—
Income tax (benefit)/expense	$ (3,334)	$ 7
Effective income tax rate	(424.2)%	1.5 %

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

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

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**Change**
South Central	$ 28	$ 66	$ (38)
Yield Renewables Platform & Carlsbad	296	(292)	588
Genon	(3)	34	(37)
Income/(Loss) from discontinued operations, net of tax	**$ 321**	**$ (192)**	**$ 513**

Refer to Item 15 — Note 4, *Acquisitions, Discontinued Operations and Dispositions*, to the Consolidated Financial Statements for further discussion.

Consolidated Results of Operations for the years ended December 31, 2018 and 2017

The following table provides selected financial information for the Company:

	Year Ended December 31,		
(In millions, except otherwise noted)	**2018**	**2017**	**Change**
Operating Revenues			
Retail revenue	$ 6,894	$ 6,248	$ 646
Energy revenue[a]	1,496	1,612	(116)
Capacity revenue[a]	825	672	153
Mark-to-market for economic hedging activities	(130)	252	(382)
Contract amortization	—	(1)	1
Other revenues[a][b]	393	291	102
Total operating revenues	9,478	9,074	404
Operating Costs and Expenses			
Cost of sales[c]	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/(losses) of unconsolidated affiliates	9	(14)	23
Impairment losses on investments	(15)	(79)	64
Other income, net	18	51	(33)
Loss on debt extinguishment	(44)	(49)	5
Interest expense	(483)	(557)	74
Total other expense	(515)	(648)	133
Loss from Continuing Operations Before Income Taxes	467	(1,389)	1,856
Income tax expense/(benefit)	7	(44)	(51)
Net Income/(Loss) from Continuing Operations	460	(1,345)	1,805
Loss from discontinued operations, net of 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 realized and unrealized trading gains and losses
(c) Includes amortization of SO_2 and NO_x credits and excludes amortization of RGGI

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 for the years ended December 31, 2018 and 2017 based on the Company's current view of reportable segments:

	Year Ended December 31, 2018				
($ in millions, except otherwise noted)	**Texas**	**East**	**West/Other[a]**	**Corporate/Eliminations**	**Total**
Retail revenue	$ 5,856	$ 1,039	$ —	$ (1)	$ 6,894
Energy revenue[b]	371	546	566	13	1,496
Capacity revenue	—	746	79	—	825
Mark-to-market for economic hedging activities	(77)	(35)	(5)	(13)	(130)
Other revenue	251	75	84	(17)	393
Operating revenue	6,401	2,371	724	(18)	9,478
Cost of fuel	(734)	(308)	(250)	(6)	(1,298)
Purchased power[c]	(1,397)	(621)	(1)	(7)	(2,026)
Other costs of sales[c][d][e]	(2,180)	(335)	(37)	(2)	(2,554)
Mark-to-market for economic hedging activities	169	(37)	(1)	13	144
Contract and emission credit amortization	(26)	—	(1)	—	(27)
Gross margin	$ 2,233	$ 1,070	$ 434	$ (20)	$ 3,717
Less: Mark-to-market for economic hedging activities, net	92	(72)	(6)	—	14
Less: Contract and emission credit amortization, net	(26)	—	(1)	—	(27)
Economic gross margin	$ 2,167	$ 1,142	$ 441	$ (20)	$ 3,730

[a] Includes BETM, Agua Caliente and Ivanpah, which were sold or deconsolidated as of July, August and April 2018, respectively

[b] Intercompany sales of $1,173 million and $(32) million were eliminated within the Texas and East segments, respectively

[c] Includes $216 million total in purchased power and other cost of sales in the East that is not related to retail activities

[d] Includes capacity and emissions credits

[e] Includes $1,961 million and $4 million of electric TDSP charges for Texas and East, respectively

Business Metrics	**Texas**	**East**	**West/Other**	**Total**
Mass Market electricity sales volume (GWh)	37,846	7,968		45,814
C&I electricity sales volume (GWh)	20,192	984		21,176
Natural gas retail sales volumes (MDth)		11,253		11,253
Average retail Mass Market customer count (in thousands)	2,209	854		3,063
Ending retail Mass Market customer count (in thousands)	2,318	1,002		3,320
GWh sold[a]	42,701	14,020	10,968	67,689
GWh generated[b]	38,214	10,119	10,970	59,303

[a] Includes 31,198 GWh of intercompany sales within Texas

[b] Includes owned generation and excludes equity investments

($ in millions, except otherwise noted)	Year Ended December 31, 2017				
	Texas	East	West/Other	Corporate/Eliminations	Total
Retail revenue	$ 5,455	$ 785	$ —	$ 8	$ 6,248
Energy revenue[a]	374	599	639	—	1,612
Capacity revenue	—	587	88	(3)	672
Mark-to-market for economic hedging activities	285	(7)	(29)	3	252
Contract amortization	(1)	—	—	—	(1)
Other revenue	205	45	90	(49)	291
Operating revenue	6,318	2,009	788	(41)	9,074
Cost of fuel	(735)	(329)	(214)	—	(1,278)
Purchased power[b]	(1,312)	(479)	(1)	—	(1,792)
Other costs of sales[c][d]	(2,091)	(256)	(40)	25	(2,362)
Mark-to-market for economic hedging activities	(56)	7	6	(3)	(46)
Contract and emission credit amortization	(30)	—	(4)	—	(34)
Gross margin	$ 2,094	$ 952	$ 535	$ (19)	$ 3,562
Less: Mark-to-market for economic hedging activities, net	229	—	(23)	—	206
Less: Contract and emission credit amortization, net	(31)	—	(4)	—	(35)
Economic gross margin	$ 1,896	$ 952	$ 562	$ (19)	$ 3,391

[a] Intercompany sales of $1,054 million and $35 million were eliminated within the Texas and East segments, respectively

[b] Includes $197 million in the East that is not related to retail activities

[c] Includes capacity and emissions credits

[d] Includes $1,888 million of electric TDSP charges in Texas

Business Metrics	Texas	East	West/Other	Total
Mass Market electricity sales volume (GWh)	36,169	6,221		42,390
C&I electricity sales volume (GWh)	19,586	814		20,400
Natural gas retail sales volumes (MDth)		3,212		3,212
Average retail Mass Market customer count (in thousands)	2,177	686		2,863
Ending retail Mass Market customer count (in thousands)	2,188	688		2,876
GWh sold[a]	42,662	16,543	11,380	70,585
GWh generated[b]	38,694	9,944	11,394	60,032

[a] Includes 30,054 GWh of intercompany sales within Texas

[b] Includes owned generation and excludes equity investments

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

	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/Other[a]	Texas	East	West/Other[a]	Texas	East	West/Other[a]	Texas	East	West/Other[a]	Texas	East	West/Other[a]
2018															
CDDs[b]	3,130	1,430	1,975	228	111	126	1,657	919	1,189	1,101	364	599	144	36	61
HDDs[b]	1,875	2,349	2,090	815	1,719	808	1	37	9	91	561	207	968	32	1,066
2017															
CDDs	3,067	1,234	1,078	311	103	66	1,568	739	802	966	355	207	223	37	3
HDDs	1,269	4,288	2,108	665	1,644	670	1	55	12	32	452	307	572	2,137	1,119
10 year average															
CDDs	3,023	1,228	890	264	74	63	1,654	772	656	1,004	350	168	101	32	3
HDDs	1,728	4,647	2,272	695	1,628	800	3	63	17	56	508	351	974	2,448	1,104

[a] The West/Other weather metrics are comprised of the average of the CDD and HDD regional results for the West - California and West - South Central regions

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

Gross margin and economic gross margin

Gross margin increased $155 million and economic gross margin increased $339 million for the year ended December 31, 2018, compared to the same period in 2017. The detail by segment is as follows:

Texas

		(In millions)
Higher gross margin due to a 11% increase in average realized prices on generation sold[a]	$	153
Higher gross margin on retail sales driven by margin enhancement initiatives enhancing customer product, retention, term and mix of $3.50 per MWh, or $190 million, partially offset by higher supply costs due to increased power prices of approximately $2.50 MWh, or $143 million[a]		47
Higher gross margin on retail sales from the favorable impact of weather due to $36 million from an increase in load in 2018 of 1,636,000 MWh, partially offset by an unfavorable impact of $11 million from selling back additional excess supply in 2018, as well as $16 million due to the impacts of Hurricane Harvey in 2017		41
Higher gross margin from sales of NOx emission credits		36
Higher gross margin driven by higher retail sales volumes from the XOOM acquisition in June 2018		10
Higher gross margin from market 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		(6)
Increase in economic gross margin	$	271
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		(137)
Increase in contract and emission credit amortization		5
Increase in gross margin	$	139

[a] Includes effects of intercompany sales and purchases that were eliminated within the segment

East

		(In millions)
Higher gross margin due to a 32% increase in PJM generation capacity prices and a 51% increase in ISO-NE generation capacity prices	$	128
Higher gross margin driven by higher retail sales volumes from the XOOM acquisition		50
Higher gross margin due to an increase in capacity revenues from Business Solutions mainly due to approximately 1,600 additional MWs sold and margin enhancements from the sale of additional capacity of $11 million		36
Higher gross margin from market optimization activities		34
Higher gross margin due to 2017 lower cost of market adjustment for fuel inventory		31
Higher gross margin from retail sales driven by margin enhancement initiatives enhancing customer product, retention, term, and mix of $2.00 per MWh, or $18 million, partially offset by higher supply costs driven by an increase in power prices of approximately $0.50 per MWh, or $4 million[a]		14
Higher gross margin from retail sales from the favorable impact of weather due to $8 million from an increase in load in 2018 of 257,000 MWh, partially offset by an unfavorable impact of $3 million from selling back additional excess supply in 2018		5
Higher gross margin due to margin enhancement initiatives from reduced fuel supply costs		4
Lower gross margin mainly due to an 11% decrease in average realized prices on generation sold, primarily at Midwest Generation[a]		(45)
Lower gross margin driven by a 26% decrease in realized generation capacity pricing in New York		(39)
Lower gross margin from retail sales due to decreased load contract volumes coupled with lower prices		(29)
Other		1
Increase in economic gross margin	$	190
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		(72)
Increase in gross margin	$	118

[a] Includes effects of intercompany sales and purchases that were eliminated within the segment

West/Other

	(In millions)
Lower gross margin primarily due to the deconsolidations of Ivanpah and Agua Caliente in April 2018 and August 2018, respectively	$ (123)
Lower gross margin at Sunrise in 2018 due to planned major maintenance activities that extended into a forced outage	(17)
Lower gross margin driven by the expiration of the Long Beach generation capacity toll in July 2017	(12)
Higher gross margin due to insurance proceeds from outages in 2018, partially offset by business interruption proceeds in 2017	10
Higher gross margin as a result of trading activity at BETM	8
Higher gross margin due to the extended outage of Cottonwood related to Hurricane Harvey in 2017	8
Higher gross margin due to a final construction completion payment earned related to Buckthorn Solar in April 2018 and construction management fees earned in 2018 for Canal 3	7
Other	(2)
Decrease in economic gross margin	$ (121)
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	17
Increase in contract and emission credit amortization	3
Decrease in gross margin	$ (101)

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 $192 million in 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 segment are as follows:

	Year Ended December 31, 2018				
(In millions)	Texas	East	West/Other	Eliminations	Total
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (56)	$ (26)	$ 7	$ (2)	$ (77)
Net unrealized losses on open positions related to economic hedges	(21)	(9)	(12)	(11)	(53)
Total mark-to-market losses in operating revenues	$ (77)	$ (35)	$ (5)	$ (13)	$ (130)
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized gains/(losses) on settled positions related to economic hedges	$ 15	$ (11)	$ (2)	$ 2	$ 4
Reversal of acquired (gain)/loss positions related to economic hedges	(11)	1	—	—	(10)
Net unrealized gains/(losses) on open positions related to economic hedges	165	(27)	1	11	150
Total mark-to-market gains/(losses) in operating costs and expenses	$ 169	$ (37)	$ (1)	$ 13	$ 144

(In millions)	Year Ended December 31, 2017 Texas	East	West/Other	Eliminations	Total
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 196	$ (32)	$ (34)	$ —	$ 130
Net unrealized gains on open positions related to economic hedges	89	25	5	3	122
Total mark-to-market gains/(losses) in operating revenues	$ 285	$ (7)	$ (29)	$ 3	$ 252
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ (83)	$ (4)	$ 4	$ —	$ (83)
Net unrealized gains on open positions related to economic hedges	27	11	2	(3)	37
Total mark-to-market (losses)/gains in operating costs and expenses	$ (56)	$ 7	$ 6	$ (3)	$ (46)

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, 2018 and 2017. 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.

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

Operations and Maintenance Expense

(In millions)	Texas	East	West/Other	Corporate	Eliminations	Total
Year Ended December 31, 2018	$ 593	$ 402	$ 93	$ 3	$ (8)	$ 1,083
Year Ended December 31, 2017	585	365	141	14	(8)	1,097

Operations and maintenance expense 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 due to cost efficiencies as a result of the Transformation Plan[a]	$	(70)
Decrease due to the deconsolidations of Ivanpah and Agua Caliente in April 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 acquisition of XOOM		7
Other		7
Decrease in operations and maintenance expense	$	(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

(In millions)	Texas	East	West/Other	Total
Year Ended December 31, 2018	$ 162	$ 77	$ 25	$ 264
Year Ended December 31, 2017	160	82	35	277

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

Depreciation and Amortization

(In millions)	Texas	East	West/Other	Corporate	Eliminations	Total
Year Ended December 31, 2018	$ 156	$ 105	$ 127	$ 33	$ —	$ 421
Year Ended December 31, 2017	258	112	194	35	(3)	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 deconsolidations of Ivanpah and Agua Caliente in 2018.

Impairment Losses

During 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 11, *Asset Impairments*, to the Consolidated Financial Statements.

During the year ended December 31, 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 11, *Asset Impairments*, and Note 12, *Goodwill and Other Intangibles*, to the Consolidated Financial Statements.

Selling, General and Administrative Expenses

(In millions)	Texas	East	West/Other	Corporate	Total
Year Ended December 31, 2018	$ 456	$ 241	$ 56	$ 46	$ 799
Year Ended December 31, 2017	417	183	69	167	836

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

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

Other Income - Affiliate

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

Gain/(Loss) 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 11, *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.

Interest Expense

NRG's interest expense decreased by $74 million for the year ended December 31, 2018, compared to the same period in 2017, primarily due to lower debt balances resulting in less interest.

Income Tax Expense

For the year ended December 31, 2018, NRG recorded an income tax expense of $7 million on a pre-tax income of $467 million. For the same period in 2017, NRG recorded an income tax benefit of $44 million on 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 the establishment of the previously sequestered ATM credit receivable, partially offset by current state tax expense.

	Year Ended December 31,	
(In millions, except as otherwise noted)	**2018**	**2017**
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	—
PTCs	(7)	(8)
Recognition of uncertain tax benefits	1	(5)
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. 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 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 4 *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 or in part by NRG Yield, Inc.'s share of income for the periods. As a result of the disposition of NRG Yield Inc. and its Renewables Platform, the Company did not have material net gains or losses attributable to noncontrolling interests in 2018 nor does it anticipate material net gains or losses attributable to noncontrolling interests in the future.

Liquidity and Capital Resources

Liquidity Position

As of December 31, 2019 and 2018, NRG's liquidity, excluding collateral funds deposited by counterparties, was approximately $2.1 billion and $2.0 billion, respectively, comprised of the following:

	As of December 31,	
(In millions)	**2019**	**2018**
Cash and cash equivalents:	$ 345	$ 563
Restricted cash - operating	4	6
Restricted cash - reserves [(a)]	4	11
Total	353	580
Total credit facility availability	1,794	1,397
Total liquidity, excluding collateral funds deposited by counterparties	$ 2,147	$ 1,977

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

For the year ended December 31, 2019, total liquidity, excluding collateral funds deposited by counterparties, increased by $170 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, 2019 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 13, 2019, Moody's upgraded the NRG corporate family rating to Ba1 and senior unsecured rating to Ba2. The agency affirmed the company's senior secured rating at Baa3.

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

	S&P	Moody's
NRG Energy, Inc.	BB Positive	Ba1 Positive
3.75% Senior Secured Notes, due 2024	BBB-	Baa3
7.25% Senior Notes, due 2026	BB	Ba2
6.625% Senior Notes, due 2027	BB	Ba2
5.75% Senior Notes, due 2028	BB	Ba2
4.45% Senior Secured Notes, due 2029	BBB-	Baa3
5.25% Senior Notes, due 2029	BB	Ba2
Revolving Credit Facility, due 2024	BBB-	Baa3

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 and financing arrangements. As described in Item 15 — Note 13, *Debt and Finance Leases,* to the Consolidated Financial Statements, the Company's financing arrangements consist mainly of the Senior Credit Facility, the Senior Notes and the Senior Secured Notes.

The Company's requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (i) market operations activities; (ii) debt service obligations, as described more fully in Item 15 — Note 13, *Debt and Finance Leases*, to the Consolidated Financial Statements; (iii) capital expenditures, including environmental; and (iv) allocations in connection with return of capital and dividend payments to shareholders as described in Item 15 — Note 16, *Capital Structure*, to the Consolidated Financial Statements, acquisition opportunities, and debt repayments.

Issuance of 2029 Senior Notes

On May 14, 2019, NRG issued $733 million of aggregate principal amount at par of 5.25% senior unsecured notes due 2029. The proceeds from the issuance of the 2029 Senior Notes were utilized to redeem the Company's remaining $733 million of 6.25% Senior Notes due 2024.

Issuance of 2024 and 2029 Senior Secured Notes

On May 28, 2019, NRG issued $1.1 billion of aggregate principal amount of senior secured first lien notes, consisting of $600 million 3.75% senior secured first lien notes due 2024 and $500 million 4.45% senior secured first lien notes due 2029, at a discount. The proceeds from the issuance of the Senior Secured Notes, together with cash on hand, were used to repay the Company's 2023 Term Loan Facility.

2023 Term Loan Facility

On May 28, 2019, the Company repaid its $1.7 billion 2023 Term Loan Facility using the proceeds from the issuance of the Senior Secured Notes, as well as cash on hand, resulting in a decrease of $594 million to long-term debt outstanding. The Company recorded a loss on debt extinguishment of $17 million, which included the write-off of previously deferred debt issuance costs of $13 million. As a result of the repayment of the outstanding 2023 Term Loan Facility, the Company terminated the related interest rate swap agreements, which were in-the-money, and received $25 million that was recorded as a reduction to interest expense.

Revolving Credit Facility Modification

On May 28, 2019, the Company amended its existing credit agreement to, among other things, (i) provide for a $184 million increase in revolving commitments, resulting in aggregate revolving commitments under the amended credit agreement equal to $2.6 billion, (ii) extend the maturity date of the revolving loans and commitments under the amended credit agreement to May 28, 2024, (iii) provide for a release of the collateral securing the amended credit agreement if NRG obtains an investment grade rating from two out of the three rating agencies, subject to an obligation to reinstate the collateral if such rating agencies withdraw NRG’s investment grade rating or downgrade NRG’s rating below investment grade, (iv) reduce the applicable margins for borrowings under (a) ABR Revolving Loans from 1.25% to 0.75% and (b) Eurodollar Revolving Loans from 2.25% to 1.75%, (v) add a sustainability-linked pricing metric that permits an interest rate adjustment tied to NRG meeting targets related to environmental sustainability and (vi) make certain other changes to the existing covenants. As of December 31, 2019, $83 million of borrowings were outstanding under the Revolving Credit Facility.

Agua Caliente Borrower I - Non-Recourse Debt

On October 21, 2019, the Company repaid the outstanding amount on the Agua Caliente Borrower I notes at 102% plus accrued interest through the payment date.

Balance Sheet Target Ratio

NRG revised its credit metrics target to 2.5x -2.75x net debt / adjusted EBITDA[a] in the first quarter of 2019 in order to further strengthen its balance sheet and improve credit ratings by reducing leverage. As discussed above, during the second quarter of 2019, the Company reduced total outstanding debt by $594 million with the repayment of the 2023 Term Loan facility.

Petra Nova Debt Repayment

During the third quarter of 2019, NRG contributed approximately $95 million in cash to Petra Nova and posted a $12 million letter of credit to cover certain project debt reserve requirements. The cash portion of the contribution was used by Petra Nova to prepay a significant portion of the project debt. As a result, the financial guarantees previously provided by NRG were canceled and the remaining project debt became non-recourse to NRG.

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

Debt Service Obligations

Principal payments on debt as of December 31, 2019 are due in the following periods:

(In millions) Description	2020	2021	2022	2023	2024	Thereafter	Total
Recourse Debt:							
Senior notes, due 2026	$ —	$ —	$ —	$ —	$ —	$ 1,000	$ 1,000
Senior notes, due 2027	—	—	—	—	—	1,230	1,230
Senior notes, due 2028	—	—	—	—	—	821	821
Senior notes, due 2029	—	—	—	—	—	733	733
Convertible Senior Notes, due 2048	—	—	—	—	—	575	575
Senior Secured First Lien Notes, due 2024	—	—	—	—	600	—	600
Senior Secured First Lien Notes, due 2029	—	—	—	—	—	500	500
Revolving Credit Facility	83	—	—	—	—	—	83
Tax-exempt bonds	—	—	—	—	—	466	466
Subtotal Recourse Debt	83	—	—	—	600	5,325	6,008
Non-Recourse Debt:							
Other	5	6	5	4	4	10	34
Subtotal Non-Recourse Debt	5	6	5	4	4	10	34
Total Debt	$ 88	$ 6	$ 5	$ 4	$ 604	$ 5,335	$ 6,042

In addition to the debt shown in the above table, NRG had issued $723 million of letters of credit under the Company's $2.6 billion Revolving Credit Facility as of December 31, 2019.

Market Operations

The Company's market 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, 2019, market operations had total cash collateral outstanding of $190 million and $694 million outstanding in letters of credit to third parties primarily to support its market activities for both wholesale and retail transactions. As of December 31, 2019, total funds deposited by counterparties was $32 million in cash and $102 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.

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of property and assets owned by NRG and the guarantors of its senior debt. 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 a 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, 2019, all hedges under the first liens were in-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MW hedged against the Company's coal and nuclear assets and as a percentage relative to the Company's coal and nuclear capacity under the first lien structure as of December 31, 2019:

Equivalent Net Sales Secured by First Lien Structure (a)	2020	2021	2022	2023
In MW	642	644	699	753
As a percentage of total net coal and nuclear capacity (b)	14%	14%	15%	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

Stream Energy Acquisition

On August 1, 2019, the Company completed the acquisition of Stream Energy's retail electricity and natural gas business operating in 9 states and Washington, D.C. for $329 million, including working capital and other adjustments of approximately $29 million. The acquisition increased NRG's retail portfolio by approximately 600,000 RCEs or 450,000 customers.

Small Book Acquisitions

During 2019, the Company acquired several books of customers totaling approximately 72,000 customers for $17 million, of which $13 million was paid in 2019. During 2018, the Company acquired several books of customers totaling approximately 115,000 customers, along with brand names, for $44 million, of which $40 million was paid in 2018, $2 million was paid in 2019 and $2 million was prepaid in 2017. The majority of the purchase price for the 2019 and 2018 book acquisitions were allocated to acquired intangibles.

Asset Sale Proceeds

The following table summarizes the approximate cash proceeds received from sale transactions and related financings, net of working capital and other adjustments, completed by the Company during the years ended December 31, 2019 and 2018:

(In millions)	2019	2018
South Central Portfolio	$ 962	$ —
Carlsbad	396	—
Guam	8	—
NRG Yield, Inc and Renewables Platform	—	1,348
Canal 3 (a)	—	167
UPMC Thermal Project (b)	—	84
BETM	—	70
Buckthorn Solar (b)	—	42
Other	14	12
Cash proceeds from sales transactions	$ 1,380	$ 1,723

(a) In addition to cash proceeds from sale, amount includes $151 million related to a financing arrangement prior to the sale
(b) Sale of assets to NRG Yield, Inc., prior to discontinued operations

Capital Expenditures

The following table summarizes the Company's capital expenditures for maintenance, environmental, and growth investments for the year ended December 31, 2019:

(In millions)	Maintenance	Environmental	Growth Investments[a]	Total
Texas	$ 102	$ 1	$ 34	$ 137
East	15	2	12	29
West/Other	25	—	—	25
Corporate	14	—	23	37
Total cash capital expenditures for the year ended December 31, 2019	156	3	69	228
Stream acquisition	—	—	326	326
Other investments[b]	—	—	240	240
Total capital expenditures and investments, net of financings	$ 156	$ 3	$ 635	$ 794

[a] For the year ended December 31, 2019, the Company's growth investments capital expenditures included $51 million for cost-to-achieve projects associated with the Transformation Plan and $18 million for the Company's other growth projects

[b] Other investments include acquisitions, cost-to-achieve expenses, integration costs, and equity investments

Environmental Capital Expenditures Estimate

NRG estimates that environmental capital expenditures from 2020 through 2024 required to comply with environmental laws will be approximately $40 million. These costs are primarily associated with the cost of adding NO_x controls in Connecticut and water and landfill projects at W.A. Parish.

The table below summarizes the status of NRG's coal fleet with respect to air quality controls. NRG uses an integrated approach to fuels, controls and emissions markets to meet environmental requirements.

		SO_2		NO_x		Mercury		Particulate	
Units	State	Control Equipment	Install Date	Control Equipment	Install Date	Control Equipment	Install Date	Control Equipment	Install Date
Indian River 4	DE	CDS	2011	LNBOFA/SCR	1999/2011	ACI/CDS/FF	2008/2011	ESP/FF	1980/2011
Limestone 1-2	TX	FGD	1985-86	LNBOFA	2002/2003	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 by region:

(In millions)	Texas	East	Total
2020	$ 3	$ 4	$ 7
2021	14	10	24
2022	6	3	9
2023	—	—	—
2024	—	—	—
Total	$ 23	$ 17	$ 40

Share Repurchases

In 2018, the Company's board of directors authorized the Company to repurchase $1.5 billion of its common stock. Repurchases of $1.25 billion were executed in 2018 with the remaining $0.25 billion completed in the first quarter of 2019. In 2019, the Company's board of directors authorized the Company to repurchase additional $1.25 billion of its common stock, which was completed as of February 27, 2020. See Item 15 — Note 16, *Capital Structure*, to the Consolidated Financial Statements for additional discussion.

Common Stock Dividends

The Company returned $32 million of capital to shareholders in the year ended 2019 through a $0.12 dividend per common share.

Beginning in the first quarter of 2020, NRG increased the annual dividend to $1.20 per share from $0.12 per share and expects to target an annual dividend growth rate of 7-9% per share in subsequent years.

On January 21, 2020, NRG declared a quarterly dividend on the Company's common stock of $0.30 per share, or $1.20 per share on an annualized basis, payable on February 18, 2020, to stockholders of record as of February 3, 2020. The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws and regulations.

Cash Flow Discussion

2019 compared to 2018

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

	Year ended December 31,		
(In millions)	**2019**	**2018**	**Change**
Net cash provided by operating activities	$ 1,413	$ 1,377	$ 36
Net cash provided/(used) by investing activities	556	(205)	761
Net cash used by financing activities	(2,148)	(1,526)	(622)

Net Cash Provided By Operating Activities

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

	(In millions)
Change in cash provided by discontinued operations	$ (366)
Increase in operating income adjusted for other non-cash items	230
Changes in cash collateral in support of risk management activities due to change in commodity prices	210
GenOn settlement in July 2018	63
Other changes in working capital	(101)
	$ 36

Net Cash Provided By Investing Activities

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

		(In millions)
Decrease in cash used by discontinued operations	$	724
Cash removed in 2018 due to deconsolidation of Agua Caliente and Ivanpah projects		268
Decrease in capital expenditures primarily driven by construction projects in 2018		160
Increase in proceeds received from sales of nuclear decommissioning trust fund securities, net of purchases		24
Decrease in contributions to discontinued operations		16
Decrease in proceeds from sale of assets and discontinued operations		(271)
Increase in cash paid for acquisitions primarily due to Stream Energy acquisition in 2019		(112)
Change in investments in unconsolidated affiliates		(52)
Other		4
	$	761

Net Cash Used By Financing Activities

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

		(In millions)
Increase in payments of short and long-term debt	$	(837)
Change in cash provided by discontinued operations		(428)
Increase in payments for treasury stock		(190)
Increase in payments of debt extinguishment costs and deferred issuance costs		(10)
Increase in proceeds from issuance of short and long-term debt		816
Decrease in distributions to noncontrolling interests from subsidiaries		14
Other		13
	$	(622)

NOLs, Deferred Tax Assets and Uncertain Tax Position Implications

As of December 31, 2019, the Company had domestic pre-tax book income of $771 million and foreign pre-tax book income of $15 million. For the year ended December 31, 2019, the Company utilized NOLs of $593 million due to current year taxable income. As of December 31, 2019, the Company has cumulative U.S. federal NOL carryforwards of $10.1 billion, which will begin expiring in 2031 and cumulative state NOL carryforwards of $5.5 billion. NRG also has cumulative foreign NOL carryforwards of $357 million, which do not have an expiration date. In addition to the above NOLs, NRG has a $361 million indefinite carryforward for interest deductions, as well as $384 million of tax credits to be utilized in future years. As a result of the Company's tax position, including the utilization of federal and state NOLs, and based on current forecasts, the Company anticipates income tax payments, primarily due to state and local jurisdictions, of up to $16 million in 2020. See Item 15 — Note 20, *Income Taxes*, for further discussion regarding the release of the valuation allowance.

The Company has recorded as of December 31, 2019 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 2020 through 2022 pursuant to the 50% annual limitation as enacted by the Tax Act upon repeal of corporate AMT effective January 1, 2018. Of these amounts, short-term and long-term payables of $11 million each are due to GenOn for their share of the minimum tax credits.

In addition to these amounts, the Company has $15 million of tax effected uncertain state tax benefits for which the Company has recorded a non-current tax liability of $17 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 2016. With few exceptions, state and local income tax examinations are no longer open for years before 2011.

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 market 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 27, *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, 2019, 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. Ivanpah 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 $866 million as of December 31, 2019. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Item 15 — Note 17, *Investments Accounted for by the Equity Method and Variable Interest Entities*, to the Consolidated Financial Statements for additional discussion.

Contractual Obligations and Market Commitments

NRG has a variety of contractual obligations and other market 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 13, *Debt and Finance Leases*, Note 23, *Commitments and Contingencies*, and Note 27, *Guarantees*, to the Consolidated Financial Statements for additional discussion.

(In millions)	By Remaining Maturity at December 31, 2019				
Contractual Cash Obligations	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total (a)**
Long-term debt (including estimated interest)	$ 436	$ 705	$ 1,281	$ 6,912	$ 9,334
Operating leases	96	174	160	296	726
Fuel purchase and transportation obligations	124	198	115	139	576
Purchased power commitments(b)	35	117	112	349	613
Pension minimum funding requirement (c)	54	54	42	53	203
Other postretirement benefits minimum funding requirement (d)	7	11	11	17	46
Other liabilities (e)	45	57	40	125	267
Total	$ 797	$ 1,316	$ 1,761	$ 7,891	$ 11,765

(a) Excludes $15 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 $728 million of asset retirement obligations that are discussed in Item 15 — Note 14, *Asset Retirement Obligations*, to the Consolidated Financial Statements

(b) Includes purchase power commitments and renewable minimum purchase power commitments under PPAs

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

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

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

(In millions)	By Remaining Maturity at December 31, 2019				
Guarantees	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total**
Letters of credit and surety bonds(a)	$ 878	$ 115	$ 31	$ —	$ 1,024
Asset sales guarantee obligations	4	490	—	204	698
Other guarantees	77	5	—	206	288
Total guarantees	$ 959	$ 610	$ 31	$ 410	$ 2,010

(a) Guarantees as of December 31, 2019 include $14 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 power plants or retail load obligations.

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, 2019, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at December 31, 2019. For a full discussion of the Company's valuation methodology of its contracts, see *Derivative Fair Value Measurements* in Item 15 — Note 5, *Fair Value of Financial Instruments*, to the Consolidated Financial Statements.

Derivative Activity Gains/(Losses)	**(In millions)**
Fair value of contracts as of December 31, 2018	$ 104
Contracts realized or otherwise settled during the period	(105)
Contracts acquired during the period	(12)
Changes in fair value	80
Fair value of contracts as of December 31, 2019	$ 67

(In millions)	**Fair Value of Contracts as of December 31, 2019**				
	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**
Level 1	$ (31)	$ (27)	$ (2)	$ 1	$ (59)
Level 2	56	49	(7)	(10)	88
Level 3	54	(2)	1	(15)	38
Total	$ 79	$ 20	$ (8)	$ (24)	$ 67

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, 2019, NRG's net derivative asset was $67 million, a decrease to total fair value of $37 million as compared to December 31, 2018. This decrease was primarily driven by losses in trades settled and contracts acquired during the period, partially offset by increases in change in fair value 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 an increase of approximately $41 million in the net value of derivatives as of December 31, 2019.

The impact of a $0.50 per MMBtu decrease in natural gas prices across the term of the derivative contracts would result in a decrease of approximately $36 million in the net value of derivatives as of December 31, 2019.

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 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

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. These estimations are considered to be critical accounting estimates.

Upon repayment of the Term Loan in 2019, all of the Company's interest rate swaps were terminated. In order to qualify the derivative instruments for hedged transactions prior to termination, NRG estimated the forecasted borrowings for interest rate swaps occurring within a specified time period. Judgments related to the probability of forecasted borrowings were 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.

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 expected load requirements, 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, 2019, NRG’s deferred tax assets were primarily the result of U.S. federal and state NOLs, the difference between book and tax basis in property, plant, and equipment, and tax credit carryforwards. The realization of deferred tax assets is dependent upon the Company's ability to generate sufficient future taxable income during the periods in which those temporary differences become deductible, prior to the expiration of the tax attributes. The evaluation of deferred tax assets requires judgment in assessing the likely future tax consequences of events that have been recognized in the Company's financial statements or tax returns and forecasting future profitability by tax jurisdiction.

A valuation allowance of $242 million and $3.8 billion was recorded against NRG’s gross deferred tax asset balance as of December 31, 2019, and December 31, 2018, respectively. During the year ended December 31, 2019, NRG released the majority of its valuation allowance against its U.S. federal and state deferred tax assets, resulting in a non-cash benefit to income tax expense of approximately $3.5 billion.

The Company evaluates its deferred tax assets quarterly on a jurisdictional basis to determine whether adjustments to the valuation allowance are appropriate considering changes in facts or circumstances. As of each reporting date, management considers new evidence, both positive and negative, when determining the future realization of the Company’s deferred tax assets. In making the determination to release the majority of the valuation allowance as of December 31, 2019, the Company evaluated a number of factors, including its recent history of pre-tax earnings, utilization of $593 million of NOLs in 2019, as well as its forecasted future pre-tax earnings. Based on this evaluation, the Company determined that its future U.S. federal tax benefits are more-likely-than-not to be realized. Given the Company’s current level of pre-tax earnings and forecasted future pre-tax earnings, the Company expects to generate income before taxes in the U.S. in future periods at a level that would fully utilize its U.S. federal NOL carryforwards and the majority of its state NOL carryforwards prior to their expiration.

NRG continues to maintain a valuation allowance of approximately $242 million as of December 31, 2019 against net deferred tax assets consisting of state net operating losses and foreign NOL carryforwards in jurisdictions where the Company does not currently believe that the realization of its deferred tax assets is more likely than not.

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 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 2016. With few exceptions, state and local income tax examinations are no longer open for years before 2011.

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, 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 impact 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.

As of December 31, 2019, the Company recorded impairment losses of approximately $5 million, excluding impairment losses on equity and cost method investments discussed below. 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 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, 2019, the Company recorded impairment losses on its equity and cost method investments, primarily Petra Nova, of $108 million due to declines in value.

Goodwill and Other Intangible Assets

At December 31, 2019, NRG reported goodwill of $579 million, consisting of $165 million associated with the acquisition of Midwest Generation and $414 million for retail business acquisitions, including XOOM and Stream Energy.

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 a quantitative assessment for each of the Company's reporting units, including Texas (Texas segment), East Retail (East segment) and Midwest Generation (East segment). 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 each reporting unit's cash flow exceeded its carrying value and, as such, the Company concluded that goodwill associated with each of the reporting units was not impaired as of December 31, 2019.

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

- The Company applied a discounted cash flow methodology to the long-term budgets for the Midwest Generation plants, resulting in fair value over the carrying value of the reporting unit of 112%. 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 next five years 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 budgets is based on an hourly dispatch that simulates dispatch of each unit into the power market. The dispatch simulation is based on power prices, fuel prices, and the physical and economic characteristics of each plant
- The Company applied a discounted cash flow methodology to the long-term budgets for the Texas and East Retail reporting units. The significant assumptions used to derive the long-term budgets used in the income approach are affected by the following key inputs: terminal values utilizing assumed growth rates and discount rates that reflect the inherent cash flow risk.

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 23, *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.

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, 2019, 2018, and 2017

Consolidated Statements of Comprehensive Income/(Loss) — Years ended December 31, 2019, 2018, and 2017

Consolidated Balance Sheets — As of December 31, 2019 and 2018

Consolidated Statements of Cash Flows — Years ended December 31, 2019, 2018, and 2017

Consolidated Statements of Stockholders' Equity — Years ended December 31, 2019, 2018, and 2017

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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
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, 2019 and 2018, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, 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, 2019, 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 27, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Changes in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2019, the Company adopted Financial Accounting Standard Board (FASB) Accounting Standards Codification (ASC) Topic 842, *Leases*, and related amendments. As discussed in Note 3 to the consolidated financial statements, effective January 1, 2018, the Company adopted FASB ASC 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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Evaluation of the sufficiency of audit evidence obtained over operating revenues

As discussed in Note 3 to the consolidated financial statements, the Company had $9,821 million of operating revenues. Operating revenue is derived from various revenue streams in different geographic markets and the Company’s processes and related information technology (IT) systems used to record revenue differ for each of these revenue streams.

We identified the evaluation of the sufficiency of audit evidence over operating revenues as a critical audit matter which required a high degree of auditor judgment due to the number of revenue streams and IT systems involved in the revenue recognition process. This included determining the revenue streams over which procedures were to be performed and evaluating the nature and extent of evidence obtained over the individual revenue streams as well as operating revenue in the aggregate. It also included the involvement of IT professionals with specialized skills and knowledge to assist in the performance of certain procedures.

We, with the assistance of IT professionals, applied auditor judgment to determine the revenue streams over which procedures were performed as well as the nature and extent of such procedures. For each revenue stream over which procedures were performed, we tested certain internal controls over the Company’s revenue recognition processes; involved IT professionals, who assisted in testing certain IT applications used by the Company in its revenue recognition processes; and assessed the recorded revenue by selecting transactions and comparing the amounts recognized to underlying documentation, including contracts with customers. In addition, we evaluated the overall sufficiency of audit evidence obtained over operating revenues.

Evaluation of the realizability of deferred tax assets related to net operating loss carryforwards

As discussed in Notes 2 and 20 to the consolidated financial statements, the Company decreased its valuation allowance by $3.5 billion during the year ended December 31, 2019 resulting in $3.3 billion of net deferred tax assets as of December 31, 2019. The Company records a valuation allowance to reduce its deferred tax assets to an amount that is more than 50% likely of being realized. The Company considers both positive and negative evidence in evaluating the need for a valuation allowance, including cumulative pre-tax earnings or losses and forecasted future taxable income in each tax jurisdiction.

We identified the evaluation of the realizability of deferred tax assets related to net operating loss carryforwards as a critical audit matter. A high degree of auditor judgment was necessary to assess the consideration of positive and negative evidence, specifically the Company’s cumulative losses in recent years and the relevance of such losses to forecasted future taxable income. In addition, specialized skills were required to evaluate the Company’s interpretation of income tax regulations.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company’s income tax process, including controls related to the application of income tax regulations and the Company's consideration of positive and negative evidence. We assessed the utilization of net operating loss carryforwards in each tax jurisdiction before their scheduled expiration. We involved income tax professionals with specialized skills and knowledge, who assisted in evaluating the Company's interpretation of income tax regulations applied in its realizability analysis. We evaluated the Company’s consideration of positive and negative evidence in determining whether net deferred tax assets were more than 50% likely of being realized. This evaluation included considering the cumulative losses in recent years and evaluating the likelihood that those losses would reoccur and impact forecasted future taxable income.

/s/ KPMG LLP

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

Philadelphia, Pennsylvania
February 27, 2020, except for Notes 1, 2, 3, 4 and 19, as to which the date is May 7, 2020

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share amounts)	For the Year Ended December 31, 2019	2018	2017
Operating Revenues			
Total operating revenues	$ 9,821	$ 9,478	$ 9,074
Operating Costs and Expenses			
Cost of operations	7,303	7,108	6,886
Depreciation and amortization	373	421	596
Impairment losses	5	99	1,534
Selling, general and administrative	827	799	836
Reorganization costs	23	90	44
Development costs	7	11	22
Total operating costs and expenses	8,538	8,528	9,918
Other income - affiliate	—	—	87
Gain on sale of assets	7	32	16
Operating Income/(Loss)	1,290	982	(741)
Other Income/(Expense)			
Equity in earnings/(losses) of unconsolidated affiliates	2	9	(14)
Impairment losses on investments	(108)	(15)	(79)
Other income, net	66	18	51
Loss on debt extinguishment, net	(51)	(44)	(49)
Interest expense	(413)	(483)	(557)
Total other expense	(504)	(515)	(648)
Income/(Loss) from Continuing Operations Before Income Taxes	786	467	(1,389)
Income tax (benefit)/expense	(3,334)	7	(44)
Income/(Loss) from Continuing Operations	4,120	460	(1,345)
Income/(loss) from discontinued operations, net of income tax	321	(192)	(992)
Net Income/(Loss)	4,441	268	(2,337)
Less: Net income/(loss) attributable to noncontrolling interest and redeemable interests	3	—	(184)
Net Income/(Loss) Attributable to NRG Energy, Inc.	$ 4,438	$ 268	$ (2,153)
Earnings/(Loss) Per Share Attributable to NRG Energy, Inc. Common Stockholders			
Weighted average number of common shares outstanding — basic	262	304	317
Income/(loss) from continuing operations per weighted average common share — basic	$ 15.71	$ 1.51	$ (3.66)
Income/(loss) from discontinued operations per weighted average common share — basic	$ 1.23	$ (0.63)	$ (3.13)
Net Income/(Loss) per Weighted Average Common Share — Basic	$ 16.94	$ 0.88	$ (6.79)
Weighted average number of common shares outstanding — diluted	264	308	317
Income/(loss) from continuing operations per weighted average common share — diluted	$ 15.59	$ 1.49	$ (3.66)
Income/(loss) from discontinued operations per weighted average common share — diluted	$ 1.22	$ (0.62)	$ (3.13)
Net Income/(Loss) per Weighted Average Common Share — Diluted	$ 16.81	$ 0.87	$ (6.79)

See notes to Consolidated Financial Statements

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

	For the Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Net Income/(Loss)	$ 4,441	$ 268	$ (2,337)
Other Comprehensive (Loss)/Income, net of tax			
Unrealized gain on derivatives, net of income tax	—	23	13
Foreign currency translation adjustments, net of income tax	(1)	(11)	12
Available-for-sale securities, net of income tax	(19)	1	(8)
Defined benefit plans, net of income tax	(78)	(35)	46
Other comprehensive (loss)/income	(98)	(22)	63
Comprehensive Income/(Loss)	4,343	246	(2,274)
Less: Comprehensive income/(loss) attributable to noncontrolling interests and redeemable noncontrolling interests	3	14	(179)
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	$ 4,340	$ 232	$ (2,095)

See notes to Consolidated Financial Statements

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In millions)	As of December 31, 2019	2018
ASSETS		
Current Assets		
Cash and cash equivalents	$ 345	$ 563
Funds deposited by counterparties	32	33
Restricted cash	8	17
Accounts receivable, net	1,025	1,024
Inventory	383	412
Derivative instruments	860	764
Cash collateral posted in support of energy risk management activities	190	287
Prepayments and other current assets	245	302
Current assets - held-for-sale	—	1
Current assets - discontinued operations	—	197
Total current assets	3,088	3,600
Property, plant and equipment, net	2,593	3,048
Other Assets		
Equity investments in affiliates	388	412
Operating lease right-of-use assets, net	464	—
Goodwill	579	573
Intangible assets, net	789	591
Nuclear decommissioning trust fund	794	663
Derivative instruments	310	317
Deferred income taxes	3,286	46
Other non-current assets	240	289
Non-current assets - held-for-sale	—	77
Non-current assets - discontinued operations	—	1,012
Total other assets	6,850	3,980
Total Assets	$ 12,531	$ 10,628

See notes to Consolidated Financial Statements

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

(In millions, except share data)	As of December 31, 2019	As of December 31, 2018
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and finance leases	$ 88	$ 72
Current portion of operating lease liabilities	73	—
Accounts payable	722	863
Derivative instruments	781	673
Cash collateral received in support of energy risk management activities	32	33
Accrued expenses and other current liabilities	663	680
Current liabilities - held for sale	—	5
Current liabilities - discontinued operations	—	72
Total current liabilities	2,359	2,398
Other Liabilities		
Long-term debt and finance leases	5,803	6,449
Non-current operating lease liabilities	483	—
Nuclear decommissioning reserve	298	282
Nuclear decommissioning trust liability	487	371
Derivative instruments	322	304
Deferred income taxes	17	65
Other non-current liabilities	1,084	1,274
Non-current liabilities - held-for-sale	—	65
Non-current liabilities - discontinued operations	—	635
Total other liabilities	8,494	9,445
Total Liabilities	10,853	11,843
Redeemable noncontrolling interest in subsidiaries	20	19
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 421,890,790 and 420,288,886 shares issued; and 248,996,189 and 283,650,039 shares outstanding at December 31, 2019 and 2018	4	4
Additional paid-in capital	8,501	8,510
Accumulated deficit	(1,616)	(6,022)
Treasury stock, at cost; 172,894,601 and 136,638,847 shares at December 31, 2019 and 2018	(5,039)	(3,632)
Accumulated other comprehensive loss	(192)	(94)
Total Stockholders' Equity	1,658	(1,234)
Total Liabilities and Stockholders' Equity	$ 12,531	$ 10,628

See notes to Consolidated Financial Statements

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Cash Flows from Operating Activities			
Net income/(loss)	$ 4,441	$ 268	$ (2,337)
Income/(loss) from discontinued operations, net of income tax	321	(192)	(992)
Income/(loss) from continuing operations	4,120	460	(1,345)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities:			
Distributions and equity in earnings of unconsolidated affiliates	14	46	102
Depreciation and amortization	373	421	596
Accretion of asset retirement obligations	51	38	44
Provision for bad debts	95	85	68
Amortization of nuclear fuel	52	48	51
Amortization of financing costs and debt discount/premiums	26	29	29
Loss on debt extinguishment, net	51	44	49
Amortization of emission allowances and out-of-market contracts	38	45	54
Amortization of unearned equity compensation	20	25	35
Net gain on sale of assets and disposal of assets	(23)	(49)	(9)
Impairment losses	113	114	1,614
Changes in derivative instruments	34	37	(170)
Changes in deferred income taxes and liability for uncertain tax benefits	(3,353)	5	13
Changes in collateral deposits in support of risk management activities	105	(105)	(80)
Changes in nuclear decommissioning trust liability	37	60	11
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	5	(83)	(83)
Inventory	22	31	143
Prepayments and other current assets	29	(41)	(187)
Accounts payable	(177)	113	44
Accrued expenses and other current liabilities	(41)	(166)	(88)
Other assets and liabilities	(186)	(104)	(35)
Cash provided by continuing operations	1,405	1,003	856
Cash provided by discontinued operations	8	374	754
Net Cash Provided by Operating Activities	1,413	1,377	1,610
Cash Flows from Investing Activities			
Payments for acquisitions of businesses	(355)	(243)	(14)
Capital expenditures	(228)	(388)	(254)
Net proceeds from sale of emission allowances	11	19	66
Investments in nuclear decommissioning trust fund securities	(416)	(572)	(512)
Proceeds from sales of nuclear decommissioning trust fund securities	381	513	501
Proceeds from sale of assets, net of cash disposed and sale of discontinued operations, net of fees	1,294	1,564	430
Deconsolidations of Agua Caliente and Ivanpah projects	—	(268)	—
Net contributions to investments in unconsolidated affiliates	(91)	(39)	(57)
Net (contributions to)/distributions from discontinued operations	(44)	(60)	150
Other	6	(6)	30
Cash provided by continuing operations	558	520	340
Cash used by discontinued operations	(2)	(725)	(979)
Net Cash Provided/(Used) by Investing Activities	556	(205)	(639)

(In millions)	For the Year Ended December 31, 2019	2018	2017
Cash Flows from Financing Activities			
Payments of dividends to common stockholders	(32)	(37)	(38)
Payments for share repurchase activity	(1,440)	(1,250)	—
Payments for debt extinguishment costs	(26)	(32)	(42)
Net distributions to noncontrolling interest from subsidiaries	(2)	(16)	(30)
Proceeds/(payments) from issuance of common stock	3	21	(2)
Proceeds from issuance of short and long-term debt	1,916	1,100	1,178
Payments of debt issuance costs	(35)	(19)	(18)
Payments for short and long-term debt	(2,571)	(1,734)	(1,884)
Receivable from affiliate	—	(26)	(125)
Other	(4)	(4)	(8)
Cash used by continuing operations	(2,191)	(1,997)	(969)
Cash provided/(used) by discontinued operations	43	471	(169)
Net Cash Used by Financing Activities	(2,148)	(1,526)	(1,138)
Effect of exchange rate changes on cash and cash equivalents	—	1	(1)
Change in Cash from discontinued operations	49	120	(394)
Net (Decrease)/Increase in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash	(228)	(473)	226
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period	613	1,086	860
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period	$ 385	$ 613	$ 1,086

See notes to Consolidated Financial Statements

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In millions)	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Stockholders' Equity
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		25					25
Issuance of common stock		4					4
Common stock dividends[(a)]			(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		6					6
Issuance of common stock		21					21
Common stock dividends[(a)]			(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)
Net income			4,438				4,438
Other comprehensive loss					(98)		(98)
ESPP share purchases		1		2			3
Share repurchases				(1,409)			(1,409)
Equity-based compensation		(16)					(16)
Issuance of common stock		6					6
Common stock dividends[(a)]			(32)				(32)
Balance at December 31, 2019	$ 4	$ 8,501	$ (1,616)	$ (5,039)	$ (192)	$ —	$ 1,658

(a) Dividends per common share were $0.12 for each of the years ended December 31, 2019, 2018 and 2017

See notes to Consolidated Financial Statements

Note 1 — *Nature of Business*

General

NRG Energy, Inc., or NRG or the Company, is an integrated power company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to customers by producing and selling electricity and related products and services in major competitive power markets in the U.S. and Canada in a manner that delivers value to all of NRG's stakeholders. NRG is a customer-driven business focused on perfecting the integrated model by balancing retail load with generation supply within its deregulated markets. The Company sells energy, services, and innovative, sustainable products and services directly to retail customers under the names NRG, Reliant, Green Mountain Energy, Stream and XOOM Energy, as well as other brand names owned by NRG, supported by approximately 23,000 MW of generation as of December 31, 2019.

The Company began managing its integrated model based on the combined results of the retail and wholesale generation businesses with a geographical focus in 2020. As a result, the Company changed its business segments from Retail and Generation to Texas, East and West/Other beginning in the first quarter of 2020. The Company's updated segment structure reflects how management currently makes financial decisions and allocates resources.

The Company's businesses are segregated as follows:

- Texas, which includes all activity related to customer, plant and market operations in Texas;
- East, which includes the remaining activity related to customer operations and all activity related to plant and market operations in the East;
- West/Other, which includes the following assets and activities: (i) all activity related to plant and market operations in the West, (ii) activity related to the Cottonwood power plant that was sold to Cleco on February 4, 2019 and is being leased back until 2025, (iii) the remaining renewables activity, including the Company’s equity method investments in Ivanpah Master Holdings, LLC and Agua Caliente, the remaining Home Solar assets and the NFL stadium solar generating assets, and (iv) activity related to the Company’s equity method investment for the Gladstone power plant in Australia; and
- Corporate activities.

All affected disclosures presented herein have been recast to reflect these changes for all periods presented. For further discussion of segment reporting, refer to Note 19, *Segment Reporting*.

Discontinued Operations

On December 31, 2018, as described in Note 4, *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 was recast in 2018 to reflect the presentation of these entities as discontinued operations.

On August 31, 2018, as described in Note 4, *Acquisitions, Discontinued Operations and Dispositions*, the Company deconsolidated NRG Yield, Inc. and its Renewables Platform for financial reporting purposes. The financial information for all historical periods was recast in 2018 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 deconsolidated the Agua Caliente project from its financial results and began accounting for the project as an equity method investment.

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 the Chapter 11 Cases, of the U.S. Bankruptcy Code. 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 was a discontinued operation and, accordingly, the financial information for all historical periods was recast to reflect GenOn as a discontinued operation. GenOn's plan of reorganization was confirmed on December 14, 2018.

Note 2 — *Summary of Significant Accounting Policies*

Basis of Presentation and Principles of Consolidation

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

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

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,		
(In millions)	**2019**	**2018**	**2017**
Income/(loss) from continuing operations, net of income tax	$ 4,117	$ 465	$ (977)
Income/(loss) from discontinued operations, net of income tax	321	(197)	(1,176)
Net income/(loss) attributable to NRG Energy, Inc. stockholders	$ 4,438	$ 268	$ (2,153)

Discontinued Operations

As described in Note 4, *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 discontinued operations. The financial information for all historical periods was recast in prior years 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.

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,		
(In millions)	**2019**	**2018**	**2017**
Cash and cash equivalents	$ 345	$ 563	$ 770
Funds deposited by counterparties	32	33	37
Restricted cash	8	17	279
Cash and cash equivalents, funds deposited by counterparties and restricted cash shown in the statements of cash flows	$ 385	$ 613	$ 1,086

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 receivables, 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. Accounts receivable balances are written-off against the allowance for doubtful accounts when a receivable is determined to be 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, 2019 and 2018, the allowance for doubtful accounts was $43 million and $32 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 11, *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, 2019, 2018, and 2017, was $3 million, $7 million, and $20 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, 2019 and 2018, the Company had accumulated amortization related to its intangible assets of $1.3 billion and $1.2 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, *Intangibles-Goodwill and Other*, or 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 indicating that it is more-likely-than-not that no impairment occurred, 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 12, *Goodwill and Other Intangibles.*

Income Taxes

The Company accounts for income taxes using the liability method in accordance with ASC 740, *Income Taxes,* or 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 expected to be in effect when the deferred tax is realized.

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 is the amount of benefit that has surpassed the more-likely-than-not threshold, as it 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 20, *Income Taxes*, changes to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, are recorded to income tax (benefit)/expense.

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 or 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 842, *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.

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 842.

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 finance lease. Contingent rental income recognized in the years ended December 31, 2019, 2018, and 2017 was $5 million, $104 million, and $253 million, respectively.

Gross Receipts and Sales Taxes

In connection with its retail sales, 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, 2019, 2018, and 2017, the Company's revenues and cost of operations included gross receipts taxes of $109 million, $99 million, and $92 million, respectively. Additionally, the Company records sales taxes collected from its taxable retail 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, $103 million, $105 million, and $107 million as of December 31, 2019, 2018, and 2017, 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, and other energy related commodities 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. The Company had no cash flow hedges as of December 31, 2019.

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, 2019, 2018, and 2017, amounts recognized as foreign currency transaction gains/(losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2019, 2018, and 2017 were $(13) million, $(13) million and $(2) 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 5, *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 5, *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 14, *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*, or ASC 715. 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 represents third-party interests in the net assets under certain tax equity arrangements, which are consolidated by the Company, that have been entered into to finance the cost of solar energy systems under operating leases. 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 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 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. The investors’ interests in the results of operations of the funding structures are determined as 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, 2019, 2018, and 2017.

	(In millions)
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
Distributions to redeemable noncontrolling interest	(3)
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
Distributions to redeemable noncontrolling interest	(2)
Net income attributable to redeemable noncontrolling interest - continuing operations	3
Balance as of December 31, 2019	**$ 20**

(a) See Note 4, *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 simultaneously leases back the same asset to the Company. If the seller-lessee transfers control of the underlying assets to the buyer-lessor, the arrangement is accounted for under ASC 842-40, Sale-Leaseback Transactions. These arrangements are classified as operating leases on the Company's consolidated balance sheets. See Note 10, *Leases*, for further discussion.

Marketing and Advertising Costs

The Company expenses its marketing and advertising costs as incurred and includes them 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, 2019, 2018, and 2017 were $66 million, $73 million, and $66 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. Reorganization costs for the years ended December 31, 2019, 2018 and 2017 were $23 million, $90 million and $44 million, respectively.

Business Combinations

The Company accounts for its business combinations in accordance with ASC 805, *Business Combinations*, or ASC 805, which 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. The Company also recognizes and measures the goodwill acquired or a gain from a bargain purchase in 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 2019

ASU 2016-02 - In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, or Topic 842, which was further amended through various updates issued by the FASB thereafter, 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 using the modified retrospective approach, as further described in Note 10, *Leases*. The Company recognized operating lease liabilities of $404 million and right of use assets of $321 million upon adoption.

Recent Accounting Developments - Guidance Not Yet Adopted

ASU 2019-12 - In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*, to simplify various aspects related to accounting for income taxes. The guidance in ASU 2019-12 amends the general principles in Topic 740 to eliminate certain exceptions for recognizing deferred taxes for investment, performing intraperiod allocation and calculating income taxes in interim periods. This ASU also includes guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years,. Early adoption is permitted, including adoption in an interim period. The Company is currently in the process of assessing the impact of this guidance on the consolidated financial statements.

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*, or ASU No. 2018-17, in response to stakeholders' observations that Topic 810, *Consolidations*, could be improved thereby improving general purpose financial reporting. Specifically, ASU No. 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 opening retained earnings of the earliest period presented. The Company will adopt the amendments during the first quarter of 2020 and does not expect the adoption to have a material impact on its results of operations, cash flows, or statement of financial position.

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 amendments in ASU No. 2018-13 eliminate such disclosures as the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy and 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. Certain disclosures in ASU No. 2018-13 are required to be applied on a retrospective basis and others on a prospective basis. The Company will adopt the amendments during the first quarter of 2020. As the amendments contemplates changes in disclosures only, it will have no impact on the Company's results of operations, cash flows, or statement of financial position.

ASU 2016-13 - In June 2016, the FASB issues ASU No. 2016-13, *Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*, or ASU No. 2016-13, which was further amended through various updates issued by the FASB thereafter. The guidance in ASU No. 2016-13 provides a new model for recognizing credit losses on financial assets carried at amortized cost using an estimate of expected credit losses, instead of the "incurred loss" methodology previously required for recognizing credit losses that delayed recognition until it was probable that a loss was incurred. The estimate of expected credit losses is to be based on consideration of past events, current conditions and reasonable and supportable forecasts of future conditions. ASU No. 2016-13 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. The guidance is required to be adopted using a modified retrospective approach through a cumulative-effect adjustment to opening retained earnings as of the effective date and requires additional disclosures. The Company will adopt the guidance during the first quarter of 2020 and does not expect the adoption to have a material impact on its results of operations, cash flows, or statement of financial position.

Note 3 — *Revenue Recognition*

Revenue from Contracts with Customers

On January 1, 2018, the Company adopted the guidance in ASC 606, *Revenue from Contracts*, or ASC 606, with customers 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 $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 2017 comparative information was not restated and continues to be reported under the accounting standards in effect for that period. The Company's policies with respect to its various revenue streams are detailed below. The Company generally 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 Revenue

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 obligations 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 consist of revenues billed to a third party at either market or negotiated contract terms 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 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 used to hedge the sale of electricity 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 market or negotiated contract terms 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 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.

Performance Obligations

As of December 31, 2019, estimated future fixed fee performance obligations are $564 million, $604 million, $303 million, $42 million, and $8 million for fiscal years 2020, 2021, 2022, 2023, and 2024, respectively. These performance obligations are for cleared auction MWs in the PJM, ISO-NE, NYISO and MISO capacity auctions and are subject to penalties for non performance.

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 Revenue

The following tables represent the Company's disaggregation of revenue from contracts with customers for the years ended December 31, 2019 and 2018:

	For the Year Ended December 31, 2019				
(In millions)	**Texas**	**East**	**West/Other**	**Corporate/Eliminations**	**Total**
Retail revenue					
Mass Market	$ 5,027	$ 1,230	$ —	$ (3)	$ 6,254
Business Solutions	1,205	74	—	—	1,279
Total retail revenue	6,232	1,304	—	(3)	7,533
Energy revenue[a]	529	322	318	—	1,169
Capacity revenue[a]	—	664	36	—	700
Mark-to-market for economic hedging activities[b]	47	(29)	16	(1)	33
Other revenue[a]	261	58	70	(3)	386
Total operating revenue	7,069	2,319	440	(7)	9,821
Less: Lease revenue	—	1	19	—	20
Less: Realized and unrealized ASC 815 revenue	1,562	183	67	(2)	1,810
Total revenue from contracts with customers	$ 5,507	$ 2,135	$ 354	$ (5)	$ 7,991

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

(In millions)	**Texas**	**East**	**West/Other**	**Corporate/Eliminations**	**Total**
Energy revenue	$ 1,459	$ 98	$ 39	$ (1)	$ 1,595
Capacity revenue	—	109	—	—	109
Other revenue	56	5	12	—	73

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

	For the Year Ended December 31, 2018				
(In millions)	**Texas**	**East**	**West/Other**	**Corporate/Eliminations**	**Total**
Retail revenue					
Mass Market	$ 4,618	$ 974	$ —	$ (1)	$ 5,591
Business Solutions	1,238	65	—	—	1,303
Total retail revenue	5,856	1,039	—	(1)	6,894
Energy revenue[a]	371	546	566	13	1,496
Capacity revenue[a]	—	746	79	—	825
Mark-to-market for economic hedging activities[b]	(77)	(35)	(5)	(13)	(130)
Other revenue[a][c]	251	75	84	(17)	393
Total operating revenue	6,401	2,371	724	(18)	9,478
Less: Lease revenue	1	1	19	—	21
Less: Realized and unrealized ASC 815 revenue	1,096	210	2	1	1,309
Total revenue from contracts with customers	$ 5,304	$ 2,160	$ 703	$ (19)	8,148

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

(In millions)	**Texas**	**East**	**West/Other**	**Corporate/Eliminations**	**Total**
Energy revenue	$ 1,131	$ 90	$ (2)	$ 14	$ 1,233
Capacity revenue	—	137	—	—	137
Other revenue	42	17	9	1	69

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

Contract Balances

The following table reflects the contract assets and liabilities included in the Company's balance sheet as of December 31, 2019 and 2018:

(In millions)	December 31, 2019	December 31, 2018
Deferred customer acquisition costs	$ 133	$ 111
Accounts receivable, net - Contracts with customers	1,002	999
Accounts receivable, net - Derivative instruments	18	20
Accounts receivable, net - Affiliate	5	5
Total accounts receivable, net	$ 1,025	$ 1,024
Unbilled revenues (included within Accounts receivable, net - Contracts with customers)	$ 402	$ 392
Deferred revenues [(a)]	$ 82	$ 67

(a) Deferred revenues from contracts with customers for the years ended December 31, 2019 and 2018 were approximately $24 million and $19 million, respectively.

The revenue recognized from contracts with customers during years ended December 31, 2019 and 2018 relating to the deferred revenue balance at the beginning of each period was $13 million and $16 million, respectively. The change in deferred revenue balances during the years ended December 31, 2019 and 2018 was primarily due to the timing difference of when consideration was received and when the performance obligation was transferred.

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.

Note 4 — *Acquisitions, Discontinued Operations and Dispositions*

Acquisitions

Stream Energy Acquisition — On August 1, 2019, the Company completed the acquisition of Stream Energy's retail electricity and natural gas business operating in 9 states and Washington, D.C. for $329 million, including working capital and other adjustments of approximately $29 million. The acquisition increased NRG's retail portfolio by approximately 600,000 RCEs or 450,000 customers and supports NRG's ongoing efforts to increase the Company's retail position in Texas and the Northeast. The purchase price was allocated as follows:

	(In millions)
Account receivable	$ 98
Accounts payable	(73)
Other net current and non-current working capital	5
Marketing partnership	154
Customer relationships	85
Trade name	28
Other intangible assets	26
Goodwill [(a)]	6
Stream Purchase Price	$ 329

(a) Goodwill arising from the acquisition is attributed to the value of the platform acquired and the synergies expected from combining the operations of Stream Energy with NRG's existing businesses. Goodwill of $5 million and $1 million was assigned to the Texas and East segments, respectively, and is not deductible for tax purposes

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, including working capital and other adjustments of $48 million. The acquisition increased NRG's retail portfolio by approximately 395,000 RCEs or 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

(a) Goodwill arising from the acquisition is attributed to the value of the platform acquired and the synergies expected from combining the operations of XOOM Energy with NRG's existing businesses. Goodwill of $28 million and $6 million was assigned to the Texas and East segments, respectively, and is deductible for tax purposes

Small Book Acquisitions — During 2019, the Company acquired several books of customers totaling approximately 72,000 customers for $17 million, of which $13 million was paid in 2019. During 2018, the Company acquired several books of customers totaling approximately 115,000 customers, along with brand names, for $44 million, of which $40 million was paid in 2018, $2 million was paid in 2019 and $2 million was prepaid in 2017. The majority of the purchase price for the 2019 and 2018 book acquisitions were 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 for cash consideration of $1 billion excluding working capital and other adjustments. 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 were reclassified as discontinued operations at December 31, 2018. 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 1,153 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 did not use held-for-sale or discontinued operations treatment in accounting for the Cottonwood facility.

Summarized results of South Central discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Operating revenues	$ 31	$ 410	$ 422
Operating costs and expenses	(23)	(346)	(335)
Other income	—	2	—
Gain from operations of discontinued components	**8**	**66**	**87**
Gain on disposal of discontinued operations, net of tax	20	—	—
Gain from discontinued operations, including disposal, net of tax	**$ 28**	**$ 66**	**$ 87**

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

(In millions)	December 31, 2018
Cash and cash equivalents	$ 89
Accounts receivable, net	49
Inventory	35
Other current assets	5
Current assets - discontinued operations	178
Property, plant and equipment, net	408
Other non-current assets	1
Non-current assets - discontinued operations	409
Accounts payable	19
Other current liabilities	5
Current liabilities - discontinued operations	24
Out-of-market contracts, net	50
Other non-current liabilities	11
Non-current liabilities - discontinued operations	$ 61

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 were 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 in 2018. During the year ended December 31, 2019, the Company recorded an adjustment to reduce the purchase price by $15 million in connection with the completion of the Patriot Wind project. The Company expects to recover a portion of this adjustment in the future. During the year ended December 31, 2019, the Company reduced the liability related to the indemnification of NRG Yield for any increase in property taxes for certain solar properties by $22 million due to updated estimates.

Carlsbad

On February 6, 2018, NRG entered into an agreement with NRG Yield and GIP to sell 100% of its membership interests in Carlsbad Energy Holdings LLC, which owns the Carlsbad project, for $385 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. At the time of the sale of NRG Yield and the Renewables Platform in August 2018, the Company concluded that the Carlsbad project met the criteria for discontinued operations and accordingly, all current and prior period results for Carlsbad were reclassified as discontinued operations. The transaction closed on February 27, 2019. Carlsbad will continue to have a ground lease and easement agreement with NRG with an initial term ending in 2039 and two ten-year extensions. As a result of the transaction, additional commitments related to the project totaled $23 million as of December 31, 2019 and December 31, 2018.

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

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Operating revenues	$ 19	$ 909	$ 1,164
Operating costs and expenses	(9)	(661)	(1,114)
Other expenses	(5)	(174)	(288)
Gain/(loss) from operations of discontinued components, before tax	5	74	(238)
Income tax expense	—	4	52
Gain/(loss) from discontinued operations, net of tax	**5**	**70**	**(290)**
Gain/(loss) on disposal of discontinued operations, net of tax	265	(134)	—
Income/(expense) from California property tax indemnification	22	(153)	—
Income/(expense) from other commitments, indemnification and fees	4	(75)	—
Income/(loss) on disposal of discontinued operations, net of tax	**291**	**(362)**	**—**
Income/(loss) from discontinued operations, net of tax	**$ 296**	**$ (292)**	**$ (290)**

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

(In millions)	**December 31, 2018 [(a)]**
Restricted Cash	$ 4
Accounts receivable, net	10
Other current assets	5
Current assets - discontinued operations	19
Property, plant and equipment, net	590
Intangible assets, net	9
Other non-current assets	4
Non-current assets - discontinued operations	603
Current portion of long term debt and capital leases	20
Accounts payable	27
Other current liabilities	1
Current liabilities - discontinued operations	48
Long-term debt and capital leases	572
Other non-current liabilities	2
Non-current liabilities - discontinued operations	$ 574

(a) Represents 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 $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 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 $328 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 were reclassified in 2017 as discontinued operations.

Summarized results of discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Operating revenues	$ —	$ —	$ 646
Operating costs and expenses	—	—	(702)
Other expenses	—	—	(98)
Loss from operations of discontinued components, before tax	—	—	(154)
Income tax expense	—	—	9
Loss from discontinued operations	**—**	**—**	**(163)**
Interest income - affiliate	—	3	8
Income/(loss) from discontinued operations, net of tax	**—**	**3**	**(155)**
Pre-tax loss on deconsolidation	—	—	(208)
Settlement consideration, insurance and services credit	—	63	(289)
Pension and post-retirement liability assumption	—	21	(131)
Other	(3)	(53)	(6)
(Loss)/income on disposal of discontinued operations, net of tax	**(3)**	**31**	**(634)**
(Loss)/income from discontinued operations, net of tax	**$ (3)**	**$ 34**	**$ (789)**

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. As a result of GenOn's emergence from bankruptcy, NRG took 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; such letters of credit were never drawn and were returned and canceled on December 17, 2019 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.

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. The Company entered into a project management agreement in 2018 to manage construction of Canal 3 and substantial completion was reached in June 2019.

The Company completed other asset sales for cash proceeds of $22 million and $28 million during the years ended December 31, 2019 and 2018, respectively.

Note 5 — *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,			
	2019		2018	
(In millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Assets				
Notes receivable	$ 11	$ 8	$ 17	$ 14
Liabilities				
Long-term debt, including current portion [(a)]	$ 5,956	$ 6,504	$ 6,591	$ 6,697

(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, 2019 and 2018:

	As of December 31, 2019		As of December 31, 2018	
(In millions)	**Level 2**	**Level 3**	**Level 2**	**Level 3**
Long-term debt, including current portion	$ 6,388	$ 116	$ 6,528	$ 169

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, 2019			
	Fair Value			
(In millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Investments in securities (classified within other current and non-current assets)	$ 20	$ —	$ 20	$ —
Nuclear trust fund investments:				
Cash and cash equivalents	17	17	—	—
U.S. government and federal agency obligations	68	68	—	—
Federal agency mortgage-backed securities	100	—	100	—
Commercial mortgage-backed securities	29	—	29	—
Corporate debt securities	109	—	109	—
Equity securities	388	388	—	—
Foreign government fixed income securities	5	—	5	—
Other trust fund investments:				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Commodity contracts	1,170	84	893	193
Measured using net asset value practical expedient:				
Equity securities-nuclear trust fund investments	78	—	—	—
Equity securities	8	—	—	—
Total assets	$ 1,993	$ 558	$ 1,156	$ 193
Derivative liabilities:				
Commodity contracts	$ 1,103	$ 143	$ 805	$ 155
Total liabilities	$ 1,103	$ 143	$ 805	$ 155

	As of December 31, 2018			
	Fair Value			
(In millions)	Total	Level 1	Level 2	Level 3
Investments in securities (classified within other current or 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

The following tables reconcile, for the years ended December 31, 2019 and 2018, 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, 2019		
	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)		
(In millions)	**Debt Securities**	**Derivatives [a]**	**Total**
Beginning balance as of January 1, 2019	$ 19	$ 20	$ 39
Contracts added from acquisitions	—	(3)	(3)
Total gains/(losses) — realized/unrealized:			
Included in earnings	—	(26)	(26)
Included in OCI	—	—	—
Purchases	—	40	40
Sale	(19)	—	(19)
Transfers into Level 3 [b]	—	2	2
Transfers out of Level 3 [b]	—	5	5
Ending balance as of December 31, 2019	$ —	$ 38	$ 38
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, 2019	$ —	$ 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, 2018		
	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)		
(In millions)	**Debt Securities**	**Derivatives [a]**	**Total**
Beginning balance as of January 1, 2018	$ 19	$ (15)	$ 4
Contracts acquired in XOOM acquisition	—	12	$ 12
Total gains realized/unrealized included in earnings	—	(21)	(21)
Purchases	—	41	41
Transfers into Level 3 [b]	—	5	5
Transfer 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

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 measured using net asset value practical expedient. See also Note 7, *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 16% of derivative assets and 14% 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, 2019 and December 31, 2018 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, 2019, 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, 2019 and 2018:

	Significant Unobservable Inputs						
	December 31, 2019						
	Fair Value				Input/Range		
(In millions)	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
Power Contracts	$ 151	$ 139	Discounted Cash Flow	Forward Market Price (per MWh)	$ 8	$ 218	$ 24
FTRs	42	16	Discounted Cash Flow	Auction Prices (per MWh)	(105)	213	0
	$ 193	$ 155					

	Significant Unobservable Inputs						
	December 31, 2018						
	Fair Value				Input/Range		
(In millions)	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
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	0
	$ 109	$ 89					

The following table provides sensitivity of fair value measurements to increases/(decreases) in significant unobservable inputs as of December 31, 2019 and 2018:

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, 2019, the Company recorded $190 million of cash collateral posted and $32 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, 2019, counterparty credit exposure, excluding credit exposure from RTOs, ISOs, and registered commodity exchanges and certain long-term agreements, was $239 million and NRG held collateral (cash and letters of credit) against those positions of $51 million, resulting in a net exposure of $233 million. NRG periodically receives collateral from counterparties in excess of their exposure. Collateral amounts shown include such excess while net exposure shown excludes excess collateral received. Approximately 67% of the Company's exposure before collateral is expected to roll off by the end of 2021. 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	84 %
Financial institutions	16
Total	100 %

Category	Net Exposure [(a) (b)] (% of Total)
Investment grade	56 %
Non-Investment grade/Non-Rated	44
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 $33 million exposure to one wholesale counterparty in excess of 10% of the total net exposure discussed above as of December 31, 2019. 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, primarily 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, 2019, aggregate credit risk exposure managed by NRG to these counterparties was approximately $548 million for the next five years, including exposure to PG&E through its unconsolidated affiliates, Ivanpah and Agua Caliente.

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, 2019, 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 $95 million, $85 million, and $68 million for the years ending December 31, 2019, 2018, and 2017, 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 6 — *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, 2019, 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 2020; and
- Other energy derivatives instruments extending through 2029.

Also, as of December 31, 2019, 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 2036;
- 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 was 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 entered into interest rate swap agreements. As of December 31, 2019, NRG had no interest rate derivative instruments as a result of the early termination of such contracts in connection with the repayment of the 2023 Term Loan Facility during the second quarter of 2019. See Note 13, *Debt and Finance Leases*, for further discussion.

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, 2019 and 2018. 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.

(In millions)		Total Volume	
Commodity	**Units**	**December 31, 2019**	**December 31, 2018**
Emissions	Short Ton	3	(2)
Renewables Energy Certificates	Certificates	1	1
Coal	Short Ton	10	13
Natural Gas	MMBtu	(181)	(330)
Oil	Barrels	—	1
Power	MWh	38	1
Capacity	MW/Day	(1)	(1)
Interest	Dollars	$ —	$ 1,000

The decrease in the natural gas position was primarily the result of additional retail hedge positions and settlement of generation hedges. The increase in the power position was primarily the result of additional retail hedge positions and the settlement of generation hedges. The decrease in the interest position was the result of the early settlement of the interest rate swaps.

Fair Value of Derivative Instruments

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

	Fair Value			
	Derivative Assets		Derivative Liabilities	
(In millions)	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$ —	$ 17	$ —	$ —
Interest rate contracts long-term	—	22	—	—
Commodity contracts current	860	747	781	673
Commodity contracts long-term	310	295	322	304
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	$ 1,170	$ 1,081	$ 1,103	$ 977

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		
(In millions)	Gross Amounts of Recognized Assets/Liabilities	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
As of December 31, 2019				
Commodity contracts:				
Derivative assets	$ 1,170	$ (909)	$ (7)	$ 254
Derivative liabilities	(1,103)	909	73	(121)
Total commodity contracts	$ 67	$ —	$ 66	$ 133

		Gross Amounts Not Offset in the Statement of Financial Position		
(In millions)	Gross Amounts of Recognized Assets/Liabilities	Derivative Instruments	Cash Collateral (Held)/Posted	Net Amount
As of December 31, 2018				
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

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, for the years 2018 and 2017. As of December 31, 2019, NRG had no interest rate derivative instruments as a result of the early termination of such contracts in connection with the repayment of the 2023 Term Loan Facility, as further discussed in Note 13, *Debt and Finance Leases.*

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

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

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,		
(In millions)	**2019**	**2018**	**2017**
Unrealized mark-to-market results			
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (68)	$ (73)	$ 47
Reversal of acquired loss/(gain) positions related to economic hedges	6	(10)	—
Net unrealized gains on open positions related to economic hedges	42	97	159
Total unrealized mark-to-market (losses)/gains for economic hedging activities	(20)	14	206
Reversal of previously recognized unrealized (gains) on settled positions related to trading activity	(11)	(12)	(25)
Net unrealized gains on open positions related to trading activity	31	29	14
Total unrealized mark-to-market gains/(losses) for trading activity	20	17	(11)
Total unrealized gains	$ —	$ 31	$ 195

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Unrealized gains/(losses) included in operating revenues	$ 53	$ (113)	$ 241
Unrealized (losses)/gains included in cost of operations	(53)	144	(46)
Total impact to statement of operations — energy commodities	$ —	$ 31	$ 195
Total impact to statement of operations — interest rate contracts	$ (38)	$ —	$ 4

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, 2019, 2018 and 2017 the $42 million, $97 million, and $159 million gains from economic hedge positions were primarily the result of an increase in the value of forward purchases of ERCOT heat rate contracts due to ERCOT heat rate expansion.

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, 2019 was $14 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of December 31, 2019 was $24 million. The Company is also a party to certain marginable agreements under which it has a net liability position, but the counterparty has not called for the collateral due, which was approximately $3 million as of December 31, 2019.

See Note 5, *Fair Value of Financial Instruments*, for discussion regarding concentration of credit risk.

Note 7 — *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, 2019				As of December 31, 2018			
(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	$ 17	$ —	$ —	—	$ 19	$ —	$ —	—
U.S. government and federal agency obligations	68	4	—	11	46	1	—	12
Federal agency mortgage-backed securities	100	3	—	24	100	1	2	23
Commercial mortgage-backed securities	29	1	1	24	22	—	1	22
Corporate debt securities	109	6	—	11	96	1	2	11
Equity securities	466	324	—	—	376	231	1	—
Foreign government fixed income securities	5	—	—	10	4	—	—	9
Total	$ 794	$ 338	$ 1		$ 663	$ 234	$ 6	

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,		
(In millions)	**2019**	**2018**	**2017**
Realized gains	$ 18	$ 17	$ 22
Realized (losses)	(9)	(13)	(8)
Proceeds from sale of securities	381	513	501

Note 8 — *Inventory*

Inventory consisted of:

	As of December 31,	
(In millions)	**2019**	**2018**
Fuel oil	$ 73	$ 74
Coal	93	97
Natural gas	21	28
Spare parts	196	213
Total Inventory	$ 383	$ 412

Note 9 — *Property, Plant and Equipment*

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

	As of December 31,		Depreciable
(In millions)	**2019**	**2018**	**Lives**
Facilities and equipment	$ 3,262	$ 3,763	1-40 years
Land and improvements	324	347	
Nuclear fuel	235	212	5 years
Hardware and office equipment and furnishings	422	431	2-10 years
Construction in progress	102	106	
Total property, plant, and equipment	4,345	4,859	
Accumulated depreciation	(1,752)	(1,811)	
Net property, plant, and equipment	$ 2,593	$ 3,048	

The Company recorded long-lived asset impairments during the years ended December 31, 2019 and 2018, as further described in Note 11, *Asset Impairments.*

Note 10 — *Leases*

2019 Leases

The Company leases generating facilities, land, office and equipment, railcars, and storefront space at retail stores. Operating leases with an initial term greater than twelve months are recognized as right-of-use assets and lease liabilities in the consolidated balance sheets. The Company recognizes lease expense for all operating leases on a straight-line basis over the lease term. In the future, should another systematic basis become more representative of the pattern in which the lessee expects to consume the remaining economic benefit of the right-of-use asset, the Company will use that basis for lease expense.

The Company considers a contract to be or to contain a lease when both of the following conditions apply: 1) an asset is either explicitly or implicitly identified in the contract and 2) the contract conveys to the Company the right to control the use of the identified asset for a period of time. The Company has the right to control the use of the identified asset when the Company has both the right to obtain substantially all the economic benefits from the use of the identified asset and the right to direct how and for what purpose the identified asset is used throughout the period of use.

Lease payments are typically fixed and payable on a monthly, quarterly, semi-annual or annual basis. Lease payments under certain agreements may escalate over the lease term either by a fixed percentage or a fixed dollar amount. Certain leases may provide for variable lease payments in the form of payments based on usage, a percentage of sales from the location under lease, or index-based (e.g., the U.S. Consumer Price Index) adjustments to lease payments. The Company has no leases which contain residual value guarantees provided by the Company as a lessee.

The Company's leases may grant the Company an option to renew a lease for an additional term(s) or to terminate the lease after a certain period. As part of its transition from the guidance contained in ASC 840 to the updated guidance in ASC 842, the Company elected not to use the practical expedient of using hindsight to determine the lease term and in assessing impairment of the right-of-use assets.

As permitted by ASC 842, the Company made an accounting policy election for all asset classes not to recognize right-of-use assets and lease liabilities in the consolidated balance sheets for its short-term leases, which are leases that have a lease term of twelve months or less. For the initial measurement of lease liabilities, the Company uses as the discount rate either the rate implicit in the lease, if known, or its incremental borrowing rate, which is the rate of interest that the Company would have to pay to borrow, on a collateralized basis, over a similar term an amount equal to the payments for the lease.

In transition to ASC 842, the Company elected to apply the effective date transition method as of the January 1, 2019 adoption date. In accordance with this method, the Company's reporting for comparative periods prior to January 1, 2019 presented in the financial statements continues to be in conformity with the guidance in ASC 840. The Company elected the following practical expedients, which allow entities to:

- Not reassess whether any contracts that existed prior to the January 1, 2019 implementation date are or contain leases;
- Not reassess the lease classification for any leases that commenced prior to the January 1, 2019 implementation date, meaning that all commenced capital leases under ASC 840 will be classified as finance leases under ASC 842 and all commenced operating leases under ASC 840 will be classified as operating leases under ASC 842;
- Not reassess initial direct costs for any leases;
- Not reassess whether existing land easements, which were not previously accounted as leases under ASC 840, are or contain leases; and
- Not separate lease and non-lease components for all asset classes, except office space leases and generation facilities leases.

As described in Note 4, *Acquisitions, Discontinued Operations and Dispositions*, upon the close of the South Central Portfolio sale, the Company entered into an agreement to leaseback the Cottonwood facility through May 2025. The lease was accounted for in accordance with ASC 842-40, *Sale and Leaseback Transactions*, as an operating lease and accordingly, a right-of-use asset and lease liability were established on the lease commencement date and will be amortized through the end of the lease.

Lease Cost:

(In millions)	**For the Year Ended December 31, 2019**
Finance lease cost:	$ —
Amortization of right-of-use assets	—
Shares issued under ESPP	—
Interest on lease liabilities	—
Operating lease cost	$ 109
Short-term lease cost	3
Variable lease cost	6
Sublease income	(17)
Total lease cost	$ 101

Other information:

(In millions)	**For the Year Ended December 31, 2019**
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 104
Right-of-use assets obtained in exchange for new operating lease liabilities	215

Lease Term and Discount Rate for operating leases:

	December 31, 2019
Weighted average remaining lease term (in years)	7.8
Weighted average discount rate	5.72 %

As of December 31, 2019, annual payments based on the maturities of NRG's leases are expected to be as follows:

	(In millions)
2020	$ 96
2021	87
2022	87
2023	85
2024	75
Thereafter	296
Total undiscounted lease payments	$ 726
Less: present value adjustment	(170)
Total discounted lease payments	$ 556

2018 Operating Lease Commitments

The below describes the Company's operating lease commitments as reported in the Company's Annual Report on Form 10-K for the year ended December 31, 2018, under Note 21, *Commitments and Contingencies*, prior to the adoption of ASC 842.

The Company leases 100% interests in the Powerton facility and Unit 7 and Unit 8 of the Joliet facility through 2034 and 2030, respectively, through its indirect subsidiary, Midwest Generation, LLC. The Company accounted for these leases as operating leases and recorded lease expense on a straight-line basis over the lease term. In connection with the acquisition of Midwest Generation, the Company recorded the out-of-market value as a liability of $159 million in 2014. The liability was being amortized through rent expense on a straight-line basis over the term of the lease. The Company recorded lease expense, net of amortization of the out-of-market liability, of approximately $14 million per year. The accounting for these out-of-market contracts changed effective January 1, 2019, upon the adoption of ASC 842.

Future minimum lease commitments under the Powerton and Joliet operating leases as of December 31, 2018 were as follows:

Period	(In millions)
2019	$ 1
2020	1
2021	3
2022	6
2023	6
Thereafter	222
Total [(a)]	$ 239

[(a)] Termination of leases could be at a significant premium to the remaining lease payments

Other Operating Leases

NRG leases certain Company facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2036. Lease expense under operating leases, other than Powerton and Joliet, was $66 million and $69 million for the years ended December 31, 2018 and 2017, respectively.

Future minimum lease commitments under operating leases, other than Powerton and Joliet, as of December 31, 2018 were as follows:

Period[(a)]	(In millions)
2019	$ 60
2020	55
2021	43
2022	40
2023	39
Thereafter	95
Total	$ 332

(a) Amounts in the table exclude future sublease income of $29 million associated with long-term leases for office locations

Note 11 — *Asset Impairments*

2019 Impairment Losses

Petra Nova Parish Holdings — During the third quarter of 2019, NRG contributed $95 million in cash to Petra Nova and posted a $12 million letter of credit to cover certain project debt reserve requirements. The cash portion of the contribution was used by Petra Nova to prepay a significant portion of the project debt. As a result, the previously disclosed guarantee of up to $124 million related to the project level debt provided by NRG was canceled and the remaining project debt became non-recourse to NRG. In relation to this contribution, the Company evaluated the project for impairment and determined that the carrying amount of the Company's equity method investment exceeded the fair value of the investment and that the decline is considered to be other-than-temporary. In determining the fair value, the Company utilized an income approach and considered project specific assumptions for the estimated future project cash flows. 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 $101 million.

Other Impairments — For the year ended December 31, 2019, the Company recorded $12 million of impairment losses primarily related to investments and intangibles.

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 $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. 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 of 2017, 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.

Note 12 — *Goodwill and Other Intangibles*

Goodwill

NRG's goodwill balance was $579 million and $573 million as of December 31, 2019 and 2018, respectively. The increase in goodwill is due to the acquisition of Stream Energy. As of December 31, 2019, goodwill consisted of $165 million associated with the acquisition of Midwest Generation and $414 million for retail business acquisitions, including Texas non-commodity, XOOM and Stream Energy.

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, 2018, 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, 2018.

Intangible Assets

The Company's intangible assets as of December 31, 2019, primarily reflect intangible assets established with the acquisitions of various companies, including Stream Energy, XOOM, other retail acquisitions, and Texas Genco. Intangible assets are comprised of the following:

- *Emission Allowances* — These intangibles primarily consist of SO_2 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 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. During the year ended December 31, 2019, there were no impairment losses related to SO_2 emissions allowances.
- *In-market nuclear fuel contracts* — These intangibles were established with the Texas Genco acquisition in 2006 and are amortized to cost of operations over expected volumes over the life of each contract.
- *Customer 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 marketing vendors and loyalty and affinity partners for customer acquisition. 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.
- *Other* — Consists of renewable energy credits, costs to extend the operating license for STP Units 1 and 2, and energy supply contracts acquired with Stream Energy that represent the fair value at the acquisition date of in-market contracts for the purchase of energy to serve retail electric customers. Renewable energy credits are amortized to cost of operations as they are retired for usage. Energy supply contracts are amortized to depreciation and amortization based on the expected delivery under the respective contracts.

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

(In millions)

Year Ended December 31, 2019	Emission Allowances	Fuel Contracts	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
January 1, 2019	$ 659	$ 49	$ 478	$ 131	$ 345	$ 80	$ 1,742
Purchases	13	—	—	—	—	29	42
Acquisition of businesses [(a)]	—	—	110	154	28	26	318
Usage	(4)	—	—	—	—	(17)	(21)
Write-off of fully amortized balances	(8)	—	(13)	—	—	(9)	(30)
Impairment	—	—	(2)	—	—	—	(2)
Other	2	—	—	—	—	—	2
December 31, 2019	662	49	573	285	373	109	2,051
Less accumulated amortization	(539)	(45)	(345)	(75)	(220)	(38)	(1,262)
Net carrying amount	$ 123	$ 4	$ 228	$ 210	$ 153	$ 71	$ 789

(a) The weighted average life of acquired intangibles was: customer relationships 7 years, marketing partnerships 9 years, trade names 12 years, and energy supply contracts 2 years

(In millions)

Year Ended December 31, 2018	Emission Allowances	Fuel Contracts	Customer Relationships	Marketing Partnerships	Trade Names	Other	Total
January 1, 2018	$ 755	$ 49	$ 768	$ 88	$ 342	$ 78	$ 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	478	131	345	80	1,742
Less accumulated amortization	(515)	(45)	(314)	(61)	(195)	(21)	(1,151)
Net carrying amount	$ 144	$ 4	$ 164	$ 70	$ 150	$ 59	$ 591

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

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

	Years Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Emission allowances	$ 32	$ 39	$ 71
Customer relationships	44	32	34
Marketing partnerships	15	9	5
Trade names	25	23	23
Other	35	30	33
Total amortization	$ 151	$ 133	$ 166

The following table presents estimated amortization of NRG's intangible assets as of December 31, 2019 for each of the next five years:

(In millions)

Year Ended December 31,	**Emission Allowances**	**Fuel Contracts**	**Customer Relationships**	**Marketing Partnerships**	**Trade Names**	**Other**	**Total**
2020	$ 36	$ 1	$ 68	$ 24	$ 27	$ 33	$ 189
2021	35	—	52	24	27	3	141
2022	38	—	36	23	27	3	127
2023	40	1	35	23	26	3	128
2024	35	—	15	23	17	3	93

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, 2019 and 2018, the value of emission allowances held-for-sale was $6 million and $12 million, respectively, 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 were classified as non-current liabilities on NRG's consolidated balance sheet. These included out-of-market lease contracts acquired with Midwest Generation of $121 million as of December 31, 2018. As a result of the Company's adoption of ASC 842 on January 1, 2019, out-of-market lease contracts are now included as a component of operating lease right-of-use assets. Prior to January 1, 2019, these out-of-market contracts were amortized to cost of operations.

Note 13 — *Debt and Finance Leases*

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

(In millions, except rates)	December 31, 2019	December 31, 2018	December 31, 2019 Interest rate %
Recourse debt:			
Senior Notes, due 2024	$ —	$ 733	6.250
Senior Notes, due 2026	1,000	1,000	7.250
Senior Notes, due 2027	1,230	1,230	6.625
Senior Notes, due 2028	821	821	5.750
Senior Notes, due 2029	733	—	5.250
Convertible Senior Notes, due 2048[a]	575	575	2.750
Senior Secured First Lien Notes, due 2024	600	—	3.750
Senior Secured First Lien Notes, due 2029	500	—	4.450
2023 Term Loan Facility [b]	—	1,698	L+ 1.75
Revolving Credit Facility [c]	83	—	L+ 1.75
Tax-exempt bonds	466	466	4.125 - 6.00
Subtotal recourse debt	6,008	6,523	
Non-recourse debt:			
Agua Caliente Borrower 1, due 2038	—	86	5.430
Midwest Generation, due 2019	—	48	4.390
Other	34	34	various
Subtotal all non-recourse debt	34	168	
Subtotal long-term debt (including current maturities)	6,042	6,691	
Finance leases	—	1	various
Subtotal long-term debt and finance leases (including current maturities)	6,042	6,692	
Less current maturities	(88)	(72)	
Less debt issuance costs	(65)	(70)	
Discounts	(86)	(101)	
Total long-term debt and finance leases	$ 5,803	$ 6,449	

(a) The effective interest rate was 5.05% and 5.02% for the years ended December 31, 2019 and 2018, respectively
(b) As of December 31, 2018, the interest rate was 1-month LIBOR plus 1.75%
(c) As of December 31, 2019, the interest rate was 1-week LIBOR plus 1.75%

Debt includes the following discounts:

(In millions)	As of December 31, 2019	As of December 31, 2018
Term loan facility, due 2023	$ —	$ (4)
Midwest Generation, due 2019	—	(1)
Senior Secured First Lien Notes, due 2024 and 2029	(1)	—
Convertible Senior Notes, due 2048	(85)	(96)
Total discounts	$ (86)	$ (101)

Consolidated Annual Maturities

As of December 31, 2019, annual payments based on the maturities of NRG's debt are expected to be as follows:

	(In millions)
2020[a]	$ 88
2021	6
2022	5
2023	4
2024	604
Thereafter	5,335
Total	$ 6,042

(a) Includes $83 million of Revolving Credit Facility balance outstanding as of December 31, 2019

Recourse Debt

Senior Notes

Issuance of 2029 Senior Notes

On May 14, 2019, NRG issued $733 million of aggregate principal amount at par of 5.25% senior unsecured notes due 2029, or the 2029 Senior Notes. The 2029 Senior Notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest will be paid semi-annually beginning on December 15, 2019, until the maturity date of June 15, 2029. The proceeds from the issuance of the 2029 Senior Notes were utilized to redeem the Company's remaining 6.25% Senior Notes due 2024.

Issuance of 2024 and 2029 Senior Secured First Lien Notes

On May 28, 2019, NRG issued $1.1 billion of aggregate principal amount of senior secured first lien notes, consisting of $600 million 3.75% senior secured first lien notes due 2024 and $500 million 4.45% senior secured first lien notes due 2029, or the Senior Secured First Lien Notes, at a discount. The Senior Secured First Lien Notes are guaranteed on a first-priority basis by each of NRG's current and future subsidiaries that guarantee indebtedness under its credit agreement. The Senior Secured First Lien Notes will be secured by a first priority security interest in the same collateral that is pledged for the benefit of the lenders under NRG's credit agreement, which consists of a substantial portion of the property and assets owned by NRG and the guarantors. The collateral securing the Senior Secured First Lien Notes will be released if the Company obtains an investment grade rating from two out of the three rating agencies, subject to an obligation to reinstate the collateral if such rating agencies withdraw the Company's investment grade rating or downgrade its rating below investment grade. Interest will be paid semi-annually beginning on December 15, 2019, until the maturity dates of June 15, 2024 and June 15, 2029. The proceeds from the issuance of the Senior Secured First Lien Notes, together with cash on hand, were used to repay the Company's 2023 Term Loan Facility.

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.

2019 Senior Note Redemptions

During the year ended December 31, 2019, the Company redeemed $733 million of its 6.25% Senior Notes due 2024 and recorded a loss on debt extinguishment of $29 million, which included the write-off of previously deferred debt issuance costs of $5 million.

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

Senior Notes Early Redemption

As of December 31, 2019, NRG had the following outstanding issuances of senior notes with an early redemption feature, or Senior Notes:

i. 7.250% senior notes, issued May 23, 2016 and due May 15, 2026, or the 2026 Senior Notes;

ii. 6.625% senior notes, issued August 2, 2016 and due January 15, 2027, or the 2027 Senior Notes;

iii. 5.750% senior notes, issued December 7, 2017 and due January 15, 2028, or the 2028 Senior Notes; and

iv. 5.250% senior notes, issued May 24, 2019 and due June 15, 2029 , or the 2029 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.

2026 Senior Notes

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, 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 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 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 %

2029 Senior Notes

At any time prior to June 15, 2022, NRG may redeem up to 40% of the aggregate principal amount of the 2029 Senior Notes, at a redemption price equal to 105.250% 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, provided that at least 50% of the aggregate principal amount remains outstanding immediately after the occurrence of such redemption. At any time prior to June 15, 2024, NRG may redeem all or a part of the 2029 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 102.625% of the note, plus interest payments due on the note through June 15, 2024 (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 0.50%. In addition, on or after June 15, 2024, NRG may redeem some or all of the notes at redemption prices expressed as percentages of principal amount as set forth in the following table, plus accrued and unpaid interest on the notes redeemed to the first applicable redemption date:

Redemption Period	**Redemption Percentage**
June 15, 2024 to June 14, 2025	102.625 %
June 15, 2025 to June 14, 2026	101.750 %
June 15, 2026 to June 14, 2027	100.875 %
June 15, 2027 and thereafter	100.000 %

Senior Credit Facility

On June 30, 2016, NRG replaced its previous senior credit facility with a new senior secured facility, or the Senior Credit Facility, which included 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.

2023 Term Loan Facility Repayment

On May 28, 2019, the Company repaid its $1.7 billion 2023 Term Loan Facility using the proceeds from the issuance of the Senior First Lien Notes, as well as cash on hand, resulting in a decrease of $594 million to long-term debt outstanding. The Company recorded a loss on debt extinguishment of $17 million, which included the write-off of previously deferred debt issuance costs of $13 million. As a result of the repayment of the outstanding 2023 Term Loan Facility, the Company terminated the related interest rate swap agreements, which were in-the-money, and received $25 million that was recorded as a reduction to interest expense.

Revolving Credit Facility Modification

On May 28, 2019, the Company amended its existing credit agreement to, among other thing, (i) provide for a $184 million increase in revolving commitments, resulting in aggregate revolving commitments under the amended credit agreement equal to $2.6 billion, (ii) extend the maturity date of the revolving loans and commitments under the amended credit agreement to May 28, 2024, (iii) provide for a release of the collateral securing the amended credit agreement if NRG obtains an investment grade rating form two out of the three rating agencies, subject to an obligation to reinstate the collateral if such rating agencies withdraw NRG's investment grade rating or downgrade NRG's rating below investment grade, (iv) reduce the applicable margins for borrowings under (a) ABR Revolving Loans from 1.25% to 0.75% and (b) Eurodollar Revolving Loans from 2.25% to 1.75%, (v) add a sustainability and (vi) make certain other changes to the existing covenants. As of December 31, 2019, $83 million of borrowings were outstanding.

Tax Exempt Bonds

	As of December 31,		
(In millions, except rates)	**2019**	**2018**	**Interest Rate %**
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	33	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	$ 466	

Non-Recourse Debt

The following are descriptions of certain indebtedness of NRG's subsidiaries. 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 continued to operate the applicable generation facilities and remained responsible for performance penalties and eligible for performance bonus payments, if any. Accordingly, MWG continued to account for all revenues and costs as before; however, the proceeds were recorded as a financing obligation while capacity payments by PJM to the counterparty was reflected as debt amortization and interest expense through the end of the 2018/19 delivery year. MWG amortized the upfront discount to interest expense, at an effective interest rate of 4.39%, through June 2019.

Agua Caliente Borrower I

On January 22, 2019, the lenders of the Agua Borrower I debt notified Agua Caliente Borrower 1, a subsidiary of 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 to the project. 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. On October 21, 2019, the Company repaid the outstanding amount on the notes at 102% plus accrued interest through the payment date.

Cottonwood — Letters of Credit

On January 4, 2019, the Company entered into an $80 million credit agreement to issue letters of credit, which is currently supporting the Cottonwood facility lease. Annual fees of 1.33% on the facility are paid quarterly in advance. As of December 31, 2019, the full $80 million was issued.

Note 14 — *Asset Retirement Obligations*

The Company's AROs are primarily related to the environmental obligations for nuclear decommissioning, ash disposal, site closures, 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 7, *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*.

The following table represents the balance of ARO obligations as of December 31, 2019 and 2018, along with the additions, reductions and accretion related to the Company's ARO obligations for the year ended December 31, 2019:

(In millions)	Nuclear Decommission	Other	Total
Balance as of December 31, 2018	$ 282	$ 397	$ 679
Revisions in estimates for current obligations[a]	—	27	27
Additions	—	9	9
Spending for current obligations	—	(33)	(33)
Accretion [a]	16	30	46
Balance as of December 31, 2019	$ 298	$ 430	$ 728

(a) Total ARO accretion expense includes non-Nuclear Decommissioning Trust accretion and revised asset retirement liabilities on non-operating plants

Note 15 — *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. Participation in the NRG Pension Plan for Bargained Employees depends upon whether an employee 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. NRG's obligation for both of these liabilities was revalued upon GenOn's emergence from bankruptcy resulting in an obligation of $23 million as of December 31, 2018.

NRG expects to contribute $56 million to the Company's pension plans in 2020, of which $21 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		
(In millions)	**2019**	**2018**	**2017**
Service cost benefits earned	$ 10	$ 23	$ 26
Interest cost on benefit obligation	46	44	43
Expected return on plan assets	(59)	(62)	(58)
Amortization of unrecognized net loss	3	—	4
Settlement/curtailment expense	—	7	—
Net periodic benefit cost	$ —	$ 12	$ 15

	Year Ended December 31,		
	Other Postretirement Benefits		
(In millions)	**2019**	**2018**	**2017**
Service cost benefits earned	$ 1	$ 1	$ 1
Interest cost on benefit obligation	3	4	4
Amortization of unrecognized prior service credit	(13)	(10)	(9)
Amortization of unrecognized net (gain)/loss	—	—	(1)
Curtailment gain	—	(10)	—
Net periodic benefit (credit)	$ (9)	$ (15)	$ (5)

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	
(In millions)	**2019**	**2018**	**2019**	**2018**
Benefit obligation at January 1	$ 1,222	$ 1,329	$ 83	$ 128
Service cost	10	23	1	1
Interest cost	46	44	3	4
Plan amendments	—	17	(2)	(28)
Actuarial (gain)/loss	207	(95)	16	(6)
Employee and retiree contributions	—	—	4	3
Curtailment gain	—	(20)	—	(7)
Benefit payments	(88)	(76)	(12)	(12)
Benefit obligation at December 31	1,397	1,222	93	83
Fair value of plan assets at January 1	981	1,104	—	—
Actual return on plan assets	216	(80)	—	—
Employee and retiree contributions	—	—	4	3
Employer contributions	41	33	7	9
Benefit payments	(88)	(76)	(11)	(12)
Fair value of plan assets at December 31	1,150	981	—	—
Funded status at December 31 — excess of obligation over assets	$ (247)	$ (241)	$ (93)	$ (83)

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

	As of December 31,			
	Pension Benefits		Other Postretirement Benefits	
(In millions)	**2019**	**2018**	**2019**	**2018**
Other current liabilities	$ —	$ —	$ 7	$ 7
Other non-current liabilities	247	241	86	76

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	
(In millions)	**2019**	**2018**	**2019**	**2018**
Net loss/(gain)	$ 138	$ 90	$ 7	$ (9)
Prior service cost/(credit)	2	3	(43)	(53)
Total accumulated OCI	$ 140	$ 93	$ (36)	$ (62)
Net accumulated OCI	$ 140	$ 93	$ (36)	$ (62)

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

	Year Ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
(In millions)	2019	2018	2019	2018
Net actuarial loss/(gain)	$ 50	$ 47	$ 16	$ (5)
Amortization of net actuarial (gain)/loss	(3)	—	—	—
Curtailment	—	(27)	—	2
Prior service credit	—	17	(2)	(28)
Amortization of prior service cost	—	—	12	10
Total recognized in OCI	$ 47	$ 37	$ 26	$ (21)
Net periodic benefit cost/(credit)	—	12	(9)	(15)
Net recognized in net periodic pension cost/(credit) and OCI	$ 47	$ 49	$ 17	$ (36)

The Company's estimated unrecognized loss for NRG's pension plan as of December 31, 2019 that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is $5 million. The Company's estimated unrecognized loss and unrecognized prior service credit for NRG's postretirement plan as of December 31, 2019 that will be amortized from accumulated OCI to net periodic cost over the next fiscal year is $1 million and $14 million, respectively.

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

	As of December 31,	
	Pension Benefits	
(In millions)	2019	2018
Projected benefit obligation	$ 1,397	$ 1,222
Accumulated benefit obligation	1,362	1,188
Fair value of plan assets	1,150	981

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, 2019		
(In millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
Common/collective trust investment — U.S. equity	$ —	$ 233	$ 233
Common/collective trust investment — non-U.S. equity	—	73	73
Common/collective trust investment — non-core assets	—	143	143
Common/collective trust investment — fixed income	—	272	272
Short-term investment fund	12	—	12
Subtotal fair value	$ 12	$ 721	$ 733
Measured at net asset value practical expedient:			
Common/collective trust investment — non-U.S. equity			84
Common/collective trust investment — fixed income			279
Common/collective trust investment — non-core assets			24
Partnerships/joint ventures			30
Total fair value			$ 1,150

(In millions)	Fair Value Measurements as of December 31, 2018 Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Total
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

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	2019	2018	2019	2018
Discount rate	3.26 %	4.38 %	3.26 %	4.37 %
Rate of compensation increase	3.00 %	3.00 %	— %	— %
Health care trend rate	—	—	7.5% grading to 4.5% in 2028	7.8% 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	2019	2018	2017	2019	2018	2017
Discount rate	4.38%/4.2%	3.71%/4.04%	4.26 %	4.37%	3.71% /4.08%	4.29 %
Expected return on plan assets	6.35 %	6.17 %	6.85 %	—	—	—
Rate of compensation increase	3.00 %	3.00 %	3.00 %	—	—	—
Health care trend rate	—	—	—	7.8% grading to 4.5% in 2025	8.2% grading to 4.5% in 2025	7.0% 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.

The target allocations of NRG's pension plan assets were as follows for the year ended December 31, 2019:

U.S. equity	20 %
Non-U.S. equity	13 %
Non-core assets	17 %
U.S. fixed income	50 %

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:

		Other Postretirement Benefit	
(In millions)	**Pension Benefit Payments**	**Benefit Payments**	**Medicare Prescription Drug Reimbursements**
2020	$ 84	$ 7	$ —
2021	86	6	—
2022	86	6	—
2023	86	6	—
2024	86	6	—
2025-2029	402	19	2

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:

(In millions)	**1-Percentage-Point Increase**	**1-Percentage-Point Decrease**
Effect on postretirement benefit obligation	$ 7	$ (5)

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in STP, as discussed further in Note 28, *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.

During the third quarter of 2019, STPNOC announced that the defined benefit pension plan will be frozen for non-union employees on December 31, 2021, This resulted in the curtailment of benefits, thereby requiring a remeasurement, including an update to the discount rate used to determine benefit obligations. As a result, NRG recognized a gain of $8 million related to the curtailment of benefits and an increase of $32 million to the pension liability was recorded to other comprehensive income. The Company measures the fair value of its pension assets in accordance with ASC 820, *Fair Value Measurements and Disclosures*, or ASC 820.

For the years ended December 31, 2019 and December 31, 2018, NRG reimbursed STPNOC $24 million and $13 million, respectively, for its contribution to the plans. In 2020, NRG expects to reimburse STPNOC $7 million for its contribution to the plan.

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	
(In millions)	**2019**	**2018**	**2019**	**2018**
Funded status — STPNOC benefit plans	$ (77)	$ (78)	$ (20)	$ (19)
Net periodic benefit cost/(credit)	9	8	(4)	(7)
Other changes in plan assets and benefit obligations recognized in other comprehensive (loss)/income	(13)	(7)	6	2

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,		
(In millions)	**2019**	**2018**	**2017**
Company contributions to defined contribution plans	$ 22	$ 28	$ 56

Note 16 — *Capital Structure*

For the period from December 31, 2016 to December 31, 2019, 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, 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
Shares issued under ESPP	—	46,128	46,128
Shares issued under LTIPs	1,601,904	—	1,601,904
Share repurchases	—	(36,301,882)	(36,301,882)
Balance as of December 31, 2019	421,890,790	(172,894,601)	248,996,189

Common Stock

As of December 31, 2019, NRG had 16,029,127 shares of common stock reserved for the maximum number of shares potentially issuable based on the conversion and redemption features of the long-term incentive plans.

Common stock dividends — The Company paid $0.03 quarterly dividend per common share, or $0.12 per share on an annualized basis, for years 2017, 2018 and 2019.

The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws, regulations and other contractual obligations. Beginning in the first quarter of 2020, NRG increased the annual dividend to $1.20 per share and expects to target an annual dividend growth rate of 7-9% per share in subsequent years.

On January 21, 2020, NRG declared a quarterly dividend on the Company's common stock of $0.30 per share, or $1.20 per share on an annualized basis, payable on February 18, 2020, to stockholders of record as of February 3, 2020.

Employee Stock Purchase Plan — In March 2019, the Company reopened participation in the ESPP under the Amended and Restated Employee Stock Purchase Plan, which allows eligible employees to elect to withhold between 1% and 10% of their eligible compensation to purchase shares of NRG common stock at the lesser of 95% of its market value on the offering date or 95% of the fair market value on the exercise date. An offering date will occur each April 1 and October 1. An exercise date will occur each September 30 and March 31. The ESPP plan, that was suspended in 2018, allowed eligible employees to 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 occurred each January 1 and July 1. An exercise date occurred each June 30 and December 31. As of December 31, 2019, there remained 2,885,060 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. The Company executed $1.25 billion of these share repurchases in 2018, with the remaining $0.25 billion completed in the first quarter of 2019. In 2019, the Company's board of directors authorized the Company to repurchase an additional $1.25 billion of its common stock. The Company executed $1.194 billion of these share repurchases in 2019, with the remaining $56 million completed by February 27, 2020. In addition, the Company adopted in the fourth quarter of 2019 a long-term capital allocation policy that targets allocating 50% of cash available for allocation generated each year to growth investments and 50% to be returned to shareholders. The return of capital to shareholders is expected to be completed through the increased dividend discussed above, supplemented by share repurchases.

The following table summarizes the shares repurchases made from 2018 through February 27, 2020:

	Total number of shares and share equivalents purchased	Average price paid per share and share equivalent	Amounts paid for shares and share equivalents purchased (in millions)
2018 repurchases:			
Shares repurchased under May 24, 2018 Accelerated Repurchase Agreement	10,829,903		354
Shares repurchased under September 5, 2018 Accelerated Repurchase Agreement	13,307,130		500
Other repurchases	11,097,631		396
Total Share Repurchases during 2018	35,234,664	$35.48	$ 1,250
2019 repurchases:			
Repurchases under February 28, 2019 Accelerated Share Repurchase Agreement	9,438,671		400
Other repurchases	26,863,211		1,008
Equivalent shares purchased in lieu of tax withholdings on equity compensation issuances[(a)]	936,928		36
Total Share Repurchases during 2019	37,238,810	$ 38.79	$ 1,444
2020 repurchases:			
Repurchases made subsequent to December 31, 2019	2,428,545		92
Equivalent shares purchased in lieu of tax withholdings on equity compensation issuances[(a)]	709,536		27
Total share repurchases January 1, 2020 through February 27, 2020	3,138,081	$ 37.87	$ 119

[(a)] NRG elected to pay cash for tax withholding on equity awards instead of issuing actual shares to management. The average price per equivalent shares withheld was $38.24 and $38.78 in 2020 and 2019, respectively. See Note 21, *Stock-Based Compensation*, for further discussion of the equity awards

Note 17 — *Investments Accounted for by the Equity Method and Variable Interest Entities*

Entities that are not Consolidated

NRG accounts for the Company's significant investments using the equity method of accounting. NRG's carrying value of equity investments can be impacted by a number of elements including impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates.

The following table summarizes NRG's equity method investments as of December 31, 2019:

(In millions, except percentages)

Name	Economic Interest	Investment Balance
Agua Caliente	35.0 %	213
Gladstone	37.5 %	124
Ivanpah Master Holdings, LLC	54.5 %	20
Watson Cogeneration Company	49.0 %	15
Midway-Sunset Cogeneration Company	50.0 %	9
Other[(a)]	Various	7
Total equity investments in affiliates		$ 388

(a) Refer to Note 11, *Asset Impairments*, for discussion of NRG's investment in Petra Nova Parish Holdings, LLC

(In millions)	As of December 31, 2019	As of December 31, 2018
Undistributed earnings from equity investments	$ 42	$ 34

PG&E Bankruptcy — The Agua Caliente project and two of the three Ivanpah units are party to PPAs with PG&E. Both projects have project financing with the U.S. DOE. On January 29, 2019, PG&E Corp. and subsidiary utility PG&E filed for Chapter 11 bankruptcy protection. As part of their filing, PG&E asked the Bankruptcy Court to confirm exclusive jurisdiction over their "rights to reject" PPAs or other contracts regulated by FERC. As a result of the bankruptcy filing, the Agua Caliente and Ivanpah projects have issued notices of events of default under their respective loan agreements. The Ivanpah project signed a forbearance agreement with the Department of Energy on October 25, 2019. The Company's subsidiaries are working with their partners on the projects and the loan counterparties.

On September 9, 2019, PG&E filed a plan of reorganization that would assume all power purchase agreements, including those held by the Agua Caliente project and the two Ivanpah units. On January 22, 2020 the noteholders agreed to support the PG&E plan, which will continue to provide for assumption of all power purchase agreements. The plan was subsequently amended, and a hearing before the Bankruptcy Court to consider whether the PG&E plan will be approved and confirmed is currently expected to occur on May 27, 2020. NRG's maximum exposure to loss is limited to its equity investment, which was $213 million for Agua Caliente and $20 million for Ivanpah as of December 31, 2019. See Note 13, *Debt and Finance Leases* for further discussion on Agua Caliente.

Variable Interest Entities

NRG accounts for its interests in certain entities that are considered VIEs under ASC 810, *Consolidation*, for which NRG is not the primary beneficiary, under the equity method.

Through its consolidated subsidiary, NRG Solar Ivanpah LLC, NRG owns a 54.5% interest in Ivanpah Master Holdings, LLC, or Ivanpah, the owner of three solar electric generating projects located in the Mojave Desert with a total capacity of 393 MW. NRG considers this investment a VIE under ASC 810 and NRG is not considered the primary beneficiary. The Company accounts for its interest under the equity method of accounting.

The Ivanpah solar electric generating projects were funded in large part by loans guaranteed by the U.S. DOE and equity from the projects' partners. During the first quarter of 2018, all interested parties sought a restructuring of Ivanpah's debt in order to avoid a potential event of default with respect to the loans in connection with several recent events. Ensuing negotiations culminated in a settlement during the second quarter of 2018 between the parties which resulted in certain transactions, including the release of reserves totaling $95 million to fund equity distributions to the partners, which reduced the equity at risk, and the prepayment of certain of the debt balance outstanding, and the amendment of certain of Ivanpah's governing documents. The equity distributions and prepayment of debt were funded by the agreed upon release of reserve funds. These events were considered to be a reconsideration event in accordance with ASC 810. As a result, NRG determined that it is not the primary beneficiary and deconsolidated Ivanpah. NRG recognized a loss of $22 million on the deconsolidation and subsequent recognition of Ivanpah as an equity method investment. The deconsolidation of Ivanpah reduced the Company's assets by approximately $1.3 billion, which was primarily property, plant and equipment, and reduced the Company's liabilities by $1.2 billion, which was primarily long-term debt.

Other Equity Investments

Gladstone — Through a joint venture, NRG owns a 37.5% interest in Gladstone, a 1,613 MW coal-fueled power generation facility in Queensland, Australia. The power generation facility is managed by the joint venture participants and the facility is operated by NRG. Operating expenses incurred in connection with the operation of the facility are funded by each of the participants in proportion to their ownership interests. Coal is sourced from local mines in Queensland. NRG and the joint venture participants receive their respective share of revenues directly from the off takers in proportion to the ownership interests in the joint venture. Power generated by the facility is primarily sold to an adjacent aluminum smelter, with excess power sold to the Queensland Government-owned utility under long-term supply contracts. NRG's investment in Gladstone was $124 million as of December 31, 2019.

Entities that are Consolidated

The Company has a controlling financial interest in certain entities which have been identified as VIEs under ASC 810. These arrangements are related to tax equity arrangements entered into with third-parties in order to finance the cost of solar energy systems under operating leases eligible for certain tax credits as further described in Note 2, *Summary of Significant Accounting Policies*.

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

(In millions)	December 31, 2019	December 31, 2018
Current assets	$ 3	$ 3
Net property, plant and equipment	71	76
Other long-term assets	27	28
Total assets	101	107
Current liabilities	4	2
Long-term debt	24	29
Other long-term liabilities	8	7
Total liabilities	36	38
Redeemable noncontrolling interests	20	19
Net assets less noncontrolling interests	$ 45	$ 50

Note 18 — *Earnings/(Loss) Per Share*

Basic income/(loss) per common share is computed by dividing net income/(loss) by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted income/(loss) per share is computed in a manner consistent with that of basic income/(loss) per share, while giving effect to all potentially dilutive common shares that were outstanding during the period.

Dilutive effect for equity compensation and other equity instruments — The outstanding non-qualified stock options, non-vested restricted stock units, and market stock units and relative performance stock units are not considered outstanding for purposes of computing basic income/(loss) per share. However, these instruments are included in the denominator for purposes of computing diluted income/(loss) per share under the treasury stock method. The 2048 Convertible Senior Notes are convertible, under certain circumstances, into the Company’s common stock, cash or combination thereof (at NRG's option). There is no dilutive effect for the 2048 Convertible Senior Notes due to the Company’s expectation to settle the liability in cash.

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

	Year Ended December 31,		
(In millions, except per share amounts)	**2019**	**2018**	**2017**
Basic income/(loss) per share attributable to NRG, Inc;			
Net income/(loss) attributable to NRG Energy, Inc. common stockholders	$ 4,438	$ 268	$ (2,153)
Weighted average number of common shares outstanding-basic	262	304	317
Income/(Loss) per weighted average common share — basic	$ 16.94	$ 0.88	$ (6.79)
Diluted income/(loss) per share attributable to NRG, Inc;			
Net income/(loss) attributable to NRG Energy, Inc. common stockholders	$ 4,438	$ 268	$ (2,153)
Weighted average number of common shares outstanding-basic	262	304	317
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	2	4	—
Weighted average number of common shares outstanding-diluted	264	308	317
Income/(Loss) per weighted average common share — diluted	$ 16.81	$ 0.87	$ (6.79)

The following table summarizes NRG's outstanding equity instruments that are anti-dilutive and were not included in the computation of the Company's diluted income/(loss) per share:

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Equity compensation plans	—	—	5

Note 19 — *Segment Reporting*

As of December 31, 2019, the Company's reportable segments were Generation, Retail and Corporate. Retail included Mass market and C&I customers, as well as other distributed and reliability products. Generation included all power plant activities, as well as renewables. The Company began managing its integrated model based on the combined results of the retail and wholesale generation businesses with a geographical focus in 2020. As a result, the Company changed its business segments to Texas, East and West/Other beginning in the first quarter of 2020. The Company's updated segment structure reflects how management currently makes financial decisions and allocates resources. All affected disclosures presented herein have been recast to reflect these changes for all periods presented. For further discussion, refer to Note 1, *Nature of Business*.

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

On February 4, 2019, the Company completed the sale and deconsolidation of South Central Portfolio. On August 31, 2018, NRG deconsolidated NRG Yield Inc., its Renewables Platform and Carlsbad for financial reporting purposes. In 2018, the financial information for historical periods was recast to reflect the presentation of discontinued operations within the corporate segment. Refer to Note 4, *Acquisitions, Discontinued Operations and Dispositions*, for further discussion.

The Company had no customer that comprised more than 10% of the Company's consolidated revenues during the years ended December 31, 2019 and 2017. The company had one customer in the Texas segment that comprised 11% of the Company's consolidated revenues during the year ended December 31, 2018.

Intersegment sales are accounted for at market.

(In millions)	For the Year Ended December 31, 2019 Texas	East	West/Other	Corporate[a]	Eliminations	Total
Operating revenues[a]	$ 7,069	$ 2,319	$ 440	$ —	$ (7)	$ 9,821
Operating expenses	5,818	1,895	397	50	(7)	8,153
Depreciation and amortization	188	121	33	31	—	373
Impairment losses	1	—	4	—	—	5
Development costs	3	3	1	—	—	7
Total operating cost and expenses	6,010	2,019	435	81	(7)	8,538
Gain on sale of assets	—	1	—	6	—	7
Operating income/(loss)	1,059	301	5	(75)	—	1,290
Equity in (losses)/earnings of unconsolidated affiliates	(4)	—	6	—	—	2
Impairment losses on investments	(103)	—	—	(5)	—	(108)
Other income, net	20	6	10	30	—	66
Loss on debt extinguishment	—	—	(3)	(48)	—	(51)
Interest expense	—	(18)	(10)	(385)	—	(413)
Income/(loss) from continuing operations before income taxes	972	289	8	(483)	—	786
Income tax expense/(benefit)	—	2	1	(3,337)	—	(3,334)
Net income from continuing operations	972	287	7	2,854	—	4,120
Gain from discontinued operations, net of income tax	—	—	—	321	—	321
Net Income	972	287	7	3,175	—	4,441
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	3	—	—	3
Net income attributable to NRG Energy, Inc.	$ 972	$ 287	$ 4	$ 3,175	$ —	$ 4,438
Balance sheet						
Equity investments in affiliates	$ 6	$ —	$ 382	$ —	$ —	$ 388
Capital expenditures	136	30	25	37	—	228
Goodwill[b]	325	254	—	—	—	579
Total assets	$ 5,711	$ 2,160	$ 1,190	$ 8,342	$ (4,872)	$ 12,531

(a) Inter-segment sales and inter-segment net derivative gains and losses included in operating revenues	$ 1	$ 8	$ (2)	$ —	$ —	$ 7

(b) Goodwill was allocated based on the regions in which the business operates and are expected to benefit using a relative fair value approach

(In millions)	For the Year Ended December 31, 2018					
	Texas	East	West/Other	Corporate[a]	Eliminations	Total
Operating revenues[a]	$ 6,401	$ 2,371	$ 724	$ —	$ (18)	$ 9,478
Operating expenses	5,399	2,024	467	125	(18)	7,997
Depreciation and amortization	156	105	127	33	—	421
Impairment losses	5	82	12	—	—	99
Development costs	3	3	3	2	—	11
Total operating cost and expenses	5,563	2,214	609	160	(18)	8,528
Gain on sale of assets	4	—	(2)	30	—	32
Operating income/(loss)	842	157	113	(130)	—	982
Equity in (losses)/earnings of unconsolidated affiliates	(3)	—	13	(1)	—	9
Impairment losses on investments	(15)	—	—	—	—	(15)
Other income/(loss), net	13	2	4	(1)	—	18
Loss on debt extinguishment	—	—	—	(44)	—	(44)
Interest expense	—	(22)	(39)	(422)	—	(483)
Income/(loss) from continuing operations before income taxes	837	137	91	(598)	—	467
Income tax expense	—	1	—	6	—	7
Net income/(loss) from continuing operations	837	136	91	(604)	—	460
Loss from discontinued operations, net of income tax	—	—	—	(192)	—	(192)
Net Income/(loss)	837	136	91	(796)	—	268
Less: Net income/(loss) attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	5	(5)	—	—
Net income/(loss) attributable to NRG Energy, Inc.	$ 837	$ 136	$ 86	$ (791)	$ —	$ 268
Balance sheet						
Equity investments in affiliates	$ 6	$ —	406	$ —	$ —	$ 412
Capital expenditures	143	171	29	45	—	388
Goodwill[b]	320	253	—	—	—	573
Total assets	$ 5,357	$ 2,187	$ 1,548	$ 6,631	$ (5,095)	$ 10,628

(a) Inter-segment sales and inter-segment net derivative gains and losses included in operating revenues	$ 19	$ (5)	4	$ —	$ —	$ 18

(b) Goodwill was allocated based on the regions in which the business operates and are expected to benefit using a relative fair value approach

(In millions)	For the Year Ended December 31, 2017 Texas	East	West/Other	Corporate[(a)]	Eliminations	Total
Operating revenues[(a)]	$ 6,318	$ 2,009	$ 788	$ 6	$ (47)	$ 9,074
Operating expenses	5,393	1,684	498	239	(48)	7,766
Depreciation and amortization	258	112	194	35	(3)	596
Impairment losses	1,317	106	111	—	—	1,534
Development costs	4	6	6	6	—	22
Total operating costs and expenses	6,972	1,908	809	280	(51)	9,918
Other income - affiliate	—	—	—	87	—	87
Gain/(loss) on sale of assets	5	15	(5)	1	—	16
Operating (loss)/income	(649)	116	(26)	(186)	4	(741)
Equity in (losses)/earnings of unconsolidated affiliates	(22)	—	10	(2)	—	(14)
Impairment losses on investments	(69)	—	(6)	(4)	—	(79)
Other (expense)/income, net	(2)	4	22	27	—	51
Loss on debt extinguishment	—	—	—	(49)	—	(49)
Interest expense	—	(29)	(77)	(451)	—	(557)
(Loss)/income from continuing operations before income taxes	(742)	91	(77)	(665)	4	(1,389)
Income tax benefit	—	—	(6)	(38)	—	(44)
Net (loss)/income from continuing operations	(742)	91	(71)	(627)	4	(1,345)
Loss from discontinued operations, net of income tax	—	—	—	(992)	—	(992)
Net (loss)/income	(742)	91	(71)	(1,619)	4	(2,337)
Less: Net income/(loss) attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	1	(189)	4	(184)
Net (loss)/income attributable to NRG Energy, Inc.	$ (742)	$ 91	$ (72)	$ (1,430)	$ —	$ (2,153)
(a) Inter-segment sales and inter-segment net derivative gains and losses included in operating revenues	$ 41	$ 1	(4)	$ 9	$ —	$ 47

Note 20 — *Income Taxes*

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

(In millions, except effective income tax rate)	Year Ended December 31, 2019	2018	2017
Current			
State	$ 2	$ 6	$ 19
Foreign	4	—	—
Total — current	6	6	19
Deferred			
U.S. Federal	(3,000)	(16)	(60)
State	(340)	16	(5)
Foreign	—	1	2
Total — deferred	(3,340)	1	(63)
Total income tax (benefit)/expense	$ (3,334)	$ 7	$ (44)
Effective income tax rate	(424.2)%	1.5 %	3.2 %

During the year ended December 31, 2019, NRG released the majority of its valuation allowance against its U.S. federal and state deferred tax assets, resulting in a non-cash benefit to income tax expense of approximately $3.5 billion. In making the determination to release the majority of the valuation allowance as of December 31, 2019, the Company evaluated a number of factors, including its recent history of pre-tax earnings, utilization of $593 million of NOLs in 2019, as well as its forecasted future pre-tax earnings. Based on this evaluation, the Company determined that the majority of its future tax benefits are more-likely-than-not to be realized. Given the Company's current level of pre-tax earnings and forecasted future pre-tax earnings, the Company expects to generate income before taxes in the U.S. in future periods at a level that would fully utilize its U.S. federal NOL carryforwards and the majority of its state NOL carryforwards prior to their expiration.

The following represented the domestic and foreign components of income/(loss) from continuing operations before income taxes:

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
U.S.	$ 771	$ 468	$ (1,406)
Foreign	15	(1)	17
Total	$ 786	$ 467	$ (1,389)

Reconciliations of the U.S. federal statutory tax rate to NRG's effective tax rate were as follows:

	Year Ended December 31,		
(In millions, except effective income tax rate)	**2019**	**2018**	**2017**
Income/(loss) from continuing operations before income taxes	$ 786	$ 467	$ (1,389)
Tax at federal statutory tax rate	165	98	(486)
State taxes	13	18	19
Foreign operations	—	—	2
Permanent differences	(9)	7	—
Valuation allowance - current period activities	(3,492)	(106)	455
Book goodwill impairment	—	—	30
Deferred impact of state tax rate changes	12	—	—
Production tax credits ("PTC")	—	(7)	(8)
Recognition of uncertain tax benefits	(10)	1	(5)
Alternative minimum tax ("AMT") refundable credit	—	(4)	(64)
Tax Act - corporate income tax rate change	—	—	665
Valuation allowance due to corporate income tax rate change	—	—	(660)
Other	(13)	—	8
Income tax (benefit)/expense	$ (3,334)	$ 7	$ (44)
Effective income tax rate	(424.2)%	1.5 %	3.2 %

For the year ended December 31, 2019, NRG's effective income tax rate was lower than the federal statutory tax rate of 21% primarily due to the tax benefit from the release of the valuation allowance.

For the year ended December 31, 2018, NRG's effective income tax rate was lower 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 AMT credit receivable, partially offset by current state tax expense.

For the year ended December 31, 2017, NRG's effective income tax rate was lower 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 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.

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

	As of December 31,	
(In millions)	**2019**	**2018**
Deferred tax assets:		
Deferred compensation, accrued vacation and other reserves	$ 81	$ 134
Difference between book and tax basis of property	548	554
Goodwill	—	11
Differences between book and tax basis of contracts	—	38
Pension and other postretirement benefits	86	87
Equity compensation	11	9
Bad debt reserve	13	14
U.S. Federal net operating loss carryforwards	2,116	2,241
Foreign net operating loss carryforwards	105	63
State net operating loss carryforwards	360	379
Federal and state tax credit carryforwards	384	381
Federal benefit on state uncertain tax positions	4	6
Intangibles amortization (excluding goodwill)	—	21
Interest disallowance carryforward per §163(j) of the Tax Act	82	102
Inventory obsolescence	7	7
Other	3	—
Discontinued operations	—	17
Total deferred tax assets	3,800	4,064
Deferred tax liabilities:		
Emissions allowances	19	15
Derivatives, net	27	37
Goodwill	8	—
Intangibles amortization (excluding goodwill)	15	—
Equity method investments	201	180
Convertible Debt	19	21
Other	—	1
Discontinued operations	—	36
Total deferred tax liabilities	289	290
Total deferred tax assets less deferred tax liabilities	3,511	3,774
Valuation allowance	(242)	(3,812)
Discontinued operations	—	19
Total deferred tax assets/(liabilities), net of valuation allowance	$ 3,269	$ (19)

The following table summarizes NRG's net deferred tax position as presented in the consolidated balance sheets:

	As of December 31,	
(In millions)	**2019**	**2018**
Deferred tax asset	$ 3,286	$ 46
Deferred tax liability	(17)	(65)
Net deferred tax asset/(liability)	$ 3,269	$ (19)

The primary driver for the change from a $19 million net deferred tax liability as of December 31, 2018 to a net deferred tax asset of $3.3 billion as of December 31, 2019 is the release in the Company’s valuation allowance, partially offset by utilization of federal and state NOLs.

Deferred tax assets and valuation allowance

Net deferred tax balance — As of December 31, 2019 and 2018, NRG recorded a net deferred tax asset, excluding valuation allowance, of $3.5 billion and $3.8 billion, respectively. The Company believes certain state net operating losses may not be realizable under the more-likely-than-not measurement and as such, a valuation allowance was recorded as of December 31, 2019 as discussed below.

NOL carryforwards — As of December 31, 2019, the Company had tax effected cumulative U.S. NOLs consisting of carryforwards for federal and state income tax purposes of $2.1 billion and $360 million, respectively. The Company estimates it will need to generate future taxable income to fully realize the net federal deferred tax asset before the expiration of certain carryforwards commences in 2031. In addition, NRG has cumulative foreign NOL carryforwards of $105 million with no expiration date.

Valuation allowance — As of December 31, 2019, the Company's tax-effected valuation allowance was $242 million, consisting of state NOL carryforwards and foreign NOL carryforwards. The valuation allowance was recorded based on the assessment of cumulative and forecasted pre-tax book earnings and the future reversal of existing taxable temporary differences.

Taxes Receivable and Payable

As of December 31, 2019, NRG recorded a current tax payable of $13 million that represents a tax liability due for state income taxes that is primarily comprised of Texas margin tax. NRG has a tax receivable of $1 million, comprised of refunds due from state income tax estimated payments and return filings.

Uncertain tax benefits

NRG has identified uncertain tax benefits with after-tax value of $15 million and $26 million as of December 31, 2019 and 2018, for which NRG has recorded a non-current tax liability of $17 million and $30 million, respectively. The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense. The Company recognized expense of $1 million related to interest in each of the years ended December 31, 2019, 2018 and 2017. As of December 31, 2019 and 2018, NRG had cumulative interest and penalties related to these uncertain tax benefits of $2 million and $4 million, respectively.

Tax jurisdictions — NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including operations located in Australia.

The Company is no longer subject to U.S. federal income tax examinations for years prior to 2016. With few exceptions, state and local income tax examinations are no longer open for years before 2011.

The following table summarizes uncertain tax benefits activity:

	As of December 31,	
(In millions)	**2019**	**2018**
Balance as of January 1	$ 26	$ 30
Increase due to current year positions	2	4
Settlements, payments and statute closure	(13)	(8)
Uncertain tax benefits as of December 31	$ 15	$ 26

Note 21 — *Stock-Based Compensation*

NRG Energy, Inc. Long-Term Incentive Plan

On April 27, 2017, the NRG LTIP was amended to increase the number of shares available for issuance by 3,000,000. As of December 31, 2019 and 2018, a total of 25,000,000 shares of NRG common stock were authorized for issuance under the NRG LTIP. There were 9,935,750 and 8,564,611 shares of common stock remaining available for grants under the NRG LTIP as of December 31, 2019 and 2018, respectively. The NRG LTIP is subject to adjustments in the event of reorganization, recapitalization, stock split, reverse stock split, stock dividend, and a combination of shares, merger or similar change in NRG's structure or outstanding shares of common stock.

Upon adoption of the amended NRG LTIP effective April 27, 2017, no shares of NRG common stock remain available for future issuance under the NRG GenOn LTIP. As of December 31, 2019 and 2018, there were 319,264 and 520,182 shares of common stock remaining available for grants under the NRG GenOn LTIP, respectively.

Restricted Stock Units

As of December 31, 2019, RSUs granted under the Company's LTIPs typically have three-year graded vesting schedules beginning on the grant date. Fair value of the RSUs granted during 2019 is derived from the closing price of NRG common stock on the grant date. The following table summarizes the Company's non-vested RSU awards and changes during the year:

	Units	Weighted Average Grant Date Fair Value per Unit
Non-vested at December 31, 2018	1,458,082	$ 16.16
Granted	266,938	37.37
Forfeited	(73,905)	24.73
Vested	(933,876)	14.20
Non-vested at December 31, 2019	717,239	25.56

The total fair value of RSUs vested during the years ended December 31, 2019, 2018, and 2017 was $36 million, $42 million, and $19 million, respectively. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2019, 2018, and 2017 was $37.37, $28.90, and $12.44, respectively.

Deferred Stock Units

DSUs represent the right of a participant to be paid one share of NRG common stock at the end of a deferral period established under the terms of the award. DSUs granted under the Company's LTIPs are fully vested at the date of issuance. Fair value of the DSUs, which is based on the closing price of NRG common stock on the date of grant, is recorded as compensation expense in the period of grant.

The following table summarizes the Company's outstanding DSU awards and changes during the year:

	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2018	331,915	$ 22.94
Granted	57,630	34.84
Converted to Common Stock	(58,322)	28.93
Outstanding at December 31, 2019	331,223	23.98

The aggregate intrinsic values for DSUs outstanding as of December 31, 2019, 2018, and 2017 were approximately $13 million, $13 million, and $12 million, respectively. The aggregate intrinsic values for DSUs converted to common stock for the years ended December 31, 2019, 2018, and 2017 were $2 million, $6 million, and $4 million, respectively. The weighted average grant date fair value of DSUs granted during the years ended December 31, 2019, 2018, and 2017 was $34.84, $33.43, and $16.76, respectively.

Performance Stock Units

PSUs entitle the recipient to stock upon vesting. The amount of the award is subject to the Company's achievement of certain performance measures over the vesting period. PSUs include RPSUs and MSUs. As of December 31, 2019, non-vested PSUs consist primarily of RPSUs.

Relative Performance Stock Units — RPSUs are restricted grants where the quantity of shares increases and decreases alongside the Company's Total Shareholder Return, or TSR, relative to the TSR of the Company's current proxy peer group and the total returns of select indexes, or Peer Group. Each RPSU represents the potential to receive NRG common stock after the completion of the performance period, typically three years of service from the date of grant. The number of shares of NRG common stock to be paid (if any) as of the vesting date for each RPSU will depend on the Company’s percentile rank within the Peer Group. The number of shares of common stock to be paid as of the vesting date for each RPSU is linearly interpolated for TSR performance between the following points: (i) 0% if ranked below the 25th percentile; (ii) 25% if ranked at the 25th percentile; (iii) 100% if ranked at the 55th percentile (or the 65th percentile if the Company's absolute TSR is less than negative 15%); and (iv) 200% if ranked at the 75th percentile or above. The value of the common stock on the date of grant is based on the closing price of NRG common stock on the date of grant.

Market Stock Units — MSUs are restricted grants where the quantity of shares increases and decreases alongside the Company's TSR. Each MSU represents the potential to receive NRG common stock after the completion of the performance period, typically three years of service from the date of grant. The number of shares of common stock to be paid as of the vesting date for each MSU is : (i) zero shares, if the TSR has decreased by more than 25% over the performance period, (ii) three-quarters of one share, if the TSR has decreased by 25% over the performance period; (iii) interpolated between three-quarters of one share and one share, if the TSR has decreased less than 25% over the performance period; (iv) one share, if there is no change in TSR over the performance period; (v) interpolated between one share and two shares, if TSR increases less than 100% during the performance period; and (vi) two shares, if the TSR increases 100% over the performance period. The value of the common stock on the date of grant was based on the closing price of NRG common stock on the date of grant. The Company last granted MSUs during the year ended December 31, 2016.

The following table summarizes the Company's non-vested PSU awards and changes during the year:

	Units	Weighted Average Grant-Date Fair Value per Unit
Non-vested at December 31, 2018	1,710,634	$ 19.12
Granted[(a)]	936,889	22.50
Forfeited	(37,526)	23.04
Vested[(b)]	(1,409,456)	14.72
Non-vested at December 31, 2019[(c)]	1,200,541	26.65

(a) The weighted average grant date fair value per unit includes RPSUs that were granted during 2019 with grant date fair value of $45.77 and MSUs with 2016 grant date fair value of $14.72, that due to vesting at 200%, were considered additional grants in 2019

(b) MSUs granted during 2016 vested during 2019 at 200%

(c) Non-vested units includes 8,645 MSUs

The weighted average grant date fair value of PSUs granted during the years ended December 31, 2019, 2018, and 2017, was $22.50, $35.36, and $15.91, respectively.

The fair value of PSUs is estimated on the date of grant using a Monte Carlo simulation model and expensed over the service period, which equals the vesting period. Significant assumptions used in the fair value model with respect to the Company's PSUs are summarized below:

	2019	2018	2017	2016
	RPSUs	RPSUs	RPSUs	MSUs
Expected volatility	40.72 %	47.52 %	43.96 %	34.33 %
Expected term (in years)	3	3	3	3
Risk free rate	2.45 %	2.01 %	1.5 %	1.31 %

For the years ended December 31, 2019 and 2018, expected volatility is calculated based on NRG's historical stock price volatility data over the period commensurate with the expected term of the PSU, which equals the vesting period.

Non-Qualified Stock Options

All NQSOs granted under the Company's LTIP were fully vested as of December 31, 2019, 2018, and 2017. No NQSOs were granted in 2019, 2018 or 2017. NRG recognizes compensation costs for NQSOs over the requisite service period for the entire award. No compensation expense was recognized during 2019, 2018 and 2017 as it was fully recognized in prior years. The maximum contractual term is 10 years for NRG's outstanding NQSOs.

The following table summarizes the Company's NQSO activity and changes during the year:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2018	279,934	$ 25.04	2	$ 4
Expired	(8,254)	26.76		
Exercised	(137,282)	24.67		
Outstanding at December 31, 2019	134,398	25.31	1	2
Exercisable at December 31, 2019	134,398	25.31	1	2

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

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Total intrinsic value of options exercised	$ 2	$ 10	$ 1
Cash received from options exercised	3	24	4

Supplemental Information

The following table summarizes NRG's total compensation expense recognized for the years presented, as well as total non-vested compensation costs not yet recognized and the period over which this expense is expected to be recognized as of December 31, 2019, for each of the types of awards issued under the LTIPs. Minimum tax withholdings of $36 million, $19 million, and $5 million for the years ended December 31, 2019, 2018, and 2017, respectively, are reflected as a reduction to additional paid-in capital on the Company's consolidated balance sheets.

				Non-vested Compensation Cost	
(In millions, except weighted average data)	Compensation Expense			Unrecognized Total Cost	Weighted Average Recognition Period Remaining (In years)
	Year Ended December 31,			As of December 31,	
Award	**2019**	**2018**	**2017**	**2019**	**2019**
RSUs	9	12	15	8	1.06
DSUs	2	2	2	—	0.00
MSUs	—	4	5	—	0.50
RPSUs	10	7	3	9	0.71
PRSUs[(a)]	11	16	13	10	1.05
Total[(b)]	$ 32	$ 41	$ 38	$ 27	
Tax detriment recognized	$ (12)	$ (4)	$ (5)		

(a) Phantom Restricted Stock Units, PRSUs, are liability-classified time-based awards that typically vest ratably over a three-year period. The amount to be paid upon vesting is based on NRG's closing stock price for the period

(b) Does not include compensation expense of $1 million, and $6 million for the years ended 2018, and 2017, respectively, which was recorded in loss from discontinued operations in the Company's consolidated statements of operations

Note 22 — *Related Party Transactions*

NRG provides services to some of its equity method investments under operations and maintenance agreements. Fees for the services under these agreements include recovery of NRG's costs of operating the plants. Certain agreements also include fees for administrative service, a base monthly fee, profit margin and/or annual incentive bonus.

The following table summarizes NRG's material related party transactions with third party affiliates:

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Revenues from Related Parties Included in Operating Revenues			
Gladstone	$ 4	$ 3	$ 3
GenConn[(a)]	—	4	5
Ivanpah[(b)]	35	20	—
Midway-Sunset	5	5	—
Total	$ 44	$ 32	$ 8

(a) As of August 31, 2018, NRG no longer had an ownership interest in GenConn as a result of the sale of its ownership interests in NRG Yield, Inc. and its Renewables Platform

(b) Also includes fees under project management agreements with each project company. Ivanpah became a related party to NRG upon deconsolidation in the second quarter of 2018

Services Agreement and Transition Services Agreement with GenOn

The Company provided GenOn with various management, personnel and other services, which included 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, or the Services Agreement. The annual fees under the Services Agreement was approximately $193 million and management had concluded that this method of charging overhead costs was reasonable. In connection with the Restructuring Support Agreement in 2017, NRG agreed to provide shared services to GenOn under the Services Agreement for an adjusted annualized fee of $84 million.

In December 2017, in conjunction with the confirmation of the GenOn Entities' plan of reorganization, the Services Agreement was terminated and replaced by the transition services agreement. Under the transition services agreement, NRG provided the shared services and other separation services at an annualized rate of $84 million, subject to certain credits and adjustments. GenOn provided notice to NRG of its intent to terminate the transition services agreement effective August 15, 2018 and in connection with the settlement agreement described in Note 4, *Acquisitions, Discontinued Operations and Dispositions*, all amounts owed and payable to NRG were settled against the $28 million credit provided for in the Restructuring Support Agreement. For the year ended December 31, 2018 , NRG recorded approximately $53 million, under the transition services agreement against selling, general and administrative expenses post-Chapter 11 Filing. For the year ended December 31, 2017 , NRG recorded other income - affiliate related to these services of $87 million prior to the Chapter 11 Filing and $42 million against selling, general and administrative expenses post-Chapter 11 Filing.

Credit Agreement with GenOn

NRG and GenOn were party to a secured intercompany revolving credit agreement. The intercompany revolving credit agreement provided for a $500 million revolving credit facility, all of which was available for revolving loans and letters of credit. As a result of the GenOn bankruptcy, no additional revolving loans or letters of credit were available to GenOn. As of December 31, 2017, $92 million of letters of credit were issued and outstanding. As a result of the GenOn Settlement, as further described in Note 4, *Acquisitions, Discontinued Operations and Dispositions*, outstanding borrowings were repaid to NRG, except for certain LCs issued which are further discussed below. The facility was terminated on December 14, 2018.

On December 7, 2018, NRG, GenOn and REMA entered into an agreement to support the outstanding LCs from the intercompany revolving credit agreement previously issued. As of December 31, 2019, $14 million was outstanding. GenOn and REMA have provided support for these outstanding LCs through back-to-back letters of credit and cash collateral. The outstanding letters of credit will continue to accrue any contractual fees and expenses until they are terminated.

Note 23 — *Commitments and Contingencies*

Coal, Gas and Transportation Commitments

NRG has entered into long-term contractual arrangements to procure fuel and transportation services for the Company's generation assets.

As of December 31, 2019, the Company's minimum commitments under such outstanding agreements are estimated as follows:

Period		**(In millions)**
2020	$	124
2021		125
2022		73
2023		53
2024		62
Thereafter		139
Total[(a)]	$	576

(a) Actual coal, gas and transportation purchases are significantly higher than these estimated minimum unconditional long- term firm commitments

For the years ended December 31, 2019, 2018, and 2017, the Company purchased $1.2 billion, $1.2 billion, and $1.1 billion, respectively under such arrangements.

Purchased Power Commitments

NRG has purchased power contracts of various quantities and durations, including renewable purchased power agreements under PPAs with third-party project developers, that are not classified as derivative assets and liabilities and do not qualify as operating leases. These contracts are not included in the consolidated balance sheet as of December 31, 2019. Minimum purchase commitment obligations are as follows as of December 31, 2019:

Period	(In millions)
2020	$ 35
2021	49
2022	68
2023	56
2024	56
Thereafter	349
Total	$ 613

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of property and assets owned by NRG and the guarantors of its senior debt. 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 a claim under the first lien program. As of December 31, 2019, hedges under the first lien were in-the-money for NRG on a counterparty aggregate basis.

Jewett Mine Lignite Contract

The Company's Limestone facility historically burned lignite obtained from the Jewett mine, which was operated by Texas Westmoreland Coal Co., or TWCC. On or about March 15, 2019, the Jewett mine and related lignite supply agreement with NRG were acquired by Westmoreland Mining LLC pursuant to a plan of reorganization confirmed by the U.S. Bankruptcy Court for the Southern District of Texas. Active mining under the lignite supply agreement ceased as of December 31, 2016; however, under the terms of the lignite supply agreement, the mine operator remains responsible for undertaking reclamation activities and NRG is responsible for reclamation costs. NRG has recorded an adequate ARO liability. The Railroad Commission of Texas has imposed a bond obligation of approximately $99 million for the reclamation of the Jewett mine, which NRG supports through surety bonds. The cost of the reclamation may exceed the value of the bonds. Additionally, the lignite supply agreement obligates NRG to provide additional performance assurance if required by the Railroad Commission of Texas.

Nuclear Insurance

STP maintains required insurance coverage for liability claims arising from nuclear incidents pursuant to the Price-Anderson Act. The current liability limit per incident is $13.9 billion, subject to change to account for the effects of inflation and the number of licensed reactors. An inflation adjustment must be made at least once every five years with the next due no later than September 10, 2023. Under the Price-Anderson Act, owners of nuclear power plants in the U.S. are required to purchase primary insurance limits of $450 million for each operating site. In addition, the Price-Anderson Act requires an additional layer of protection through mandatory participation in a retrospective rating plan for power reactors resulting in an additional $13.5 billion in funds available for public liability claims. The current maximum assessment per incident, per reactor, is approximately $138 million, taking into account a 5% adjustment for administrative fees, payable at approximately $21 million per year, per reactor. NRG would be responsible for 44% of the maximum assessment, or $9 million per year, per reactor, and a maximum of $61 million per incident. In addition, the U.S. Congress retains the ability to impose additional financial requirements on the nuclear industry to pay liability claims that exceed $14 billion for a single incident. The liabilities of the co-owners of STP with respect to the retrospective premium assessments for nuclear liability insurance are joint and several.

STP purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Limited, or NEIL, and European Mutual Association for Nuclear Insurance, or EMANI, both of which are industry mutual insurance companies, of which STP is a member. STP has purchased $2.75 billion in limits for nuclear events and $1.0 billion in limits for non-nuclear events. The nuclear event limit remains the maximum available from NEIL. The upper $1.25 billion in nuclear events limits (excess of the first $1.5 billion in nuclear events limits) is a single limit blanket policy shared with two Diablo Canyon nuclear reactors, which have no affiliation with the Company. This shared limit is not subject to automatic reinstatement in the event of a loss. The NEIL primary policy covers both nuclear and non-nuclear property damage events, and a NEIL companion policy provides Accidental Outage coverage for the co-owners of STP's lost revenue following a property damage event, at a weekly indemnity limit of $2.5 million per unit up to a maximum of $274 million nuclear per unit and $184 million non-nuclear per unit, and is subject to an eight-week waiting period. NRG also purchases an Accidental Outage policy from NEIL, which provides protection for lost revenue due to an insurable event. This coverage allows for reimbursement up to $1.98 million per week per unit up to a maximum of $216 million nuclear and $144 million non-nuclear, and is subject to an eight-week waiting period. Under the terms of the NEIL and EMANI policies, member companies may be assessed up to ten and six times their annual premiums respectively if the NEIL or EMANI Board of Directors determines their surplus has been depleted due to the payment of property losses at any of the licensed reactors in a single policy year. NEIL and EMANI require that their members maintain an investment grade credit rating or insure their annual retrospective obligation by providing a financial guarantee, letter of credit, deposit premium, or an insurance policy. NRG has purchased an insurance policy from NEIL and EMANI to guarantee the Company's obligation; however note the NEIL aspect of this insurance will only respond to retrospective premium adjustments assessed within twenty-four months after the policy term, whereas NEIL's Board of Directors can make such an adjustment up to 6 years after the policy expires.

Contingencies

The Company's material legal proceedings are described below. The Company believes that it has valid defenses to these legal proceedings and intends to defend them vigorously. NRG records accruals 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. As applicable, the Company has established an adequate accrual for the applicable legal matters, including regulatory and environmental matters as further discussed in Note 24, *Regulatory Matters*, and Note 25, *Environmental Matters*. In addition, legal costs are expensed as incurred. Management has assessed each of the following matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, the Company is unable to predict the outcome of these legal proceedings or reasonably estimate the scope or amount of any associated costs and potential liabilities. As additional information becomes available, management adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of the Company's liabilities and contingencies could be at amounts that are different from its currently recorded accruals and that such difference could be material.

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect NRG's consolidated financial position, results of operations, or cash flows.

Midwest Generation Asbestos Liabilities — The Company, through its subsidiaries, settled the indemnification claims brought by Commonwealth Edison Company and Exelon Generation Company LLC (collectively, "ComEd") as a result of the Company's acquisition of EME. Pursuant to a settlement agreement dated as of May 29, 2019, the Company paid $26 million to ComEd during the second quarter of 2019, which was previously accrued. In addition, ComEd released all claims that were or could have been asserted in its claims in the EME bankruptcy case and certain of the Company's subsidiaries released all permissive and compulsory counter claims they could have asserted in response to the ComEd claims.

Washington-St. Tammany and Claiborne Electric Cooperative v. LaGen — On June 28, 2017, plaintiffs Washington-St. Tammany Electric Cooperative, Inc. and Claiborne Electric Cooperative, Inc. filed a lawsuit against Louisiana Generating, L.L.C., or LaGen, in the United States District Court for the Middle District of Louisiana. The plaintiffs claim breach of contract against LaGen for allegedly improperly charging the plaintiffs for costs related to the installation and maintenance of certain pollution control technology. Plaintiffs seek damages for the alleged improper charges and a declaration as to which charges are proper under the contract. In February 2020, the court dismissed this lawsuit without prejudice for lack of subject matter jurisdiction. On February 4, 2019, NRG sold the South Central Portfolio, including the entities subject to this litigation. However, NRG has agreed to indemnify the purchaser for certain losses suffered in connection therewith.

Sierra club et al. v. Midwest Generation LLC — In 2012, several environmental groups filed a complaint against Midwest Generation with the Illinois Pollution Control Board ("IPCB") alleging violations of environmental law resulting in groundwater contamination. In June 2019, the IPCB found that Midwest Generation violated the law because it had improperly handled coal ash at four facilities in Illinois and caused or allowed coal ash constituents to impact groundwater. On September 9, 2019, Midwest Generation filed a Motion to Reconsider numerous issues, which the court granted in part and denied in part on February 6, 2020. The IPCB will hold hearings to determine the appropriate relief. Midwest Generation has been working with the Illinois EPA to address the groundwater issues since 2010.

XOOM Energy Litigation — XOOM is a defendant in two purported class action lawsuits pending in Maryland and New York. The plaintiffs generally claim that they did not receive the savings they were promised in their natural gas and electricity bills. The parties in the Maryland lawsuit are briefing summary judgment and class certification. In the New York case, XOOM filed a motion to dismiss, which the court granted on September 21, 2018, later entering judgment in XOOM's favor on September 24, 2018. The plaintiffs in the New York case appealed to the U.S. Court of Appeals for the Second Circuit. On July 26, 2019, the Second Circuit reversed the judgment of the district court and remanded to the district court with instructions that plaintiffs be permitted to proceed on their proposed amended complaint. This matter was known and accrued for at the time of the acquisition.

Note 24 — *Regulatory Matters*

NRG operates in a highly regulated industry and is subject to regulation by various federal and state agencies. As such, NRG is affected by regulatory developments at both the federal and state levels and in the regions in which NRG operates. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO and RTO markets in which NRG participates. These power markets are subject to ongoing legislative and regulatory changes that may impact NRG's wholesale and retail businesses.

In addition to the regulatory proceedings noted below, NRG and its subsidiaries are parties to other regulatory proceedings arising in the ordinary course of business or have other regulatory exposure. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect NRG's consolidated financial position, results of operations, or cash flows.

California Station Power — As the result of unfavorable final and non-appealable litigation, the Company accrued a liability associated with consumption of station power at the Company's Encina power plant facility in California after August 30, 2010. The Company has established an appropriate accrual pending potential regulatory action by SDG&E regarding the Company's Encina facility.

South Central — On August 4, 2016, NRG received a document hold notice from FERC regarding conduct in the MISO and PJM markets. It required NRG to retain communications related to multiple generating units in the South Central region. Since sending the notice, FERC has been investigating potential violations of MISO rules involving bidding for the Big Cajun 2 facility, as well as other aspects of NRG’s operations in MISO. FERC has the authority to require disgorgement of profits and to impose penalties and NRG retains any liability following the sale of the South Central Portfolio. We expect a preliminary finding from FERC in 2020.

ISO-NE — On February 5, 2019, FERC has informed the Company that it has made a preliminary finding that the Company violated FERC's market behavior rules in connection with offers made into the ISO-NE Forward Capacity Auction in 2016. On April 26, 2019, NRG responded to the preliminary findings. The Company understands that FERC is concerned that the Company was inaccurate in its communications with the Market Monitor regarding the costs and risks associated with operating certain units in the forward timeframe. NRG withdrew the bids prior to the 2016 auction in the normal course of our commercial business decision making.

Note 25 — *Environmental Matters*

NRG is subject to a wide range of environmental laws in the development, construction, ownership and operation of power plants. These laws generally require that governmental permits and approvals be obtained before construction and during operation of power plants. NRG is also subject to laws regarding the protection of wildlife. The electric generation industry has been facing requirements regarding GHGs, combustion byproducts, water discharge and use, and threatened and endangered species that have been put in place in recent years. However, under the current U.S. presidential administration, some of these rules are being reconsidered and reviewed. In general, future laws are expected to require the addition of emissions controls or other environmental controls or to impose certain restrictions on the operations of the Company's facilities, which could have a material effect on the Company's consolidated financial position, results of operations, or cash flows. Federal and state environmental laws generally have become more stringent over time, although this trend could slow or pause in the near term with respect to federal laws under the current U.S. presidential administration.

Air

On July 8, 2019, the EPA promulgated the Affordable Clean Energy (ACE) rule, which rescinded the Clean Power Plan (CPP), which sought to broadly regulate CO_2 emissions from the power sector. The ACE rule requires states that have coal-fired EGUs to develop plans to seek heat rate improvements from coal-fired EGUs. Numerous parties have challenged the ACE rule in the D.C. Circuit and numerous parties have filed petitions for reconsideration with the EPA.

Water

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 (FGD), fly ash, bottom ash, and flue gas mercury control. On September 18, 2017, the EPA promulgated a final rule that, among other things, 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. On April 12, 2019, the United States Court of Appeals for the Fifth Circuit addressed challenges to the rule brought by several environmental groups related to legacy wastewaters and coal ash leachate and remanded portions of the rule to the EPA. On November 22, 2019, the EPA proposed amending the 2015 ELG rule by: (x) decreasing the stringency of the selenuim limit (but increasing the stringency of the nitrate and mercury limits) for FGD wastewater; (y) relaxing the zero-discharge requirement for bottom ash transport water; and (z) changing several deadlines. 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 EPA finalizes revisions to the rule.

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 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. On August 14, 2019, the EPA proposed targeted changes to the April 2015 Rule including changes to address the August 2018 D.C. Circuit decision. On December 2, 2019, the EPA released for comment "Closure Part A Proposal" to revise the CCR Rule to address the D.C. Circuit's 2018 decision regarding the adequacy of clay-lined impoundments, obligations to close all unlined impoundments and related deadlines. On February 20, 2020, the EPA proposed the framework for developing and implementing a federal permit program for states that are not approved to administer the CCR rule. We anticipate that the EPA will promulgate new regulations to address these and other issues as it reconsiders other aspects of the existing rule. The Company will determine estimates of the cost of compliance after the rule is revised.

Note 26 — *Cash Flow Information*

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

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Interest paid, net of amount capitalized	$ 372	$ 436	$ 543
Income taxes paid, net of refunds	8	9	9
Non-cash investing activities:			
Additions to fixed assets for accrued capital expenditures	1	20	19

Note 27 — *Guarantees*

NRG and its subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of the Company's business activities. Examples of these contracts include asset purchases and sale agreements, commodity sale and purchase agreements, retail contracts, joint venture agreements, EPC agreements, operation and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. The Company is obligated with respect to customer deposits associated with the Company's retail businesses. In some cases, NRG's maximum potential liability cannot be estimated, since the underlying agreements contain no limits on potential liability.

The following table summarizes the maximum potential exposures that can be estimated for NRG's guarantees, indemnities, and other contingent liabilities by maturity:

(In millions)	By Remaining Maturity at December 31, 2019					
Guarantees	**Under 1 Year**	**1-3 Years**	**3-5 Years**	**Over 5 Years**	**Total**	**2018 Total**
Letters of credit and surety bonds[(a)]	$ 878	$ 115	$ 31	$ —	$ 1,024	$ 1,253
Asset sales guarantee obligations	4	490	—	204	698	793
Other guarantees	77	5	—	206	288	721
Total guarantees	$ 959	$ 610	$ 31	$ 410	$ 2,010	$ 2,767

(a) December 31, 2019 includes $14 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

Letters of credit and surety bonds — As of December 31, 2019, NRG and its consolidated subsidiaries were contingently obligated for a total of $1.0 billion under letters of credit and surety bonds. Most of these letters of credit and surety bonds are issued in support of the Company's obligations to perform under commodity agreements and obligations associated with future closure and maintenance of ash sites, as well as for financing or other arrangements. A majority of these letters of credit and surety bonds expire within one year of issuance, and it is typical for the Company to renew them on similar terms.

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

Asset sales — The purchase and sale agreements which govern NRG's asset or share investments and divestitures customarily contain guarantees and indemnifications of the transaction to third parties. The contracts indemnify the parties for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party, or as a result of a change in tax laws. These obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or estimate at the time of the transaction. In several cases, the contract limits the liability of the indemnifier. NRG has no reason to believe that the Company currently has any material liability relating to such routine indemnification obligations, except as described in Note 4, *Acquisitions, Discontinued Operations and Dispositions.*

Other guarantees — NRG has issued other guarantees of obligations including payments under certain agreements with respect to certain of its unconsolidated subsidiaries, payment or performance by fuel providers and payment or reimbursement of credit support and deposits. The Company does not believe that it will be required to perform under these guarantees.

Other indemnities — Other indemnifications NRG has provided cover operational, tax, litigation and breaches of representations, warranties and covenants. NRG has also indemnified, on a routine basis in the ordinary course of business, consultants or other vendors who have provided services to the Company. NRG's maximum potential exposure under these indemnifications can range from a specified dollar amount to an indeterminate amount, depending on the nature of the transaction. Total maximum potential exposure under these indemnifications is not estimable due to uncertainty as to whether claims will be made or how they will be resolved. NRG does not have any reason to believe that the Company will be required to make any material payments under these indemnity provisions.

Because many of the guarantees and indemnities NRG issues to third parties and affiliates do not limit the amount or duration of its obligations to perform under them, there exists a risk that the Company may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit the Company's liability exposure, it may not be able to estimate what the Company's liability would be, until a claim is made for payment or performance, due to the contingent nature of these contracts.

Note 28 — *Jointly Owned Plants*

Certain NRG subsidiaries own undivided interests in jointly-owned plants, as described below. These plants are maintained and operated pursuant to their joint ownership participation and operating agreements. NRG is responsible for its subsidiaries' share of operating costs and direct expenses and includes its proportionate share of the facilities and related revenues and direct expenses in these jointly-owned plants in the corresponding balance sheet and income statement captions of the Company's consolidated financial statements.

The following table summarizes NRG's proportionate ownership interest in the Company's jointly-owned facilities:

(In millions unless otherwise stated)

As of December 31, 2019	**Ownership Interest**	**Property, Plant & Equipment**	**Accumulated Depreciation**	**Construction in Progress**
South Texas Project Units 1 and 2, Bay City, TX	44.00 %	$ 413	$ (206)	$ 8
Cedar Bayou Unit 4, Baytown, TX	50.00 %	218	(93)	7

Note 29 — *Unaudited Quarterly Financial Data*

Refer to Note 4, *Acquisitions, Discontinued Operations and Dispositions*, Note 11, *Asset Impairments*, *and* Note 20, *Income Taxes*, for a description of the effect of unusual or infrequently occurring events during the quarterly periods. Summarized unaudited quarterly financial data is as follows:

	Quarter Ended			
	2019			
(In millions, except per share data)	**December 31**	**September 30**	**June 30**	**March 31**
Operating revenues	$ 2,195	$ 2,996	$ 2,465	$ 2,165
Operating income	209	540	320	221
Net income from continuing operations	3,463	374	189	94
(Loss)/income from discontinued operations	(78)	(2)	13	388
Net income	3,385	372	202	482
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	2	—	1	—
Income available to Common Stockholders	$ 3,383	$ 372	$ 201	$ 482
Weighted average number of common shares outstanding — basic	251	254	265	278
(Loss)/income from discontinued operations per weighted average common share — basic	$ (0.31)	$ (0.01)	$ 0.05	$ 1.39
Net Income per weighted average common share — basic	$ 13.48	$ 1.46	$ 0.76	$ 1.73
Weighted average number of common shares outstanding — diluted	253	256	267	280
(Loss)/income from discontinued operations per weighted average common share — diluted	$ (0.31)	$ (0.01)	$ 0.05	$ 1.38
Net income per weighted average common share — diluted	$ 13.37	$ 1.45	$ 0.75	$ 1.72

(In millions, except per share data)	Quarter Ended 2018 December 31		September 30		June 30		March 31	
Operating revenues	$	1,992	$	2,960	$	2,461	$	2,065
Operating income		49		398		174		361
Net (loss)/income from continuing operations		(93)		287		27		238
Income/(loss) from discontinued operations		80		(336)		69		(5)
Net (loss)/income		(13)		(49)		96		233
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests		(2)		23		24		(46)
(Loss)/income available to Common Stockholders	$	(11)	$	(72)	$	72	$	279
Weighted average number of common shares outstanding — basic		289		299		310		318
Income/(loss) from discontinued operations per weighted average common share — basic	$	0.28	$	(1.12)	$	0.22	$	(0.02)
Net (loss)/income per weighted average common share — basic	$	(0.04)	$	(0.24)	$	0.23	$	0.88
Weighted average number of common shares outstanding — diluted		289		299		314		322
Income/(loss) from discontinued operations per weighted average common share — diluted	$	0.28	$	(1.12)	$	0.22	$	(0.02)
Net (loss)/income per weighted average common share — diluted	$	(0.04)	$	(0.24)	$	0.23	$	0.87

Note 30 — *Condensed Consolidating Financial Information*

As of December 31, 2019, the Company had outstanding $4.4 billion of Senior Notes due 2026 to 2048 and outstanding $1.1 billion of Senior Secured First Lien Notes due from 2024 to 2029, as shown in Note 13, *Debt and Finance Leases.* These Senior Notes and Senior Secured First Lien Notes are guaranteed by certain of NRG's current and future 100% owned domestic subsidiaries, or guarantor subsidiaries. These guarantees are both joint and several. The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes and Senior Secured First Lien Notes as of December 31, 2019:

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

NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company's ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG's ability to receive funds from its subsidiaries. There are no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to NRG. In addition, there may be restrictions for certain non-guarantor subsidiaries.

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

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

In addition, the condensed parent company financial statements are provided in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of NRG Energy, Inc.'s subsidiaries exceed 25 percent of the consolidated net assets of NRG Energy, Inc. These statements should be read in conjunction with the consolidated statements and notes thereto of NRG Energy, Inc. For a discussion of NRG Energy, Inc.'s long-term debt, see Note 13, *Debt and Finance Leases*, to the consolidated financial statements. For a discussion of NRG Energy, Inc.'s contingencies, see Note 23, *Commitments and Contingencies*, to the consolidated financial statements. For a discussion of NRG Energy, Inc.'s guarantees, see Note 27, *Guarantees*, to the consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the Year Ended December 31, 2019

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 8,041	$ 1,791	$ —	$ (11)	$ 9,821
Operating Costs and Expenses					
Cost of operations	5,936	1,351	27	(11)	7,303
Depreciation and amortization	212	130	31	—	373
Impairment losses	1	4	—	—	5
Selling, general and administrative	466	83	278	—	827
Reorganization costs	—	—	23	—	23
Development costs	—	—	7	—	7
Total operating costs and expenses	6,615	1,568	366	(11)	8,538
Gain on sale of assets	1	—	6	—	7
Operating Income/(Loss)	1,427	223	(360)	—	1,290
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	48	—	1,562	(1,610)	—
Equity in earnings of unconsolidated affiliates	—	2	—	—	2
Impairment losses on investments	—	(101)	(7)	—	(108)
Other income, net	23	12	31	—	66
Loss on debt extinguishment, net	—	(3)	(48)	—	(51)
Interest expense	(14)	(14)	(385)	—	(413)
Total other income/(expense)	57	(104)	1,153	(1,610)	(504)
Income from Continuing Operations Before Income Taxes	1,484	119	793	(1,610)	786
Income tax expense/(benefit)	—	4	(3,338)	—	(3,334)
Income from Continuing Operations	1,484	115	4,131	(1,610)	4,120
Income from discontinued operations, net of income tax	9	5	307	—	321
Net Income	1,493	120	4,438	(1,610)	4,441
Less: Net income attributable to redeemable noncontrolling interests	—	3	—	—	3
Net Income Attributable to NRG Energy, Inc.	$ 1,493	$ 117	$ 4,438	$ (1,610)	$ 4,438

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

For the Year Ended December 31, 2019

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Net Income	$ 1,493	$ 120	$ 4,438	$ (1,610)	$ 4,441
Other Comprehensive Loss, net of tax					
Foreign currency translation adjustments, net	—	(1)	(1)	1	(1)
Available-for-sale securities, net	—	—	(19)	—	(19)
Defined benefit plan, net	(17)	—	(78)	17	(78)
Other comprehensive loss	(17)	(1)	(98)	18	(98)
Comprehensive Income	1,476	119	4,340	(1,592)	4,343
Less: Comprehensive income attributable to redeemable noncontrolling interests	—	3	—	—	3
Comprehensive Income Attributable to NRG Energy, Inc.	$ 1,476	$ 116	$ 4,340	$ (1,592)	$ 4,340

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEETS

December 31, 2019

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ —	$ 20	$ 325	$ —	$ 345
Funds deposited by counterparties	32	—	—	—	32
Restricted cash	5	1	2	—	8
Accounts receivable, net	1,293	239	233	(740)	1,025
Inventory	272	111	—	—	383
Derivative instruments	856	45	—	(41)	860
Cash collateral posted in support of energy risk management activities	182	8	—	—	190
Prepayments and other current assets	170	8	67	—	245
Total current assets	2,810	432	627	(781)	3,088
Property, plant and equipment, net	1,483	952	158	—	2,593
Other Assets					
Investment in subsidiaries	710	—	4,785	(5,495)	—
Equity investments in affiliates	—	388	—	—	388
Operating lease right-of-use assets, net	81	261	122	—	464
Goodwill	359	220	—	—	579
Intangible assets, net	375	414	—	—	789
Nuclear decommissioning trust fund	794	—	—	—	794
Derivative instruments	308	15	—	(13)	310
Deferred income taxes	421	(19)	2,884	—	3,286
Other non-current assets	145	30	65	—	240
Total other assets	3,193	1,309	7,856	(5,508)	6,850
Total Assets	$ 7,486	$ 2,693	$ 8,641	$ (6,289)	$ 12,531
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ —	$ 5	$ 83	$ —	$ 88
Current portion of operating lease liabilities	20	32	21	—	73
Accounts payable	918	141	403	(740)	722
Derivative instruments	797	25	—	(41)	781
Cash collateral received in support of energy risk management activities	32	—	—	—	32
Accrued expenses and other current liabilities	280	44	339	—	663
Total current liabilities	2,047	247	846	(781)	2,359
Other Liabilities					
Long-term debt	302	28	5,473	—	5,803
Non-current operating lease liabilities	64	301	118	—	483
Nuclear decommissioning reserve	298	—	—	—	298
Nuclear decommissioning trust liability	487	—	—	—	487
Derivative instruments	334	1	—	(13)	322
Deferred income taxes	—	17	—	—	17
Other non-current liabilities	399	153	532	—	1,084
Total other liabilities	1,884	500	6,123	(13)	8,494
Total Liabilities	3,931	747	6,969	(794)	10,853
Redeemable noncontrolling interest in subsidiaries	—	20	—	—	20
Stockholders' Equity	3,555	1,926	1,672	(5,495)	1,658
Total Liabilities and Stockholders' Equity	$ 7,486	$ 2,693	$ 8,641	$ (6,289)	$ 12,531

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2019

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 1,493	$ 120	$ 4,438	$ (1,610)	$ 4,441
Income from discontinued operations	9	5	307	—	321
Net income from continuing operations	1,484	115	4,131	(1,610)	4,120
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(48)	14	(1,562)	1,610	14
Depreciation and amortization	212	130	31	—	373
Accretion of asset retirement obligations	43	8	—	—	51
Provision for bad debts	78	17	—	—	95
Amortization of nuclear fuel	52	—	—	—	52
Amortization of financing costs and debt discount/premiums	—	—	26	—	26
Adjustment for debt extinguishment	—	3	48	—	51
Amortization of emission allowances	24	14	—	—	38
Amortization of unearned equity compensation	—	—	20	—	20
Net gain on sale and disposal of assets	(20)	—	(3)	—	(23)
Impairment losses	1	105	7	—	113
Changes in derivative instruments	20	(24)	38	—	34
Changes in deferred income taxes and liability for uncertain tax benefits	(525)	(168)	(2,660)	—	(3,353)
Changes in collateral deposits in support of energy risk management activities	101	4	—	—	105
Changes in nuclear decommissioning trust liability	37	—	—	—	37
Changes in other working capital	(220)	(118)	(10)	—	(348)
Cash provided by continuing operations	1,239	100	66	—	1,405
Cash provided/(used) by discontinued operations	17	(9)	—	—	8
Net Cash Provided by Operating Activities	1,256	91	66	—	1,413
Cash Flows from Investing Activities					
Intercompany dividends	—	—	2,513	(2,513)	—
Payments for acquisitions of businesses	(355)	—	—	—	(355)
Capital expenditures	(164)	(27)	(37)	—	(228)
Net proceeds from sale of emission allowances	11	—	—	—	11
Investments in nuclear decommissioning trust fund securities	(416)	—	—	—	(416)
Proceeds from sales of nuclear decommissioning trust fund securities	381	—	—	—	381
Proceeds from sale of assets, net of cash disposed and sale of discontinued operations, net of fees	1	400	893	—	1,294
Changes in investments in unconsolidated affiliates	—	(91)	—	—	(91)
Net contributions to discontinued operations	—	(44)	—	—	(44)
Other	—	—	6	—	6
Cash (used)/provided by continuing operations	(542)	238	3,375	(2,513)	558
Cash used by discontinued operations	—	(2)	—	—	(2)
Net Cash (Used)/Provided by Investing Activities	(542)	236	3,375	(2,513)	556
Cash Flows from Financing Activities					
Intercompany dividends and transfers	(751)	(214)	(1,548)	2,513	—
Payments of dividends to common stockholders	—	—	(32)	—	(32)
Payments for share repurchase activity	—	—	(1,440)	—	(1,440)
Payments for debt extinguishment costs	—	—	(26)	—	(26)
Net distributions to redeemable noncontrolling interests from subsidiaries	—	(2)	—	—	(2)
Proceeds from issuance of common stock	—	—	3	—	3
Proceeds from issuance of long-term debt	—	—	1,916	—	1,916
Payments of debt issuance costs	—	—	(35)	—	(35)
Payments for short and long-term debt	—	(139)	(2,432)	—	(2,571)
Other	(4)	—	—	—	(4)
Cash used by continuing operations	(755)	(355)	(3,594)	2,513	(2,191)
Cash provided by discontinued operations	—	43	—	—	43
Net Cash Used by Financing Activities	(755)	(312)	(3,594)	2,513	(2,148)
Change in cash from discontinued operations	17	32	—	—	49
Net Decrease in Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties	(58)	(17)	(153)	—	(228)
Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties at Beginning of Period	95	38	480	—	613
Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties at End of Period	$ 37	$ 21	$ 327	$ —	$ 385

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the Year Ended December 31, 2018

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations [(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 8,119	$ 1,385	$ —	$ (26)	$ 9,478
Operating Costs and Expenses					
Cost of operations	6,147	959	28	(26)	7,108
Depreciation and amortization	238	150	33	—	421
Impairment losses	6	93	—	—	99
Selling, general and administrative	462	63	348	(74)	799
Reorganization costs	4	—	86	—	90
Development costs	—	1	11	(1)	11
Total operating costs and expenses	6,857	1,266	506	(101)	8,528
Gain on sale of assets	4	28	—	—	32
Operating Income/(Loss)	1,266	147	(506)	75	982
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	23	—	1,291	(1,314)	—
Equity in earnings/(losses) of unconsolidated affiliates	—	10	(1)	—	9
Impairment losses on investments	—	(15)	—	—	(15)
Other income/(expense), net	32	(13)	(1)	—	18
Loss on debt extinguishment, net	—	—	(44)	—	(44)
Interest expense	(14)	(49)	(420)	—	(483)
Total other income/(expense)	41	(67)	825	(1,314)	(515)
Income from Continuing Operations Before Income Taxes	1,307	80	319	(1,239)	467
Income tax expense/(benefit)	372	19	(384)	—	7
Income from Continuing Operations	935	61	703	(1,239)	460
Income/(loss) from discontinued operations, net of income tax	62	75	(329)	—	(192)
Net Income	997	136	374	(1,239)	268
Less: Net (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	—	(181)	106	75	—
Net Income Attributable to NRG Energy, Inc.	$ 997	$ 317	$ 268	$ (1,314)	$ 268

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

For the Year Ended December 31, 2018

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Net Income	$ 997	$ 136	$ 374	$ (1,239)	$ 268
Other Comprehensive Income/(Loss), net of tax					
Unrealized gain on derivatives, net	—	29	9	(15)	23
Foreign currency translation adjustments, net	(10)	(10)	(13)	22	(11)
Available-for-sale securities, net	—	—	1	—	1
Defined benefit plan, net	(9)	—	(35)	9	(35)
Other comprehensive (loss)/income	(19)	19	(38)	16	(22)
Comprehensive Income	978	155	336	(1,223)	246
Less: Comprehensive (loss)/income attributable to noncontrolling interests and redeemable noncontrolling interests	—	(166)	104	76	14
Comprehensive Income Attributable to NRG Energy, Inc.	$ 978	$ 321	$ 232	$ (1,299)	$ 232

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEETS

December 31, 2018

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 55	$ 28	$ 480	$ —	$ 563
Funds deposited by counterparties	33	—	—	—	33
Restricted cash	7	10	—	—	17
Accounts receivable. net	1,354	115	309	(754)	1,024
Inventory	278	134	—	—	412
Derivative instruments	779	50	16	(81)	764
Cash collateral posted in support of energy risk management activities	275	12	—	—	287
Prepayments and other current assets	180	32	90	—	302
Current assets - held-for-sale	—	1	—	—	1
Current assets - discontinued operations	177	20	—	—	197
Total current assets	3,138	402	895	(835)	3,600
Property, plant and equipment, net	1,938	957	153	—	3,048
Other Assets					
Investment in subsidiaries	446	—	4,707	(5,153)	—
Equity investments in affiliates	—	412	—	—	412
Goodwill	359	214	—	—	573
Intangible assets, net	422	169	—	—	591
Nuclear decommissioning trust fund	663	—	—	—	663
Derivative instruments	296	4	22	(5)	317
Deferred income taxes	6	(143)	183	—	46
Other non-current assets	133	71	97	(12)	289
Non-current assets - held-for-sale	—	77	—	—	77
Non-current assets - discontinued operations	405	607	—	—	1,012
Total other assets	2,730	1,411	5,009	(5,170)	3,980
Total Assets	$ 7,806	$ 2,770	$ 6,057	$ (6,005)	$ 10,628
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and finance leases	$ —	$ 55	$ 17	$ —	$ 72
Accounts payable	1,368	(185)	434	(754)	863
Derivative instruments	713	41	—	(81)	673
Cash collateral received in support of energy risk management activities	33	—	—	—	33
Accrued expenses and other current liabilities	291	36	353	—	680
Current liabilities - held-for-sale	—	5	—	—	5
Current liabilities - discontinued operations	24	48	—	—	72
Total current liabilities	2,429	—	804	(835)	2,398
Other Liabilities					
Long-term debt and finance leases	244	192	6,025	(12)	6,449
Nuclear decommissioning reserve	282	—	—	—	282
Nuclear decommissioning trust liability	371	—	—	—	371
Derivative instruments	306	3	—	(5)	304
Deferred income taxes	112	61	(108)	—	65
Other non-current liabilities	402	320	552	—	1,274
Non-current liabilities - held-for-sale	—	65	—	—	65
Non-current liabilities - discontinued operations	58	577	—	—	635
Total other liabilities	1,775	1,218	6,469	(17)	9,445
Total Liabilities	4,204	1,218	7,273	(852)	11,843
Redeemable noncontrolling interest in subsidiaries	—	19	—	—	19
Stockholders' Equity	3,602	1,533	(1,216)	(5,153)	(1,234)
Total Liabilities and Stockholders' Equity	$ 7,806	$ 2,770	$ 6,057	$ (6,005)	$ 10,628

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2018

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 997	$ 136	$ 374	$ (1,239)	$ 268
Income/(loss) from discontinued operations	62	75	(329)	—	(192)
Net income from continuing operations	935	61	703	(1,239)	460
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(23)	47	(1,231)	1,253	46
Depreciation and amortization	238	150	33	—	421
Accretion of asset retirement obligations	28	10	—	—	38
Provision for bad debts	79	6	—	—	85
Amortization of nuclear fuel	48	—	—	—	48
Amortization of financing costs and debt discount/premiums	—	6	23	—	29
Adjustment for debt extinguishment	—	—	44	—	44
Amortization of emission allowances and out-of-market contracts	36	9	—	—	45
Amortization of unearned equity compensation	—	—	25	—	25
Net (gain)/loss on sale and disposal of assets	(30)	(20)	1	—	(49)
Impairment losses	5	109	—	—	114
Changes in derivative instruments	25	15	11	(14)	37
Changes in deferred income taxes and liability for uncertain tax benefits	372	5	(372)	—	5
Changes in collateral deposits in support of energy risk management activities	(94)	(11)	—	—	(105)
Changes in nuclear decommissioning trust liability	60	—	—	—	60
GenOn settlement, net of insurance proceeds	—	—	(63)	—	(63)
Net loss on deconsolidation of Agua Caliente and Ivanpah projects	—	13	—	—	13
Changes in other working capital	(100)	(166)	16	—	(250)
Cash provided/(used) by continuing operations	1,579	234	(810)	—	1,003
Cash provided by discontinued operations	89	285	—	—	374
Net Cash Provided/(Used) by Operating Activities	1,668	519	(810)	—	1,377
Cash Flows from Investing Activities					
Intercompany dividends	—	—	2,006	(2,006)	—
Payments for acquisitions of businesses	(40)	(203)	—	—	(243)
Capital expenditures	(192)	(151)	(45)	—	(388)
Net proceeds from sale of emission allowances	19	—	—	—	19
Investments in nuclear decommissioning trust fund securities	(572)	—	—	—	(572)
Proceeds from sales of nuclear decommissioning trust fund securities	513	—	—	—	513
Proceeds from sale of assets, net of cash disposed and sale of discontinued operations, net of fees	14	8	1,542	—	1,564
Deconsolidation of Agua Caliente and Ivanpah projects	—	(268)	—	—	(268)
Changes in investments in unconsolidated affiliates	—	(39)	—	—	(39)
Net contributions to discontinued operations	—	(60)	—	—	(60)
Other	—	—	(6)	—	(6)
Cash (used)/provided by continuing operations	(258)	(713)	3,497	(2,006)	520
Cash used by discontinued operations	—	(725)	—	—	(725)
Net Cash (Used)/Provided by Investing Activities	(258)	(1,438)	3,497	(2,006)	(205)
Cash Flows from Financing Activities					
Intercompany dividends and transfers	(1,267)	86	(825)	2,006	—
Payments of dividends to common stockholders	—	—	(37)	—	(37)
Payments for treasury stock	—	—	(1,250)	—	(1,250)
Payments for debt extinguishment costs	—	—	(32)	—	(32)
Net distributions to noncontrolling interests from subsidiaries	—	(16)	—	—	(16)
Proceeds from issuance of common stock	—	—	21	—	21
Proceeds from issuance of long-term debt	—	163	937	—	1,100
Payments of debt issuance costs	—	—	(19)	—	(19)
Payments for short and long-term debt	—	(138)	(1,596)	—	(1,734)
Receivable from affiliate	—	—	(26)	—	(26)
Other	—	(4)	—	—	(4)
Cash (used)/provided by continuing operations	(1,267)	91	(2,827)	2,006	(1,997)
Cash provided by discontinued operations	—	471	—	—	471
Net Cash (Used)/Provided by Financing Activities	(1,267)	562	(2,827)	2,006	(1,526)
Effect of exchange rate changes on cash and cash equivalents	—	1	—	—	1
Change in cash from discontinued operations	89	31	—	—	120
Net Increase/(Decrease) in Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties	54	(387)	(140)	—	(473)
Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties at Beginning of Period	41	425	620	—	1,086
Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties at End of Period	$ 95	$ 38	$ 480	$ —	$ 613

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the Year Ended December 31, 2017

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations [(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 7,818	$ 1,304	$ —	$ (48)	$ 9,074
Operating Costs and Expenses					
Cost of operations	5,998	862	72	(46)	6,886
Depreciation and amortization	343	221	32	—	596
Impairment losses	1,346	188	—	—	1,534
Selling, general and administrative	410	64	364	(2)	836
Reorganization costs	6	—	38	—	44
Development costs	—	4	18	—	22
Total operating costs and expenses	8,103	1,339	524	(48)	9,918
Other income - affiliate	—	—	87	—	87
Gain on sale of assets	4	12	—	—	16
Operating Loss	(281)	(23)	(437)	—	(741)
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	18	—	28	(46)	—
Equity in losses of unconsolidated affiliates	—	(10)	(4)	—	(14)
Impairment losses on investments	—	(75)	(4)	—	(79)
Other income, net	9	14	28	—	51
Loss on debt extinguishment, net	—	—	(49)	—	(49)
Interest expense	(14)	(91)	(452)	—	(557)
Total other income/(expense)	13	(162)	(453)	(46)	(648)
Loss from Continuing Operations Before Income Taxes	(268)	(185)	(890)	(46)	(1,389)
Income tax (benefit)/expense	(598)	(62)	616	—	(44)
Income/(Loss) from Continuing Operations	330	(123)	(1,506)	(46)	(1,345)
Income/(loss) from discontinued operations, net of income tax	91	(420)	(663)	—	(992)
Net Income/(Loss)	421	(543)	(2,169)	(46)	(2,337)
Less: Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	—	(168)	(16)	—	(184)
Net Income/(Loss) Attributable to NRG Energy, Inc.	$ 421	$ (375)	$ (2,153)	$ (46)	$ (2,153)

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

For the Year Ended December 31, 2017

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Net Income/(Loss)	$ 421	$ (543)	$ (2,169)	$ (46)	$ (2,337)
Other Comprehensive Income/(Loss), net of tax					
Unrealized gain on derivatives, net	1	13	25	(26)	13
Foreign currency translation adjustments, net	6	7	—	(1)	12
Available-for-sale securities, net	—	—	(8)	—	(8)
Defined benefit plan, net	(13)	30	46	(17)	46
Other comprehensive (loss)/income	(6)	50	63	(44)	63
Comprehensive Income/(Loss)	415	(493)	(2,106)	(90)	(2,274)
Less: Comprehensive loss attributable to noncontrolling interest and redeemable noncontrolling interests	—	(103)	(16)	(60)	(179)
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	$ 415	$ (390)	$ (2,090)	$ (30)	$ (2,095)

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2017

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Cash Flows from Operating Activities					
Net income/(loss)	$ 421	$ (543)	$ (2,169)	$ (46)	$ (2,337)
Income/(loss) from discontinued operations	91	(420)	(663)	—	(992)
Net income/(loss) from continuing operations	330	(123)	(1,506)	(46)	(1,345)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities:					
Distributions and equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(18)	12	60	48	102
Depreciation and amortization	343	221	32	—	596
Accretion of asset retirement obligations	37	7	—	—	44
Provision for bad debts	56	—	12	—	68
Amortization of nuclear fuel	51	—	—	—	51
Amortization of financing costs and debt discount/premiums	—	13	16	—	29
Adjustment for debt extinguishment	—	—	49	—	49
Amortization of emission allowances and out-of-market contracts	42	12	—	—	54
Amortization of unearned equity compensation	—	—	35	—	35
Net loss/(gain) on sale and disposal of assets	2	(11)	—	—	(9)
Impairment losses	1,346	264	4	—	1,614
Changes in derivative instruments	(214)	50	(4)	(2)	(170)
Changes in deferred income taxes and liability for uncertain tax benefits	(300)	(9)	322	—	13
Changes in collateral deposits in support of energy risk management activities	(98)	18	—	—	(80)
Changes in nuclear decommissioning trust liability	11	—	—	—	11
Changes in other working capital	(15)	(396)	205	—	(206)
Cash provided/(used) by continuing operations	1,573	58	(775)	—	856
Cash provided by discontinued operations	116	638	—	—	754
Net Cash Provided/(Used) by Operating Activities	1,689	696	(775)	—	1,610
Cash Flows from Investing Activities					
Intercompany dividends	—	—	1,665	(1,665)	—
Payments for acquisitions of businesses	(14)	—	—	—	(14)
Capital expenditures	(180)	(43)	(31)	—	(254)
Net proceeds from sale of emission allowances	66	—	—	—	66
Investments in nuclear decommissioning trust fund securities	(512)	—	—	—	(512)
Proceeds from sales of nuclear decommissioning trust fund securities	501	—	—	—	501
Proceeds from sale of assets, net of cash disposed	33	54	343	—	430
Changes in investments in unconsolidated affiliates	—	(57)	—	—	(57)
Net distributions from discontinued operations	—	—	150	—	150
Other	18	12	—	—	30
Cash (used)/provided by continuing operations	(88)	(34)	2,127	(1,665)	340
Cash used by discontinued operations	(13)	(966)	—	—	(979)
Net Cash (Used)/Provided by Investing Activities	(101)	(1,000)	2,127	(1,665)	(639)
Cash Flows from Financing Activities					
Intercompany dividends and transfers	(1,447)	(4)	(214)	1,665	—
Payment of dividends to common stockholders	—	—	(38)	—	(38)
Payments for debt extinguishment costs	—	—	(42)	—	(42)
Net distributions to noncontrolling interests from subsidiaries	—	(30)	—	—	(30)
Payments for issuance of common stock	—	—	(2)	—	(2)
Proceeds from issuance of long-term debt	—	94	1,084	—	1,178
Payment of debt issuance costs	—	(2)	(16)	—	(18)
Payments for short and long-term debt	—	(183)	(1,701)	—	(1,884)
Receivable from affiliate	—	—	(125)	—	(125)
Other	—	(8)	—	—	(8)
Cash used by continuing operations	(1,447)	(133)	(1,054)	1,665	(969)
Cash used by discontinued operations	(109)	(60)	—	—	(169)
Net Cash Used by Financing Activities	(1,556)	(193)	(1,054)	1,665	(1,138)
Effect of exchange rate changes on cash and cash equivalents	—	(1)	—	—	(1)
Change in cash from discontinued operations	(6)	(388)	—	—	(394)
Net Increase/(Decrease) in Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties	38	(110)	298	—	226
Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties at Beginning of Period	3	535	322	—	860
Cash and Cash Equivalents, Restricted Cash, and Funds Deposited by Counterparties at End of Period	$ 41	$ 425	$ 620	$ —	$ 1,086

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

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2019, 2018, and 2017

(In millions)	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions		Balance at End of Period
Allowance for doubtful accounts, deducted from accounts receivable						
Year Ended December 31, 2019	$ 32	$ 95	$ —	$ (84)	(a)	$ 43
Year Ended December 31, 2018	28	83	—	(79)	(a)	32
Year Ended December 31, 2017	28	57	—	(57)	(a)	28
Income tax valuation allowance, deducted from deferred tax assets						
Year Ended December 31, 2019	$ 3,794	$ (3,543)	$ (9)	$ —		$ 242
Year Ended December 31, 2018	1,863	1,934	(128)	125	(b)	3,794
Year Ended December 31, 2017	4,116	(151)	(15)	(2,087)	(c)	1,863

(a) Represents principally net amounts charged as uncollectible
(b) Represents removal of NRG Yield, Inc. and its Renewables Platform due to their sale on August 31, 2018
(c) Represents deconsolidation of GenOn due to its petition for bankruptcy on June 14, 2017

Exhibit 99.2

Supplemental Quarterly Financial Data for the Year Ended December 31, 2019 (unaudited)

As part of perfecting the integrated model, in which the majority of the Company’s generation serves its retail customers, the Company began managing its operations based on the combined results of the retail and wholesale generation businesses with a geographical focus in 2020. As a result, the Company changed its business segments to Texas, East and West/Other beginning in the first quarter of 2020. The Company's updated segment structure reflects how management currently makes financial decisions and allocates resources. The unaudited financial information for the previously reported quarterly periods in the year ended December 31, 2019 has been retrospectively revised to reflect the current segment structure, as follows:

	For the Quarter Ended March 31, 2019				
(In millions)	**Texas**	**East**	**West/Other**	**Corporate/ Eliminations**	**Total**
Operating revenues					
Retail revenue	$ 1,253	$ 338	$ —	$ (2)	$ 1,589
Energy revenue	105	126	58	1	290
Capacity revenue	—	144	12	—	156
Mark-to-market for economic hedging activities	31	(15)	4	—	20
Other revenues	77	16	19	(2)	110
Total operating revenue	1,466	609	93	(3)	2,165
Cost of fuel	(149)	(66)	(36)	—	(251)
Purchased power	(327)	(191)	—	—	(518)
Other cost of sales	(486)	(75)	(11)	—	(572)
Mark-to-market for economic hedging activities	(5)	3	2	—	—
Contract and emission credit amortization	(5)	—	—	—	(5)
Gross margin	494	280	48	(3)	819
Other operating expenses	(301)	(152)	(39)	(7)	(499)
Depreciation and amortization	(40)	(26)	(11)	(8)	(85)
Impairment losses	—	—	—	—	—
Reorganization costs	(1)	—	—	(12)	(13)
Development costs	(1)	(1)	—	—	(2)
Gain on sale of assets	—	1	—	—	1
Operating income/(loss)	151	102	(2)	(30)	221
Equity in losses of unconsolidated affiliates	(3)	—	(18)	—	(21)
Other income, net	2	2	—	8	12
Interest expense	—	(5)	(3)	(106)	(114)
Income/(loss) from continuing operations before income taxes	150	99	(23)	(128)	98
Income tax expense	—	—	—	(4)	(4)
Net income/(loss) from continuing operations	150	99	(23)	(132)	94
Gain from discontinued operations, net of income tax	—	—	—	388	388
Net Income/(loss)	150	99	(23)	256	482
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	—
Net income/(loss) attributable to NRG Energy, Inc.	$ 150	$ 99	$ (23)	$ 256	$ 482

(In millions)	For the Quarter Ended June 30, 2019				
	Texas	East	West/Other	Corporate/ Eliminations	Total
Operating revenues					
Retail revenue	$ 1,433	$ 253	$ —	$ (1)	$ 1,685
Energy revenue	136	48	52	—	236
Capacity revenue	—	195	6	—	201
Mark-to-market for economic hedging activities	210	16	16	(1)	241
Other revenues	58	12	32	—	102
Total operating revenue	1,837	524	106	(2)	2,465
Cost of fuel	(200)	(34)	(32)	—	(266)
Purchased power	(301)	(108)	(2)	—	(411)
Other cost of sales	(500)	(90)	(6)	—	(596)
Mark-to-market for economic hedging activities	(216)	(2)	(3)	1	(220)
Contract and emission credit amortization	(6)	—	—	—	(6)
Gross margin	614	290	63	(1)	966
Other operating expenses	(310)	(196)	(47)	(4)	(557)
Depreciation and amortization	(40)	(30)	(7)	(8)	(85)
Impairment losses	(1)	—	—	—	(1)
Reorganization costs	(3)	—	—	1	(2)
Development costs	(1)	(1)	—	—	(2)
Gain on sale of assets	—	—	—	1	1
Operating income	259	63	9	(11)	320
Equity in (losses)/earnings of unconsolidated affiliates	(3)	—	3	—	—
Other income, net	3	1	9	7	20
Loss on debt extinguishment	—	—	—	(47)	(47)
Interest expense	—	(4)	(3)	(98)	(105)
Income from continuing operations before income taxes	259	60	18	(149)	188
Income tax benefit	—	—	—	1	1
Net income from continuing operations	259	60	18	(148)	189
Gain from discontinued operations, net of income tax	—	—	—	13	13
Net Income	259	60	18	(135)	202
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	1	—	1
Net income attributable to NRG Energy, Inc.	$ 259	$ 60	$ 17	$ (135)	$ 201

(In millions)	For the Quarter Ended September 30, 2019				
	Texas	East	West/Other	Corporate/ Eliminations	Total
Operating revenues					
Retail revenue	$ 2,132	$ 356	$ —	$ —	$ 2,488
Energy revenue	211	109	107	(1)	426
Capacity revenue	—	185	9	—	194
Mark-to-market for economic hedging activities	(213)	12	(9)	—	(210)
Other revenues	78	17	4	(1)	98
Total operating revenue	2,208	679	111	(2)	2,996
Cost of fuel	(227)	(79)	(55)	—	(361)
Purchased power	(573)	(160)	(6)	2	(737)
Other cost of sales	(739)	(101)	(10)	—	(850)
Mark-to-market for economic hedging activities	141	5		—	146
Contract and emission credit amortization	(5)	—	—	—	(5)
Gross margin	805	344	40	—	1,189
Other operating expenses	(319)	(189)	(42)	(6)	(556)
Depreciation and amortization	(45)	(31)	(8)	(7)	(91)
Impairment losses	—	—	—	—	—
Reorganization costs	(1)	—	—	—	(1)
Development costs	(1)	—	—	—	(1)
Gain on sale of assets	—	—	—	—	—
Operating income/(loss)	439	124	(10)	(13)	540
Equity in earnings of unconsolidated affiliates	1	—	28	—	29
Impairment losses on investments	(102)	—	—	(5)	(107)
Other income, net	10	1	—	6	17
Loss on debt extinguishment	—	—	—	—	—
Interest expense	—	(4)	(2)	(93)	(99)
Income from continuing operations before income taxes	348	121	16	(105)	380
Income tax expense	—	—	(1)	(5)	(6)
Net income from continuing operations	348	121	15	(110)	374
Loss from discontinued operations, net of income tax	—	—	—	(2)	(2)
Net Income	348	121	15	(112)	372
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	—
Net income attributable to NRG Energy, Inc.	$ 348	$ 121	$ 15	$ (112)	$ 372

	For the Quarter Ended December 31, 2019				
(In millions)	Texas	East	West/Other	Corporate/ Eliminations	Total
Operating revenues					
Retail revenue	$ 1,414	$ 357	$ —	$ —	$ 1,771
Energy revenue	77	39	101	—	217
Capacity revenue	—	140	9	—	149
Mark-to-market for economic hedging activities	19	(42)	5	—	(18)
Other revenues	48	13	15	—	76
Total operating revenue	1,558	507	130	—	2,195
Cost of fuel	(118)	(29)	(55)	—	(202)
Purchased power	(356)	(153)	(5)	(1)	(515)
Other cost of sales	(508)	(76)	(15)	—	(599)
Mark-to-market for economic hedging activities	23	(2)	—	—	21
Contract and emission credit amortization	(3)	—	—	—	(3)
Gross margin	596	247	55	(1)	897
Other operating expenses	(322)	(200)	(35)	(11)	(568)
Depreciation and amortization	(63)	(34)	(7)	(8)	(112)
Impairment losses	—	—	(4)	—	(4)
Reorganization costs	(1)	—	—	(6)	(7)
Development costs	—	(1)	(1)	—	(2)
Gain on sale of assets	—	—	—	5	5
Operating income	210	12	8	(21)	209
Equity in earnings/(losses) of unconsolidated affiliates	1	—	(7)	—	(6)
Impairment losses on investments	(1)	—	—	—	(1)
Other income, net	5	2	1	9	17
Loss on debt extinguishment	—	—	(3)	(1)	(4)
Interest expense	—	(5)	(2)	(88)	(95)
Income/(loss) from continuing operations before income taxes	215	9	(3)	(101)	120
Income tax (expense)/benefit	—	(2)	—	3,345	3,343
Net income/(loss) from continuing operations	215	7	(3)	3,244	3,463
Loss from discontinued operations, net of income tax	—	—	—	(78)	(78)
Net income/(loss)	215	7	(3)	3,166	3,385
Less: Net income attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	2	—	2
Net income/(loss) attributable to NRG Energy, Inc.	$ 215	$ 7	$ (5)	$ 3,166	$ 3,383