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

FORM 10-Q

x **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the Quarterly Period Ended: June 30, 2018

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission File Number: 001-15891

NRG Energy, Inc.

(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x **No** o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes x **No** o

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

Large accelerated filer x	**Accelerated filer** o	**Non-accelerated filer** o (Do not check if a smaller reporting company)	**Smaller reporting company** o	**Emerging growth company** o

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o **No** x

As of June 30, 2018, there were 303,429,305 shares of common stock outstanding, par value $0.01 per share.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q of NRG Energy, Inc., or NRG or the Company, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or Exchange Act. The words "believes," "projects," "anticipates," "plans," "expects," "intends," "estimates" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause NRG's actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Item 1A — *Risk Factors Related to NRG Energy, Inc.*, in Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2017, and the following:

- NRG's ability to achieve the expected benefits of its Transformation Plan;
- NRG's ability to engage in successful sales and divestitures as well as mergers and acquisitions activity;
- The potential adverse effects of the GenOn Entities' filings under Chapter 11 of the Bankruptcy Code and restructuring transactions on NRG's operations, management and employees and the risks associated with operating NRG's business during the restructuring process;
- Risks and uncertainties associated with the GenOn Entities' Chapter 11 Cases including the ability to achieve anticipated benefits therefrom;
- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;
- Volatile power supply costs and demand for power;
- Changes in law, including judicial decisions;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions (including wind and solar conditions), catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that NRG may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of NRG's risk management policies and procedures, and the ability of NRG's counterparties to satisfy their financial commitments;
- Counterparties' collateral demands and other factors affecting NRG's liquidity position and financial condition;
- NRG's ability to operate its businesses efficiently and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;
- NRG's ability to enter into contracts to sell power and procure fuel on acceptable terms and prices;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Government regulation, including changes in market rules, rates, tariffs and environmental laws;
- Price mitigation strategies and other market structures employed by ISOs or RTOs that result in a failure to adequately and fairly compensate NRG's generation units;
- NRG's ability to mitigate forced outage risk for units subject to capacity performance requirements in PJM, performance incentives in ISO-NE, and scarcity pricing in ERCOT;
- NRG's ability to borrow funds and access capital markets, as well as NRG's substantial indebtedness and the possibility that NRG may incur additional indebtedness going forward;
- Operating and financial restrictions placed on NRG and its subsidiaries that are contained in the indentures governing NRG's outstanding notes, in NRG's Senior Credit Facility, and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;
- Cyber terrorism and inadequate cybersecurity, or the occurrence of a catastrophic loss and the possibility that NRG may not have adequate insurance to cover losses resulting from such hazards or the inability of NRG's insurers to provide coverage;
- NRG's ability to develop and build new power generation facilities;
- NRG's ability to develop and innovate new products as retail and wholesale markets continue to change and evolve;
- NRG's ability to implement its strategy of finding ways to meet the challenges of climate change, clean air and protecting natural resources while taking advantage of business opportunities;
- NRG's ability to increase cash from operations through operational and commercial initiatives, corporate efficiencies, asset strategy, and a range of other programs throughout NRG to reduce costs or generate revenues;
- NRG's ability to sell assets to NRG Yield, Inc. and to close drop-down transactions;

- NRG's ability to achieve its strategy of regularly returning capital to stockholders;
- NRG's ability to obtain and maintain retail market share;
- NRG's ability to successfully evaluate investments and achieve intended financial results in new business and growth initiatives;
- NRG's ability to successfully integrate, realize cost savings and manage any acquired businesses; and
- NRG's ability to develop and maintain successful partnering relationships.

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

GLOSSARY OF TERMS

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

2017 Form 10-K	NRG’s Annual Report on Form 10-K for the year ended December 31, 2017
2023 Term Loan Facility	The Company's $1.9 billion term loan facility due 2023, a component of the Senior Credit Facility
Adjusted EBITDA	Adjusted earnings before interest, taxes, depreciation and amortization
ARO	Asset Retirement Obligation
ASC	The FASB Accounting Standards Codification, which the FASB established as the source of authoritative GAAP
ASU	Accounting Standards Updates - updates to the ASC
Average realized prices	Volume-weighted average power prices, net of average fuel costs and reflecting the impact of settled hedges
BACT	Best Available Control Technology
Bankruptcy Code	Chapter 11 of Title 11 the U.S. Bankruptcy Code
Bankruptcy Court	United States Bankruptcy Court for the Southern District of Texas, Houston Division
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
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CASPR	Competitive Auctions with Sponsored Resources
CDD	Cooling Degree Day
CDWR	California Department of Water Resources
CEC	California Energy Commission
CenterPoint	CenterPoint Energy Houston Electric, LLC
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
Cleco	Cleco Energy LLC
COD	Commercial Operation Date
ComEd	Commonwealth Edison
Company	NRG Energy, Inc.
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CVSR	California Valley Solar Ranch
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DGPV Holdco 1	NRG DGPV Holdco 1 LLC
DGPV Holdco 2	NRG DGPV Holdco 2 LLC
DGPV Holdco 3	NRG DGPV Holdco 3 LLC
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
Economic gross margin	Sum of energy revenue, capacity revenue, retail revenue and other revenue, less cost of fuels and other cost of sales
El Segundo Energy Center	NRG West Holdings LLC, the subsidiary of Natural Gas Repowering LLC, which owns the El Segundo Energy Center project
EME	Edison Mission Energy
Energy Plus Holdings	Energy Plus Holdings LLC
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPSA	The Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESP	Electrostatic Precipitator
ESPP	NRG Energy, Inc. Amended and Restated Employee Stock Purchase Plan
ESPS	Existing Source Performance Standards
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Fresh Start	Reporting requirements as defined by ASC-852, *Reorganizations*
FTRs	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the U.S.
GenConn	GenConn Energy LLC
GenOn	GenOn Energy, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC
GenOn Americas Generation Senior Notes	GenOn Americas Generation's $395 million outstanding unsecured senior notes consisting of $208 million of 8.5% senior notes due 2021 and $187 million of 9.125% senior notes due 2031
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
GenOn Senior Notes	GenOn's $1.8 billion outstanding unsecured senior notes consisting of $691 million of 7.875% senior notes due 2017, $649 million of 9.5% senior notes due 2018, and $489 million of 9.875% senior notes due 2020
GenOn Settlement	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 Generation and GenOn, and certain of GenOn's direct and indirect subsidiaries
GHG	Greenhouse Gas
GIP	Global Infrastructure Partners
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

IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IPA	Illinois Power Agency
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
LTIPs	Collectively, the NRG LTIP and the NRG GenOn LTIP
Marsh Landing	NRG Marsh Landing, LLC (formerly known as GenOn Marsh Landing, LLC)
Mass Market	Residential and small commercial customers
MATS	Mercury and Air Toxics Standards promulgated by the EPA
MDth	Thousand Dekatherms
Midwest Generation	Midwest Generation, LLC
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Saleable megawatt hour net of internal/parasitic load megawatt-hour
MWt	Megawatts Thermal Equivalent
NAAQS	National Ambient Air Quality Standards
NEPGA	New England Power Generators Association
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
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
NOL	Net Operating Loss
NOV	Notice of Violation
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchase Normal Sale
NRC	U.S. Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NRG Yield	Reporting segment including the projects owned by NRG Yield, Inc.
NRG Yield 2019 Convertible Notes	$345 million aggregate principal amount of 3.50% Convertible Senior Notes due 2019 issued by NRG Yield, Inc.
NRG Yield 2020 Convertible Notes	$287.5 million aggregate principal amount of 3.25% Convertible Notes due 2020 issued by NRG Yield, Inc.
NRG Yield, Inc.	NRG Yield, Inc., the owner of 54.8% of the economic interests of NRG Yield LLC with a controlling interest, and issuer of publicly held shares of Class A and Class C common stock
NSR	New Source Review
Nuclear Decommissioning Trust Fund	NRG's nuclear decommissioning trust fund assets, which are for the Company's portion of the decommissioning of the STP, units 1 & 2
NYAG	State of New York Office of Attorney General
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange

NYSPSC	New York State Public Service Commission
OCI/OCL	Other Comprehensive Income/(Loss)
Peaking	Units expected to satisfy demand requirements during the periods of greatest or peak load on the system
PER	Peak Energy Rent
Petition Date	June 14, 2017
Pipeline	Projects that range from identified lead to shortlisted with an offtake, and represents a lower level of execution certainty.
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 2005
RCRA	Resource Conservation and Recovery Act of 1976
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
Restructuring Support Agreement	Restructuring Support and Lock-Up Agreement, dated as of June 12, 2017 and as amended on October 2, 2017, by and among GenOn Energy, Inc., GenOn Americas Generation, LLC, and subsidiaries signatory thereto, NRG Energy, Inc. and the noteholders signatory thereto
Retail	Reporting segment that includes NRG's residential and small commercial businesses which go to market as Reliant, NRG and other brands owned by NRG, as well as Business Solutions
Revolving Credit Facility	The Company’s $2.5 billion revolving credit facility, a component of the Senior Credit Facility. The revolving credit facility consists of $289 million of Tranche A Revolving Credit Facility, due 2018, and $2.2 billion of Tranche B Revolving Credit Facility, due 2021
RFO	Request for Offer
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
RPV Holdco	NRG RPV Holdco 1 LLC
RTO	Regional Transmission Organization
RTR	Renewable Technology Resource
SCE	Southern California Edison
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
Senior Notes	As of December 31, 2017, NRG’s $4.8 billion outstanding unsecured senior notes consisting of $992 million of 6.25% senior notes due 2022, $733 million of 6.25% senior notes due 2024, $1.0 billion of 7.25% senior notes due 2026, $1.25 billion of 6.625% senior notes due 2027, and $870 million of 5.75% senior notes due 2028.
Services Agreement	NRG provided GenOn with various management, personnel and other services, which include human resources, regulatory and public affairs, accounting, tax, legal, information systems, treasury, risk management, commercial operations, and asset management, as set forth in the services agreement with GenOn
SIFMA	Securities Industry and Financial Markets Association
SO_2	Sulfur Dioxide

South Central	NRG's South Central business, which owns and operates a 3,555-MW portfolio of generation assets consisting of 225-MW Bayou Cove, 430-MW Big Cajun-I, 1,461-MW Big Cajun-II, 1,263-MW Cottonwood and 176-MW Sterlington, and serves a customer base of cooperatives, municipalities and regional utilities under load contracts.
S&P	Standard & Poor's
TCPA	Telephone Consumer Protection Act
TSA	Transportation Services Agreement
TWCC	Texas Westmoreland Coal Co.
U.S.	United States of America
U.S. DOE	U.S. Department of Energy
Utility Scale Solar	Solar power projects, typically 20 MW or greater in size (on an alternating current basis), that are interconnected into the transmission or distribution grid to sell power at a wholesale level
VaR	Value at Risk
VCP	Voluntary Clean-Up Program
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council
WST	Washington-St. Tammany Electric Cooperative, Inc.
Yield Operating	NRG Yield Operating LLC

PART I — FINANCIAL INFORMATION

ITEM 1 — CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

(In millions, except for per share amounts)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Operating Revenues				
Total operating revenues	$ 2,922	$ 2,701	$ 5,343	$ 5,083
Operating Costs and Expenses				
Cost of operations	2,051	1,841	3,609	3,704
Depreciation and amortization	227	260	462	517
Impairment losses	74	63	74	63
Selling, general and administrative	211	221	402	481
Reorganization costs	23	—	43	—
Development costs	16	18	29	35
Total operating costs and expenses	2,602	2,403	4,619	4,800
Other income - affiliate	—	39	—	87
Gain on sale of assets	14	2	16	4
Operating Income	334	339	740	374
Other Income/(Expense)				
Equity in earnings/(losses) of unconsolidated affiliates	18	(3)	16	2
Other income/(expense), net	(20)	14	(23)	26
Loss on debt extinguishment, net	(1)	—	(3)	(2)
Interest expense	(202)	(247)	(369)	(471)
Total other expense	(205)	(236)	(379)	(445)
Income/(Loss) from Continuing Operations Before Income Taxes	129	103	361	(71)
Income tax expense/(benefit)	8	4	7	(1)
Income/(Loss) from Continuing Operations	121	99	354	(70)
Loss from discontinued operations, net of income tax	(25)	(741)	(25)	(775)
Net Income/(Loss)	96	(642)	329	(845)
Less: Net income/(loss) attributable to noncontrolling interest and redeemable noncontrolling interests	24	(16)	(22)	(55)
Net Income/(Loss) Attributable to NRG Energy, Inc.	$ 72	$ (626)	$ 351	$ (790)
Earnings/(Loss) per Share Attributable to NRG Energy, Inc. Common Stockholders				
Weighted average number of common shares outstanding — basic	310	316	314	316
Income/(loss) from continuing operations per weighted average common share — basic	$ 0.31	$ 0.36	$ 1.20	$ (0.05)
Income/(loss) from discontinued operations per weighted average common share — basic	$ (0.08)	$ (2.34)	$ (0.08)	$ (2.45)
Earnings/(Loss) per Weighted Average Common Share — Basic	$ 0.23	$ (1.98)	$ 1.12	$ (2.50)
Weighted average number of common shares outstanding — diluted	314	316	318	316
Income/(loss) from continuing operations per weighted average common share — diluted	$ 0.31	$ 0.36	$ 1.18	$ (0.05)
Income/(loss) from discontinued operations per weighted average common share — diluted	$ (0.08)	$ (2.34)	$ (0.08)	$ (2.45)
Earnings/(Loss) per Weighted Average Common Share — Diluted	$ 0.23	$ (1.98)	$ 1.10	$ (2.50)
Dividends Per Common Share	$ 0.03	$ 0.03	$ 0.06	$ 0.06

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Net income/(loss)	$ 96	$ (642)	$ 329	$ (845)
Other comprehensive income/(loss), net of tax				
Unrealized gain/(loss) on derivatives, net of income tax expense of $0, $0, $0, and $1	5	(5)	19	(1)
Foreign currency translation adjustments, net of income tax expense of $0, $0, $0, and $0	(4)	1	(6)	8
Available-for-sale securities, net of income tax expense of $0, $0, $0, and $0	1	1	1	1
Defined benefit plans, net of income tax expense of $0, $0, $0, and $0	(1)	27	(2)	27
Other comprehensive income	1	24	12	35
Comprehensive income/(loss)	97	(618)	341	(810)
Less: Comprehensive loss attributable to noncontrolling interest and redeemable noncontrolling interest	26	(17)	(12)	(56)
Comprehensive income/(loss) attributable to NRG Energy, Inc.	71	(601)	353	(754)
Comprehensive income/(loss) available for common stockholders	$ 71	$ (601)	$ 353	$ (754)

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except shares)	June 30, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$ 980	$ 991
Funds deposited by counterparties	71	37
Restricted cash	286	508
Accounts receivable, net	1,371	1,079
Inventory	485	532
Derivative instruments	851	626
Cash collateral paid in support of energy risk management activities	224	171
Accounts receivable - affiliate	57	95
Current assets - held for sale	100	115
Prepayments and other current assets	328	261
Total current assets	4,753	4,415
Property, plant and equipment, net	12,774	13,908
Other Assets		
Equity investments in affiliates	1,055	1,038
Notes receivable, less current portion	15	2
Goodwill	539	539
Intangible assets, net	1,860	1,746
Nuclear decommissioning trust fund	694	692
Derivative instruments	426	172
Deferred income taxes	126	134
Non-current assets held-for-sale	50	43
Other non-current assets	655	629
Total other assets	5,420	4,995
Total Assets	$ 22,947	$ 23,318
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 952	$ 688
Accounts payable	975	881
Accounts payable - affiliate	29	33
Derivative instruments	709	555
Cash collateral received in support of energy risk management activities	72	37
Current liabilities held-for-sale	74	72
Accrued expenses and other current liabilities	719	890
Accrued expenses and other current liabilities - affiliate	133	161
Total current liabilities	3,663	3,317
Other Liabilities		
Long-term debt and capital leases	14,821	15,716
Nuclear decommissioning reserve	274	269
Nuclear decommissioning trust liability	410	415
Deferred income taxes	17	21
Derivative instruments	285	197
Out-of-market contracts, net	195	207
Non-current liabilities held-for-sale	12	8
Other non-current liabilities	1,130	1,122
Total non-current liabilities	17,144	17,955
Total Liabilities	20,807	21,272
Redeemable noncontrolling interest in subsidiaries	69	78
Commitments and Contingencies		
Stockholders' Equity		
Common stock	4	4
Additional paid-in capital	8,481	8,376
Accumulated deficit	(5,920)	(6,268)
Less treasury stock, at cost — 116,267,484 and 101,580,045 shares, at June 30, 2018 and December 31, 2017, respectively	(2,871)	(2,386)

Accumulated other comprehensive loss		(60)		(72)
Noncontrolling interest		2,437		2,314
Total Stockholders' Equity		2,071		1,968
Total Liabilities and Stockholders' Equity	$	22,947	$	23,318

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six months ended June 30,	
(In millions)	**2018**	**2017**
Cash Flows from Operating Activities		
Net income/(loss)	$ 329	$ (845)
Loss from discontinued operations, net of income tax	(25)	(775)
Income/(loss) from continuing operations	354	(70)
Adjustments to reconcile net income to net cash provided/(used) by operating activities:		
Distributions and equity in earnings of unconsolidated affiliates	27	26
Depreciation, amortization and accretion	485	517
Provision for bad debts	31	18
Amortization of nuclear fuel	24	24
Amortization of financing costs and debt discount/premiums	27	29
Adjustment for debt extinguishment	3	—
Amortization of intangibles and out-of-market contracts	48	51
Amortization of unearned equity compensation	26	16
Impairment losses	89	63
Changes in deferred income taxes and liability for uncertain tax benefits	4	8
Changes in nuclear decommissioning trust liability	41	2
Changes in derivative instruments	(211)	7
Changes in collateral deposits in support of energy risk management activities	(18)	(189)
Gain on sale of emission allowances	(11)	11
Gain on sale of assets	(16)	(22)
Loss on deconsolidation of business	22	—
Changes in other working capital	(401)	(379)
Cash provided by continuing operations	524	112
Cash used by discontinued operations	—	(38)
Net Cash Provided by Operating Activities	524	74
Cash Flows from Investing Activities		
Acquisitions of businesses, net of cash acquired	(284)	(16)
Capital expenditures	(691)	(542)
Decrease in notes receivable	4	8
Purchases of emission allowances	(22)	(30)
Proceeds from sale of emission allowances	34	59
Investments in nuclear decommissioning trust fund securities	(346)	(279)
Proceeds from the sale of nuclear decommissioning trust fund securities	303	277
Proceeds from renewable energy grants and state rebates	—	8
Proceeds from sale of assets, net of cash disposed of	18	35
Deconsolidation of business	(160)	—
Changes in investments in unconsolidated affiliates	(2)	(30)
Other	—	18
Cash used by continuing operations	(1,146)	(492)
Cash used by discontinued operations	—	(53)
Net Cash Used by Investing Activities	(1,146)	(545)
Cash Flows from Financing Activities		
Payment of dividends to common and preferred stockholders	(19)	(19)
Payment for treasury stock	(500)	—
Net receipts from settlement of acquired derivatives that include financing elements	—	2
Proceeds from issuance of long-term debt	1,605	946
Payments for short and long-term debt	(848)	(530)
Increase in notes receivable from affiliate	—	(125)
Net contributions from noncontrolling interests in subsidiaries	222	14
Payment of debt issuance costs	(37)	(36)
Other - contingent consideration	—	(10)
Cash provided by continuing operations	423	242
Cash used by discontinued operations	—	(224)
Net Cash Provided by Financing Activities	423	18
Effect of exchange rate changes on cash and cash equivalents	—	(8)
Change in Cash from discontinued operations	—	(315)
Net Decrease in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash	(199)	(146)
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period	1,536	1,386
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period	$ 1,337	$ 1,240

See accompanying notes to condensed consolidated financial statements.

Note 1 — *Basis of Presentation*

General

NRG Energy, Inc., or NRG or the Company, is a customer-driven integrated power company built on a portfolio of leading retail electricity brands and diverse generation assets. NRG is continuously focused on serving the energy needs of end-use residential, commercial and industrial customers in competitive markets through multiple brands and channels. The Company:

- directly sells energy and innovative, sustainable products and services to retail customers under the names “NRG”, “Reliant” and other retail brand names owned by NRG;
- owns and operates approximately 30,000 MW of generation;
- engages in the trading of wholesale energy, capacity and related products; and
- transacts in and trades fuel and transportation services.

The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with the SEC's regulations for interim financial information and with the instructions to Form 10-Q. Accordingly, they do not include all of the information and notes required by generally accepted accounting principles for complete financial statements. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to the consolidated financial statements in the Company's 2017 Form 10-K. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim condensed consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly the Company's consolidated financial position as of June 30, 2018, and the results of operations, comprehensive income/(loss) and cash flows for the three and six months ended June 30, 2018 and 2017.

GenOn Chapter 11 Cases

On June 14, 2017, GenOn, along with GenOn Americas Generation and certain of their directly and indirectly-owned subsidiaries, or collectively the GenOn Entities, filed voluntary petitions for relief under Chapter 11, or the Chapter 11 Cases, of the U.S. Bankruptcy Code, in the U.S. Bankruptcy Court for the Southern District of Texas, Houston Division, or the Bankruptcy Court. GenOn Mid-Atlantic, as well as its consolidated subsidiaries, REMA and certain other subsidiaries, did not file for relief under Chapter 11.

As a result of the bankruptcy filings and beginning on June 14, 2017, GenOn and its subsidiaries were deconsolidated from NRG’s consolidated financial statements. NRG determined that this disposal of GenOn and its subsidiaries is a discontinued operation and, accordingly, the financial information for all historical periods has been recast to reflect GenOn as a discontinued operation.

Use of Estimates

The preparation of financial statements in conformity with GAAP 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.

Reclassifications

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

Note 2 — *Summary of Significant Accounting Policies*

Other Balance Sheet Information

The following table presents the allowance for doubtful accounts included in accounts receivable, net; accumulated depreciation included in property, plant and equipment, net; accumulated amortization included in intangible assets, net and accumulated amortization included in out-of-market contracts, net:

	June 30, 2018	December 31, 2017
	(In millions)	
Accounts receivable allowance for doubtful accounts	$ 28	$ 28
Property, plant and equipment accumulated depreciation	4,534	4,465
Intangible assets accumulated amortization	1,443	1,818
Out-of-market contracts accumulated amortization	370	358

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 sheet that sum to the total of the same such amounts shown in the statement of cash flows.

	June 30, 2018	December 31, 2017	June 30, 2017	December 31, 2016
	(In millions)			
Cash and cash equivalents	$ 980	$ 991	$ 752	$ 938
Funds deposited by counterparties	71	37	19	2
Restricted cash	286	508	469	446
Cash and cash equivalents, funds deposited by counterparties and restricted cash shown in the statement of cash flows	$ 1,337	$ 1,536	$ 1,240	$ 1,386

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 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.

Noncontrolling Interest

The following table reflects the changes in NRG's noncontrolling interest balance:

	(In millions)
Balance as of December 31, 2017	$ 2,314
Dividends paid to NRG Yield, Inc. public shareholders	(61)
Distributions to noncontrolling interest	(34)
Comprehensive income attributable to noncontrolling interest	12
Non-cash adjustments to noncontrolling interest	8
Contributions from noncontrolling interest	295
Sale of assets to NRG Yield, Inc.	(8)
Deconsolidation of Ivanpah[(a)]	(89)
Balance as of June 30, 2018	$ 2,437

(a) See Note 9, *Variable Interest Entities, or VIEs* for further information regarding the deconsolidation of Ivanpah effective April 2018.

Redeemable Noncontrolling Interest

The following table reflects the changes in the Company's redeemable noncontrolling interest balance:

		(In millions)
Balance as of December 31, 2017	$	78
Distributions to redeemable noncontrolling interest		(2)
Contributions from redeemable noncontrolling interest		26
Non-cash adjustments to redeemable noncontrolling interest		(9)
Comprehensive loss attributable to redeemable noncontrolling interest		(24)
Balance as of June 30, 2018	$	69

Revenue Recognition

Revenue from Contracts with Customers

On January 1, 2018, the Company adopted the guidance in ASC 606 using the modified retrospective method applied to contracts which were not completed as of the adoption date. The Company recognized the cumulative effect of initially applying the new standard as a credit to the opening balance of accumulated deficit, resulting in a decrease of approximately $16 million. The adjustment primarily related to costs incurred to obtain a contract with customers and customer incentives. Following the adoption of the new standard, the Company’s revenue recognition of its contracts with customers remains materially consistent with its historical practice. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The Company's policies with respect to its various revenue streams are detailed below. In general, the Company applies the invoicing practical expedient to recognize revenue for the revenue streams detailed below, except in circumstances where the invoiced amount does not represent the value transferred to the customer.

Retail Revenues

Gross revenues for energy sales and services to retail customers are recognized as the Company transfers the promised goods and services to the customer. For the majority of its electricity contracts, the Company’s performance obligation with the customer is satisfied over time and performance obligations for its electricity products are recognized as the customer takes possession of the product. The Company also allocates the contract consideration to distinct performance obligation in a contract for which the timing of the revenue recognized is different. Additionally, customer discounts and incentives reduce the contract consideration and are recognized over the term of the contract.

Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

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

Energy Revenue

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

Capacity Revenue

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

Capacity revenue contracts mainly consist of:

Capacity auctions — The Company's largest sources of capacity revenues are capacity auctions in PJM, ISO-NE, and NYISO. Both ISO-NE and PJM operate a pay-for-performance model where capacity payments are modified based on real-time performance, where NRG's actual revenues will be the combination of revenues based on the cleared auction MWs plus the net of any over- and under-performance of NRG's fleet. In addition, MISO has an annual auction, known as the Planning Resource Auction, or PRA. The Gulf Coast assets situated in the MISO market may participate in this auction. Estimated revenues for cleared auction MWs in the various capacity auctions are $578 million, $519 million, $410 million, $388 million and $168 million for fiscal years 2018, 2019, 2020, 2021 and 2022, respectively.

Resource adequacy and bilateral contracts — In California, there is a resource adequacy requirement that is primarily satisfied through bilateral contracts. Such bilateral contracts are typically short-term resource adequacy contracts. When bilateral contracting does not satisfy the resource adequacy need, such shortfalls can be addressed through procurement tools administered by the CAISO, including the capacity procurement mechanism or reliability must-run contracts. Demand payments from the current long-term contracts are tied to summer peak demand and provide a mechanism for recovering a portion of the costs associated with new or changed environmental laws or regulations. In Texas, capacity and contracted revenues are through bilateral contracts with load serving entities.

Long-term PPAs — Energy, capacity and where applicable, renewable attributes, from the majority of renewable energy assets and certain conventional energy plants is sold through long-term PPAs and tolling agreements to a single counterparty, which is often a utility or commercial customer. Many of these PPAs are accounted for as leases.

Renewable Energy Credits

As stated above, renewable energy credits are usually sold through long-term PPAs. 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 usage from the Company's emission bank to intangible assets held-for-sale for trading purposes. The Company records the sale of emission allowances on a net basis within operating revenue in the Company's consolidated statements of operations.

Disaggregated Revenues

The following table represents the Company's disaggregation of revenue from contracts with customers for the three and six months ended June 30, 2018, along with the reportable segment for each category:

	Three months ended June 30, 2018							
		Generation						
(In millions)	Retail	Gulf Coast	East/West	Subtotal	Renewables	NRG Yield	Eliminations	Total
Energy revenue[(a)(b)]	$ —	$ 508	$ 144	$ 652	$ 79	$ 192	$ (250)	$ 673
Capacity revenue[(a)(b)]	—	68	160	228	—	87	(2)	313
Retail revenue								
Mass customers	1,380	—	—	—	—	—	(1)	1,379
Business solutions customers	437	—	—	—	—	—	—	437
Total retail revenue	1,817	—	—	—	—	—	(1)	1,816
Mark-to-market for economic hedging activities[(c)]	—	289	(15)	274	5	—	(264)	15
Contract amortization	—	4	—	4	—	(18)	—	(14)
Other revenue[(a)(b)]	—	42	18	60	29	46	(16)	119
Total operating revenue	1,817	911	307	1,218	113	307	(533)	2,922
Less: Lease revenue	6	—	1	1	96	267	—	370
Less: Derivative revenue	—	898	(1)	897	5	—	(264)	638
Less: Contract amortization	—	4	—	4	—	(18)	—	(14)
Total revenue from contracts with customers	$ 1,811	$ 9	$ 307	$ 316	$ 12	$ 58	$ (269)	$ 1,928

(a) The following amounts of energy and capacity revenue relate to leases and are accounted for under ASC 840:

	Retail	Gulf Coast	East/West	Subtotal	Renewables	NRG Yield	Eliminations	Total
Energy revenue	$ —	$ —	$ —	$ —	$ 90	$ 182	$ —	$ 272
Capacity revenue	—	—	—	—	—	85	—	85
Other revenue	6	—	1	1	6	—	—	13

(b) The following amounts of energy and capacity revenue relate to derivative instruments and are accounted for under ASC 815.

	Retail	Gulf Coast	East/West	Subtotal	Renewables	NRG Yield	Eliminations	Total
Energy revenue	$ —	$ 610	$ (30)	$ 580	$ —	$ —	$ —	$ 580
Capacity revenue	—	—	39	39	—	—	—	39
Other revenue	—	(1)	5	4	—	—	—	4

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

	Six months ended June 30, 2018							
		Generation						
(In millions)	Retail	Gulf Coast	East/West	Subtotal	Renewables	NRG Yield	Eliminations	Total
Energy revenue[(a)(b)]	$ —	$ 879	$ 362	$ 1,241	$ 156	$ 306	$ (411)	$ 1,292
Capacity revenue[(a)(b)]	—	135	300	435	—	169	(3)	601
Retail revenue								
Mass customers	2,551	—	—	—	—	—	(2)	2,549
Business solutions customers	753	—	—	—	—	—	—	753
Total retail revenue	3,304	—	—	—	—	—	(2)	3,302
Mark-to-market for economic hedging activities[(c)]	(6)	(275)	(25)	(300)	(5)	—	220	(91)
Contract amortization	—	7	—	7	—	(35)	—	(28)
Other revenue[(a)(b)]	—	128	34	162	48	92	(35)	267
Total operating revenue	3,298	874	671	1,545	199	532	(231)	5,343
Less: Lease revenue	12	—	2	2	160	448	—	622
Less: Derivative revenue	(6)	710	79	789	(5)	—	220	998
Less: Contract amortization	—	7	—	7	—	(35)	—	(28)
Total revenue from contracts with customers	$ 3,292	$ 157	$ 590	$ 747	$ 44	$ 119	$ (451)	$ 3,751

(a) The following amounts of energy and capacity revenue relate to leases and are accounted for under ASC 840:

	Retail	Gulf Coast	East/West	Subtotal	Renewables	NRG Yield	Eliminations	Total
Energy revenue	$ —	$ —	$ —	$ —	$ 151	$ 284	$ —	$ 435
Capacity revenue	—	—	—	—	—	164	—	164
Other revenue	12	—	2	2	9	—	—	23

(b) The following amounts of energy and capacity revenue relate to derivative instruments and are accounted for under ASC 815.

	Retail	Gulf Coast	East/West	Subtotal	Renewables	NRG Yield	Eliminations	Total
Energy revenue	$ —	$ 981	$ 31	$ 1,012	$ —	$ —	$ —	$ 1,012
Capacity revenue	—	—	65	65	—	—	—	65
Other revenue	—	4	8	12	—	—	—	12

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

Contract Amortization

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

Lease Revenue

Certain of the Company's revenues are obtained through PPAs or other contractual agreements. Many of these agreements are accounted for as operating leases under ASC 840 Leases. Certain of these leases have no minimum lease payments and all of the rent is recorded as contingent rent on an actual basis when the electricity is delivered. Judgment is required by management in determining the economic life of each generating facility, in evaluating whether certain lease provisions constitute minimum payments or represent contingent rent and other factors in determining whether a contract contains a lease and whether the lease is an operating lease or capital lease.

Contract Balances

The following table reflects the contract assets and liabilities included in the Company's balance sheet as of June 30, 2018:

(In millions)		June 30, 2018
Deferred customer acquisition costs	$	102
Accounts receivable, net - Contracts with customers		1,187
Accounts receivable, net - Leases		152
Accounts receivable, net - Derivative instruments		32
Total accounts receivable, net	$	1,371
Unbilled revenues (included within Accounts receivable, net - Contracts with customers)		445
Deferred revenues		73

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.

Recent Accounting Developments - Guidance Adopted in 2018

ASU 2017-07 — In March 2017, the FASB issued ASU No. 2017-07, *Compensation - Retirement Benefits (Topic 715)*, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, or ASU No. 2017-07. Current GAAP does not indicate where the amount of net benefit cost should be presented in an entity's income statement and does not require entities to disclose the amount of net benefit cost that is included in the income statement. The amendments of ASU No. 2017-07 require an entity to report the service cost component of net benefit costs in the same line item as other compensation costs arising from services rendered by the related employees during the applicable service period. The other components of net benefit cost are required to be presented separately from the service cost component and outside the subtotal of income from operations. Further, ASU No. 2017-07 prescribes that only the service cost component of net benefit costs is eligible for capitalization. The Company adopted the amendments of ASU No. 2017-07 effective January 1, 2018. In connection with the adoption of the standard, the Company has applied the guidance retrospectively which resulted in an increase in cost of operations of $4 million and $8 million with a corresponding increase in other income, net on the statement of operations for the three and six months ended June 30, 2017, respectively.

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

Recent Accounting Developments - Guidance Not Yet Adopted

ASU 2016-02 — In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, or Topic 842, with the objective to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and to improve financial reporting by expanding the related disclosures. The guidance in Topic 842 provides that a lessee that may have previously accounted for a lease as an operating lease under current GAAP should recognize the assets and liabilities that arise from a lease on the balance sheet. In addition, Topic 842 expands the required quantitative and qualitative disclosures with regards to lease arrangements. The Company will adopt the standard effective January 1, 2019, and expects to elect certain of the practical expedients permitted, including the expedient that permits the Company to retain its existing lease assessment and classification. The Company is currently working through an adoption plan which includes the evaluation of lease contracts compared to the new standard. While the Company is currently evaluating the impact the new guidance will have on its financial position and results of operations, the Company expects to recognize lease liabilities and right of use assets. The extent of the increase to assets and liabilities associated with these amounts remains to be determined pending the Company’s review of its existing lease contracts and service contracts which may contain embedded leases. While this review is still in process, NRG believes the adoption of Topic 842 will have a material impact on its financial statements. The Company is also monitoring recent changes to Topic 842 and the related impact on the implementation process.

Note 3 — *Acquisitions, Discontinued Operations and Dispositions*

This footnote should be read in conjunction with the complete description under Note 3, *Discontinued Operations, Acquisitions and Dispositions*, to the Company's 2017 Form 10-K.

Acquisitions

XOOM Energy Acquisition — On June 1, 2018, the Company completed the acquisition of XOOM Energy, LLC, an electricity and natural gas retailer operating in 19 states, Washington, D.C. and Canada for approximately $219 million in cash, inclusive of approximately $54 million in payments for estimated working capital, which is subject to further adjustment. The acquisition increased NRG's retail portfolio by approximately 300,000 customers. The purchase price was provisionally allocated as follows: $2 million to cash, $8 million to restricted cash, $46 million to accounts receivable, $42 million to derivative assets, $169 million to customer relationships and contracts, $26 million to current and non-current assets, $25 million to accounts payable, $31 million to derivative liabilities, and $18 million to current and non-current liabilities.

Discontinued Operations

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 has concluded that it no longer controls GenOn as it is subject to the control of the Bankruptcy Court; and, accordingly, NRG no longer consolidates GenOn for financial reporting purposes.

By eliminating a large portion of its operations in the PJM market with the deconsolidation of GenOn, NRG has concluded that GenOn meets the criteria for discontinued operations, as this represents a strategic shift in the markets in which NRG operates. As such, all prior period results for GenOn have been reclassified as discontinued operations.

Summarized results of discontinued operations were as follows:

(In millions)	Three months ended June 30, 2018	Period from April 1, 2017 through June 14, 2017	Six months ended June 30, 2018	Period from January 1, 2017 through June 14, 2017
Operating revenues	$ —	$ 265	$ —	$ 646
Operating costs and expenses	—	(327)	—	(700)
Other expenses	—	(54)	—	(98)
Loss from operations of discontinued components, before tax	—	(116)	—	(152)
Income tax expense	—	8	—	9
Loss from operations of discontinued components	**—**	**(124)**	**—**	**(161)**
Interest income - affiliate	2	3	3	6
Loss from operations of discontinued components, net of tax	**2**	**(121)**	**3**	**(155)**
Pre-tax loss on deconsolidation	—	(208)	—	(208)
Settlement consideration and services credit	—	(289)	—	(289)
Pension and post-retirement liability assumption	1	(119)	1	(119)
Advisory and consulting fees	(1)	(4)	(2)	(4)
Other	(27)	—	(27)	—
Loss on disposal of discontinued components, net of tax	**(27)**	**(620)**	**(28)**	**(620)**
Loss from discontinued operations, net of tax	**$ (25)**	**$ (741)**	**$ (25)**	**$ (775)**

GenOn Settlement

Effective July 16, 2018, NRG and GenOn consummated the GenOn Settlement which accelerated certain terms contemplated by the plan of reorganization, as further described below. As a result, 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 and (iv) certain other balances due to NRG totaling $6 million. As of June 30, 2018, the Company had reserved for all amounts deemed to be uncollectible.

In order to facilitate the consummation of the GenOn Settlement, among other items, NRG assigned to GenOn approximately $8 million of historical claims against REMA in exchange for $4.2 million, which was credited as a reduction of the settlement payment. GenOn also indemnified NRG for any potential claims by REMA up to the amount of $10 million, and posted a letter of credit in that amount in favor of NRG as security for the indemnification. Other than those obligations which survive or are independent of the releases described herein, the GenOn Settlement provides NRG releases from GenOn and each of its debtor and non-debtor subsidiaries, excluding REMA.

Restructuring Support Agreement

Prior to the filing of GenOn's bankruptcy case, NRG, GenOn and certain holders representing greater than 93% in aggregate principal amount of GenOn’s Senior Notes and certain holders representing greater than 93% in aggregate principal amount of GenOn Americas Generation’s Senior Notes entered into a Restructuring Support Agreement that provided for a restructuring and recapitalization of the GenOn Entities through a prearranged plan of reorganization. In December 2017, the Bankruptcy Court approved the plan of reorganization, pursuant to an order of confirmation. Consummation of the plan of reorganization has not yet occurred and remains subject to the satisfaction or waiver of certain conditions precedent. Certain principal terms of the plan of reorganization are detailed below:

1) The dismissal of certain prepetition litigation and full releases from GenOn and each of its debtor and non-debtor subsidiaries in favor of NRG, excluding REMA.
2) NRG provided settlement cash consideration to GenOn of $261.3 million, paid in cash less amounts owed to NRG under the intercompany secured revolving credit facility. As of June 30, 2018, GenOn owed NRG approximately $151 million under the intercompany secured revolving credit facility, plus interest and fees accrued thereon. See Note 14, *Related Party Transactions* for further discussion of the intercompany secured revolving credit facility. The net liability for these amounts, along with the services credit described below, is recorded in accrued expenses and other current liabilities - affiliate as of June 30, 2018 and December 31, 2017.

3) NRG will retain the pension liability, including payment of approximately $13 million of 2017 pension contributions, for GenOn employees for service provided prior to the completion of the reorganization, which was paid in September 2017. GenOn’s pension liability as of June 30, 2018, was approximately $90 million. NRG will also retain the liability for GenOn’s post-employment and retiree health and welfare benefits, in an amount up to $25 million. These liabilities are recorded within other non-current liabilities as of June 30, 2018 and December 31, 2017.
4) The shared services agreement between NRG and GenOn was terminated and replaced as of the plan confirmation date with a 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. See Note 14, *Related Party Transactions*, for further discussion of the Services Agreement.
5) NRG provided a credit of $28 million to GenOn to apply against amounts owed under the transition services agreement. The unused credit of approximately $18 million was paid in cash to GenOn. The credit was intended to reimburse GenOn for its payment of financing costs.
6) NRG and GenOn also agreed to cooperate in good faith to maximize the value of certain development projects. Pursuant to this, GenOn made a one-time payment in the amount of $15 million to NRG in December 2017 as compensation for a purchase option with respect to the Canal 3 project. During the second quarter of 2018, NRG sold Canal 3 to Stonepeak Kestrel Holdings II LLC, or Stonepeak Kestrel, in conjunction with GenOn's sale of Canal Units 1 and 2 to Stonepeak Kestrel Holdings LLC. NRG reimbursed GenOn for $13.5 million of the one-time payment upon the closing of the sale of Canal 3.

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 $37.5 million in letters of credit as new qualifying credit support to GenOn Mid-Atlantic; and
- NRG paid approximately $6 million as reimbursement of professional fees incurred by certain of GenOn Mid-Atlantic's stakeholders in connection with the GenMA Settlement.

Dispositions

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 is non-recourse to NRG and was transferred to Stonepeak Kestrel in connection with the sale of Canal 3.

In addition, the Company completed other asset sales for $7 million of cash proceeds in the first half of 2018.

Transfers of Assets Under Common Control

On June 19, 2018, the Company completed the sale of the substantially completed assets of the UPMC Thermal Project to NRG Yield, Inc. for cash consideration of $84 million, subject to working capital adjustments.

On March 30, 2018, as part of the Transformation Plan, the Company sold to NRG Yield, Inc. 100% of NRG's interests in Buckthorn Renewables, LLC, which owns a 154-MW construction-stage utility-scale solar generation project, located in Texas. NRG Yield, Inc. paid cash consideration of approximately $42 million, excluding working capital adjustments, and assumed non-recourse debt of approximately $183 million. Concurrently, an initial contribution of approximately $19 million was received from the third-party investor in the underlying tax equity partnership, which is included in noncontrolling interest.

On March 27, 2017, the Company sold to NRG Yield, Inc.: (i) a 16% interest in the Agua Caliente solar project, representing ownership of approximately 46 net MW of capacity and (ii) NRG's interests in seven utility-scale solar projects located in Utah representing 265 net MW of capacity, which have reached commercial operations. NRG Yield, Inc. paid cash consideration of $130 million, plus $1 million in working capital adjustments, and assumed non-recourse debt of approximately $328 million.

Note 4 — *Fair Value of Financial Instruments*

This footnote should be read in conjunction with the complete description under Note 4, *Fair Value of Financial Instruments*, to the Company's 2017 Form 10-K.

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

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

	As of June 30, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Assets:				
Notes receivable [(a)]	$ 21	$ 18	$ 16	$ 15
Liabilities:				
Long-term debt, including current portion [(b)]	15,969	16,163	16,603	16,894

(a) Includes the current portion of notes receivable which is recorded in prepayments and other current assets on the Company's consolidated balance sheets.

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

The fair value of the Company's publicly-traded long-term debt is based on quoted market prices and is classified as Level 2 within the fair value hierarchy. The fair value of debt securities, non-publicly traded long-term debt and certain notes receivable of the Company are based on expected future cash flows discounted at market interest rates, or current interest rates for similar instruments with equivalent credit quality and are classified as Level 3 within the fair value hierarchy. The following table presents the level within the fair value hierarchy for long-term debt, including current portion as of June 30, 2018 and December 31, 2017:

	As of June 30, 2018		As of December 31, 2017	
	Level 2	Level 3	Level 2	Level 3
	(In millions)			
Long-term debt, including current portion	$ 9,586	$ 6,577	$ 8,934	$ 7,960

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 condensed consolidated balance sheets on a recurring basis and their level within the fair value hierarchy:

	As of June 30, 2018			
	Fair Value			
(In millions)	Total	Level 1	Level 2	Level 3
Investments in securities (classified within other non-current assets)	$ 22	$ 3	$ —	$ 19
Nuclear trust fund investments:				
Cash and cash equivalents	25	25	—	—
U.S. government and federal agency obligations	42	42	—	—
Federal agency mortgage-backed securities	97	—	97	—
Commercial mortgage-backed securities	16	—	16	—
Corporate debt securities	101	—	101	—
Equity securities	342	342	—	—
Foreign government fixed income securities	6	—	6	—
Other trust fund investments:				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Commodity contracts	1,169	188	481	500
Interest rate contracts	108	—	108	—
Measured using net asset value practical expedient:				
Equity securities — nuclear trust fund investments	65			
Total assets	$ 1,994	$ 601	$ 809	$ 519
Derivative liabilities:				
Commodity contracts	971	236	388	347
Interest rate contracts	23	—	23	—
Total liabilities	$ 994	$ 236	$ 411	$ 347

	As of December 31, 2017			
	Fair Value			
(In millions)	Total	Level 1	Level 2	Level 3
Investments in securities (classified within other non-current assets)	$ 22	$ 3	$ —	$ 19
Nuclear trust fund investments:				
Cash and cash equivalents	47	45	2	—
U.S. government and federal agency obligations	43	42	1	—
Federal agency mortgage-backed securities	82	—	82	—
Commercial mortgage-backed securities	14	—	14	—
Corporate debt securities	99	—	99	—
Equity securities	334	334	—	—
Foreign government fixed income securities	5	—	5	—
Other trust fund investments:				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Commodity contracts	745	191	509	45
Interest rate contracts	53	—	53	—
Measured using net asset value practical expedient:				
Equity securities — nuclear trust fund investments	68			
Total assets	$ 1,513	$ 616	$ 765	$ 64
Derivative liabilities:				
Commodity contracts	693	257	359	77
Interest rate contracts	59	—	59	—
Total liabilities	$ 752	$ 257	$ 418	$ 77

There were no transfers during the three and six months ended June 30, 2018 and 2017 between Levels 1 and 2. The following tables reconcile, for the three and six months ended June 30, 2018 and 2017, the beginning and ending balances for financial instruments that are recognized at fair value in the condensed consolidated financial statements, at least annually, using significant unobservable inputs:

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)					
	Three months ended June 30, 2018			Six months ended June 30, 2018		
(In millions)	Debt Securities	Derivatives[a]	Total	Debt Securities	Derivatives[a]	Total
Beginning balance	$ 19	$ (22)	$ (3)	$ 19	$ (32)	$ (13)
Contracts acquired in Xoom acquisition	—	12	12	—	12	12
Total losses — realized/unrealized:						
Included in earnings	—	(21)	(21)	—	(19)	(19)
Purchases	—	(4)	(4)	—	(3)	(3)
Transfers into Level 3 [b]	—	193	193	—	197	197
Transfers out of Level 3 [b]	—	(5)	(5)	—	(2)	(2)
Ending balance as of June 30, 2018	$ 19	$ 153	$ 172	$ 19	$ 153	$ 172
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 June 30, 2018	—	20	20	—	17	17

(a) Consists of derivative 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 in/out are with Level 2.

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)					
	Three months ended June 30, 2017			Six months ended June 30, 2017		
(In millions)	Debt Securities	Derivatives[a]	Total	Debt Securities	Derivatives[a]	Total
Beginning balance	$ 18	$ (56)	$ (38)	$ 17	$ (68)	$ (51)
Total gains — realized/unrealized:						
Included in earnings	—	40	40	1	46	47
Included in nuclear decommissioning obligation	—	—	—	—	—	—
Purchases	—	5	5	—	9	9
Transfers into Level 3 [b]	—	3	3	—	(5)	(5)
Transfers out of Level 3 [b]	—	(3)	(3)	—	7	7
Ending balance as of June 30, 2017	$ 18	$ (11)	$ 7	$ 18	$ (11)	$ 7
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 June 30, 2017	—	22	22	—	7	7

(a) Consists of derivative 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 in/out are with Level 2.

Derivative Fair Value Measurements

A portion of NRG's contracts are exchange-traded contracts with readily available quoted market prices. A majority of NRG's contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. The remainder of the assets and liabilities represent contracts for which external sources or observable market quotes are not available for the whole term or for certain delivery months or the contracts are retail and load following power contracts. These contracts are valued using various valuation techniques including but not limited to internal models that apply fundamental analysis of the market and corroboration with similar markets. As of June 30, 2018, contracts valued with prices provided by models and other valuation techniques make up 39% of the total derivative assets and 35% of the total derivative liabilities.

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 June 30, 2018 and December 31, 2017:

	Significant Unobservable Inputs						
	June 30, 2018						
	Fair Value				Input/Range		
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
	(In millions)						
Power Contracts	$ 481	$ 330	Discounted Cash Flow	Forward Market Price (per MWh)	$ 6	$ 198	$ 35
FTRs	19	17	Discounted Cash Flow	Auction Prices (per MWh)	(48)	47	—
	$ 500	$ 347					

	Significant Unobservable Inputs						
	December 31, 2017						
	Fair Value				Input/Range		
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
	(In millions)						
Power Contracts	$ 34	$ 65	Discounted Cash Flow	Forward Market Price (per MWh)	$ 10	$ 142	$ 33
FTRs	11	12	Discounted Cash Flow	Auction Prices (per MWh)	(28)	46	—
	$ 45	$ 77					

The following table provides sensitivity of fair value measurements to increases/(decreases) in significant unobservable inputs as of June 30, 2018 and December 31, 2017:

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

The fair value of each contract is discounted using a risk-free interest rate. In addition, the Company applies a credit reserve to reflect credit risk, which is calculated based on published default probabilities. As of June 30, 2018, the credit reserve resulted in a $4 million decrease in fair value which is composed of a $1 million loss in OCI and a $3 million loss in interest expense. As of December 31, 2017, the credit reserve resulted in no change in fair value in operating revenue and cost of operations.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, *Summary of Significant Accounting Policies*, to the Company's 2017 Form 10-K, the following is a discussion of the concentration of credit risk for the Company's contractual obligations. 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. NRG is exposed to counterparty credit risk through various activities including wholesale sales, fuel purchases and retail supply arrangements, and retail customer credit risk through its retail load activities.

Counterparty Credit Risk

The Company's counterparty credit risk policies are disclosed in its 2017 Form 10-K. As of June 30, 2018, the Company's counterparty credit exposure, excluding credit risk exposure under certain long term agreements, was $289 million with net exposure of $112 million. NRG held collateral (cash and letters of credit) against those positions of $246 million. Approximately 77% of the Company's exposure before collateral is expected to roll off by the end of 2019. 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 by Industry Sector	**Net Exposure [(a) (b)] (% of Total)**
Utilities, energy merchants, marketers and other	76%
Financial institutions	24
Total as of June 30, 2018	100%

Category by Counterparty Credit Quality	**Net Exposure [(a) (b)] (% of Total)**
Investment grade	76%
Non-Investment grade/Non-Rated	24
Total as of June 30, 2018	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.

NRG has counterparty credit risk exposure to certain counterparties, each of which represent more than 10% of total net exposure discussed above. The aggregate of such counterparties' exposure was $49 million as of June 30, 2018. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company's financial position or results of operations from nonperformance by any of NRG's counterparties.

RTOs and ISOs

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

Exchange Traded Transactions

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

Long Term Contracts

Counterparty credit exposure described above excludes credit risk exposure under certain long term agreements, including California tolling agreements, Gulf Coast load obligations, and wind and solar PPAs. As external sources or observable market quotes are not available to estimate such exposure, the Company estimates its credit exposure for 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 June 30, 2018, aggregate credit risk exposure managed by NRG to these counterparties was approximately $4.1 billion, including $2.5 billion related to assets of NRG Yield, Inc., for the next five years. This amount excludes potential credit exposures for projects with long-term PPAs that have not reached commercial operations. The majority of these power contracts are with utilities or public power entities with strong credit quality and public utility commission or other regulatory support. However, such regulated utility counterparties can be impacted by changes in government regulations or treatment by regulatory agencies which NRG is unable to predict.

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 June 30, 2018, the Company's retail customer credit exposure to C&I and Mass customers was diversified across many customers and various industries, as well as government entities.

Note 5 — *Nuclear Decommissioning Trust Fund*

This footnote should be read in conjunction with the complete description under Note 6, *Nuclear Decommissioning Trust Fund*, to the Company's 2017 Form 10-K.

NRG's Nuclear Decommissioning Trust Fund assets are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. NRG accounts for the Nuclear Decommissioning Trust Fund in accordance with ASC 980, *Regulated Operations*, 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 OCI, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses (including other-than-temporary impairments) for the securities held in the trust funds, as well as information about the contractual maturities of those securities.

	As of June 30, 2018				As of December 31, 2017			
(In millions, except otherwise noted)	**Fair Value**	**Unrealized Gains**	**Unrealized Losses**	**Weighted-average Maturities (In years)**	**Fair Value**	**Unrealized Gains**	**Unrealized Losses**	**Weighted-average Maturities (In years)**
Cash and cash equivalents	$ 25	$ —	$ —	—	$ 47	$ —	$ —	—
U.S. government and federal agency obligations	42	1	—	14	43	1	—	11
Federal agency mortgage-backed securities	97	—	3	23	82	1	1	23
Commercial mortgage-backed securities	16	—	1	22	14	—	—	20
Corporate debt securities	101	1	2	10	99	2	1	11
Equity securities	407	272	—	—	402	272	—	—
Foreign government fixed income securities	6	—	—	8	5	—	—	9
Total	$ 694	$ 274	$ 6		$ 692	$ 276	$ 2	

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

	Six months ended June 30,	
	2018	2017
	(In millions)	
Realized gains	$ 7	$ 3
Realized losses	6	3
Proceeds from sale of securities	$ 303	$ 277

Note 6 — *Accounting for Derivative Instruments and Hedging Activities*

This footnote should be read in conjunction with the complete description under Note 5, *Accounting for Derivative Instruments and Hedging Activities*, to the Company's 2017 Form 10-K.

Energy-Related Commodities

As of June 30, 2018, NRG had energy-related derivative instruments extending through 2031. The Company marks these derivatives to market through the statement of operations.

Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company's issuance of variable rate debt. In order to manage the Company's interest rate risk, NRG enters into interest rate swap agreements. As of June 30, 2018, NRG had interest rate derivative instruments on recourse debt extending through 2021, which are not designated as cash flow hedges. The Company had interest rate swaps on non-recourse debt extending through 2041, a portion of which are designated as cash flow hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG's open derivative transactions broken out by category, excluding those derivatives that qualified for the NPNS exception, as of June 30, 2018 and December 31, 2017. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

		Total Volume	
		June 30, 2018	December 31, 2017
Category	Units	(In millions)	
Emissions	Short Ton	2	1
Coal	Short Ton	12	21
Natural Gas	MMBtu	(551)	(17)
Power	MWh	16	14
Capacity	MW/Day	(1)	(1)
Interest	Dollars	$ 4,016	$ 3,876
Equity	Shares	—	1

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

Fair Value of Derivative Instruments

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

	Fair Value			
	Derivative Assets		Derivative Liabilities	
	June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
	(In millions)			
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$ 3	$ 1	$ 2	$ 5
Interest rate contracts long-term	23	11	5	11
Total Derivatives Designated as Cash Flow or Fair Value Hedges	26	12	7	16
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	16	9	5	15
Interest rate contracts long-term	66	32	11	28
Commodity contracts current	832	616	702	535
Commodity contracts long-term	337	129	269	158
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	1,251	786	987	736
Total Derivatives	$ 1,277	$ 798	$ 994	$ 752

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 of derivatives by counterparty master agreement level and collateral received or paid:

		Gross Amounts Not Offset in the Statement of Financial Position		
As of June 30, 2018	Gross Amounts of Recognized Assets / Liabilities	Derivative Instruments	Cash Collateral (Held) / Posted	Net Amount
	(In millions)			
Commodity contracts:				
Derivative assets	$ 1,169	$ (817)	$ (50)	$ 302
Derivative liabilities	(971)	817	98	(56)
Total commodity contracts	198	—	48	246
Interest rate contracts:				
Derivative assets	108	(3)	—	105
Derivative liabilities	(23)	3	—	(20)
Total interest rate contracts	85	—	—	85
Total derivative instruments	$ 283	$ —	$ 48	$ 331

		Gross Amounts Not Offset in the Statement of Financial Position		
As of December 31, 2017	Gross Amounts of Recognized Assets / Liabilities	Derivative Instruments	Cash Collateral (Held) / Posted	Net Amount
	(In millions)			
Commodity contracts:				
Derivative assets	$ 745	$ (578)	$ (11)	$ 156
Derivative liabilities	(693)	578	73	(42)
Total commodity contracts	52	—	62	114
Interest rate contracts:				
Derivative assets	53	(3)	—	50
Derivative liabilities	(59)	3	—	(56)
Total interest rate contracts	(6)	—	—	(6)
Total derivative instruments	$ 46	$ —	$ 62	$ 108

Accumulated Other Comprehensive Loss

The following table summarizes the effects of ASC 815 on the Company's accumulated OCI balance attributable to cash flow hedge derivatives, net of tax:

	Interest Rate Contracts			
	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Accumulated OCI beginning balance	$ (31)	$ (61)	$ (54)	$ (66)
Reclassified from accumulated OCI to income:				
Due to realization of previously deferred amounts	3	3	7	6
Mark-to-market of cash flow hedge accounting contracts	5	(9)	24	(7)
Accumulated OCI ending balance, net of $5, and $16 tax	$ (23)	$ (67)	$ (23)	$ (67)
Losses expected to be realized from OCI during the next 12 months, net of $1 tax	$ 8		$ 8	

Amounts reclassified from accumulated OCI into income are recorded to interest expense for interest rate contracts.

The Company's regression analysis for Marsh Landing, Walnut Creek, and Avra Valley interest rate swaps, while positively correlated, no longer contain match terms for cash flow hedge accounting. As a result, the Company voluntarily de-designated the Marsh Landing, Walnut Creek, and Avra Valley cash flow hedges as of April 28, 2017, and will prospectively mark these derivatives to market through the income statement.

Impact of Derivative Instruments on the Statements 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 consolidated results of operations.

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 energy commodity contracts is included within operating revenues and cost of operations and the effect of interest rate contracts is included in interest expense.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Unrealized mark-to-market results	(In millions)			
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (3)	$ 22	$ (1)	$ 25
Reversal of acquired (gain)/loss positions related to economic hedges	(1)	1	(1)	1
Net unrealized (losses)/gains on open positions related to economic hedges	(67)	36	127	15
Total unrealized mark-to-market (losses)/gains for economic hedging activities	(71)	59	125	41
Reversal of previously recognized unrealized gains on settled positions related to trading activity	(3)	(4)	(6)	(19)
Net unrealized gains on open positions related to trading activity	8	16	19	17
Total unrealized mark-to-market gains/(losses) for trading activity	5	12	13	(2)
Total unrealized (losses)/gains	$ (66)	$ 71	$ 138	$ 39

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Unrealized gains/(losses) included in operating revenues	$ 20	$ 53	$ (78)	$ 157
Unrealized (losses)/gains included in cost of operations	(86)	18	216	(118)
Total impact to statement of operations — energy commodities	$ (66)	$ 71	$ 138	$ 39
Total impact to statement of operations — interest rate contracts	$ 13	$ (24)	$ 61	$ (19)

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

For the six months ended June 30, 2018, the $127 million unrealized gain from open economic hedge positions was primarily the result of an increase in value of forward purchases of ERCOT heat rate and ERCOT electricity contracts due to ERCOT heat rate expansion and increases in ERCOT power prices.

For the six months ended June 30, 2017, the $15 million unrealized gain from open economic hedge positions was primarily the result of an increase in value of forward sales of PJM electricity and New York capacity due to decreases in PJM electricity and New York capacity prices, which was offset by a decrease in value of forward purchases of natural gas and coal due to decreases in natural gas and coal prices.

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 with adequate assurance clauses that are in a net liability position as of June 30, 2018, was $31 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of June 30, 2018, was $3 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 $4 million as of June 30, 2018.

See Note 4, *Fair Value of Financial Instruments*, to this Form 10-Q for discussion regarding concentration of credit risk.

Note 7 — *Impairments*

2018 Impairment Losses

Keystone and Conemaugh — On June 29, 2018, the Company entered into an agreement to sell its approximately 3.7% interests in the Keystone and Conemaugh generating stations. 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. The transaction is expected to close in the third quarter of 2018.

Dunkirk — During the second quarter of 2018, NRG ceased its development of the project to add gas capability at the Dunkirk generating station. The project was put on hold in 2015 pending the resolution of a lawsuit filed by Entergy Corporation against the NYPSC which challenged the legality of the Dunkirk contract. The lawsuit was later dropped and development continued, but the delay imposed a new requirement on Dunkirk to enter into the NYISO interconnection process. The NYISO studies have shown that it would cause the Company to incur a material increase in costs. In addition, the interconnection upgrades that the NYISO has identified may not be ready until December 2023, which represents a significant delay the project schedule. This caused the Company to record an impairment loss of $46 million, reducing the carrying amount of the related assets to $0.

2017 Impairment Losses

Bacliff Project — On June 16, 2017, NRG Texas Power LLC provided notice to BTEC New Albany, LLC that it was exercising its right to terminate the Amended and Restated Membership Interest Purchase Agreement, or MIPA, due to the Bacliff Project, a new peaking facility at the former P.H. Robinson Electric Generating Station, not achieving commercial completion by the contractual expiration date of May 31, 2017. As a result of the MIPA termination, the Company recorded an impairment loss of $41 million to reduce the carrying amount of the related construction in progress to $0 during the second quarter of 2017. Subsequent to the MIPA termination, BTEC filed claims against NRG Texas Power LLC with respect to the termination of the MIPA and NRG filed counterclaims against BTEC as further described in Note 15, *Commitments and Contingencies*. On June 7, 2018, the parties resolved all claims and counterclaims in the lawsuit.

Other Impairments — During the second quarter of 2017, the Company recorded impairment losses of approximately $22 million in connection with the Company's Renewables business.

Note 8 — *Debt and Capital Leases*

This footnote should be read in conjunction with the complete description under Note 12, *Debt and Capital Leases*, to the Company's 2017 Form 10-K. Long-term debt and capital leases consisted of the following:

(In millions, except rates)	June 30, 2018	December 31, 2017	June 30, 2018 interest rate % (a)
Recourse debt:			
Senior Notes, due 2022	$ 977	$ 992	6.250
Senior Notes, due 2024	733	733	6.250
Senior Notes, due 2026	1,000	1,000	7.250
Senior Notes, due 2027	1,250	1,250	6.625
Senior Notes, due 2028	841	870	5.750
Convertible Senior Notes, due 2048	575	—	2.750
Revolving loan facility, due 2018 and 2021	26	—	L+1.75
Term loan facility, due 2023	1,862	1,872	L+1.75
Tax-exempt bonds	465	465	4.125 - 6.00
Subtotal recourse debt	7,729	7,182	
Non-recourse debt:			
NRG Yield, Inc. Convertible Senior Notes, due 2019	345	345	3.500
NRG Yield, Inc. Convertible Senior Notes, due 2020	288	288	3.250
NRG Yield Operating LLC Senior Notes, due 2024	500	500	5.375
NRG Yield Operating LLC Senior Notes, due 2026	350	350	5.000
NRG Yield LLC and NRG Yield Operating LLC Revolving Credit Facility, due 2023 (b)	—	55	L+1.75
El Segundo Energy Center, due 2023	369	400	L+1.75 - L+2.375
Marsh Landing, due 2023	305	318	L+2.125
Alta Wind I - V lease financing arrangements, due 2034 and 2035	901	926	5.696 - 7.015
Walnut Creek, term loans due 2023	254	267	L+1.625
Utah Portfolio, due 2022	273	278	various
Tapestry, due 2021	155	162	L+1.625
CVSR, due 2037	731	746	2.339 - 3.775
CVSR HoldCo, due 2037	188	194	4.680
Alpine, due 2022	133	135	L+1.750
Energy Center Minneapolis, due 2031, 2033, 2035 and 2037	328	208	various
Viento, due 2023	154	163	L+3.00
Buckthorn Solar, due 2018 and 2025	132	169	L+1.750
NRG Yield - other	564	579	various
Subtotal NRG Yield debt (non-recourse to NRG) (c)	5,970	6,083	
Ivanpah, due 2033 and 2038 (e)	—	1,073	2.285 - 4.256
Carlsbad Energy Project (c)	513	427	L+1.625 - 4.120
Agua Caliente, due 2037	812	818	2.395 - 3.633
Agua Caliente Borrower 1, due 2038	86	89	5.430
Cedro Hill, due 2025 (c)	144	151	L+1.75
Midwest Generation, due 2019	108	152	4.390
NRG Other Renewables (c)	623	478	various
NRG Other	107	180	various
Subtotal other NRG non-recourse debt	2,393	3,368	
Subtotal all non-recourse debt	8,363	9,451	
Subtotal long-term debt (including current maturities)	16,092	16,633	
Capital leases	3	5	various
Subtotal long-term debt and capital leases (including current maturities)	16,095	16,638	
Less current maturities (d)	(952)	(688)	
Less debt issuance costs	(199)	(204)	
Discounts	(123)	(30)	
Total long-term debt and capital leases	$ 14,821	$ 15,716	

(a) As of June 30, 2018, L+ equals 3-month LIBOR plus x%, except for Carlsbad, the Buckthorn Solar and Utah Solar Portfolio where L+ equals 1 month LIBOR plus x% and Viento where L+ equals 6-month LIBOR plus x%.
(b) Applicable rate is determined by the Borrower Leverage Ratio, as defined in the credit agreement.
(c) Debt associated with the asset sales announced in February 2018.
(d) The NRG Yield, Inc. Convertible Senior Notes, due 2019, become due in February 2019 and are recorded in current maturities as of June 30, 2018.
(e) The Company deconsolidated Ivanpah during the second quarter of 2018.

Recourse Debt

2023 Term Loan Facility

On March 21, 2018, NRG 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%.

Senior Notes

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 $9.5 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.

Senior Note Repurchases

In connection with the Transformation Plan, the Company has committed to reduce its debt balance by an additional $640 million to achieve a target net debt to adjusted EBITDA credit ratio of 3.0/1. The following open market senior note repurchases were completed to assist in achieving this target.

In connection with the repurchases during the six months ended June 30, 2018, a $1 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $1 million.

In millions, except rates	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	6	6	103.25%
5.750% senior notes due 2028	20	21	99.13%
6.625% senior notes due 2027	20	21	103.06%
Total at August 2, 2018	$ 89	$ 93	

(a) Includes payment for accrued interest of $1 million.

Non-recourse Debt

NRG Yield LLC and NRG Yield Operating LLC Revolving Credit Facility

NRG Yield LLC and its direct wholly owned subsidiary, NRG Yield Operating LLC, are parties to a senior secured revolving credit facility, which can be used for cash and for the issuance of letters of credit. On April 30, 2018, NRG Yield LLC and NRG Yield Operating LLC refinanced the revolving credit facility, which extended the maturity of the facility to April 28, 2023, and decreased the overall cost of borrowing from L+ 2.50% to L+1.75%. At June 30, 2018, there was $67 million of letters of credit issued under the revolving credit facility and no outstanding borrowings on the revolver.

Project Financings

Thermal Financing

On June 19, 2018, NRG Energy Center Minneapolis, a subsidiary of NRG Yield LLC, entered into an amended and restated Thermal note purchase and private shelf agreement whereas it authorized the issuance of the Series E Notes, Series F Notes, Series G Notes, and Series H Notes, as further described in the table below:

In millions, except rates		Amount	Interest Rate
Energy Center Minneapolis Series E Notes, due 2033	$	70	4.80%
Energy Center Minneapolis Series F Notes, due 2033		10	4.60%
Energy Center Minneapolis Series G Notes, due 2035		83	5.90%
Energy Center Minneapolis Series H Notes, due 2037		40	4.83%
Total proceeds	**$**	**203**	
Repayment of Energy Center Minneapolis Series C Notes, due 2025		(83)	5.95%
Net borrowings	**$**	**120**	

The Series G Notes were used to refinance the Series C Notes due 2025. The amended and restated Thermal note purchase and private shelf agreement also established a private shelf facility for the future issuance of notes in the amount of $40 million.

Rosamond Financing

On June 4, 2018, Rosamond Solar Portfolio, LLC entered into a financing agreement with financial institutions for a $118 million construction loan, which will convert to a term loan upon completion of project construction and a $175 million investment tax credit, or ITC, bridge loan, both of which have an interest rate of LIBOR plus 1.75%, as well as a letter of credit facility with availability of up to $33 million. The ITC bridge loan is expected to be repaid with proceeds from a tax equity arrangement by April 30, 2019. The term loan matures on April 30, 2034. As of June 30, 2018, $83 million and $5 million had been borrowed under the construction loan and the ITC bridge loan, respectively.

Agua Caliente Project Financing

On February 17, 2017, Agua Caliente Borrower 1 LLC and Agua Caliente Borrower 2 LLC, or Agua Caliente Holdco, the indirect owners of 51% of the Agua Caliente solar facility, issued $130 million of senior secured notes under the Agua Caliente Holdco Financing Agreement, or 2038 Agua Caliente Holdco Notes, that bear interest at 5.43% and mature on December 31, 2038. As described in Note 3, *Acquisitions, Discontinued Operations and Dispositions*, on March 27, 2017, NRG Yield, Inc. acquired Agua Caliente Borrower 2 LLC from NRG. The debt is joint and several with respect to Agua Caliente Borrower 1 LLC and Agua Caliente Borrower 2 LLC and is secured by the equity interests of each borrower in the Agua Caliente solar facility.

Carlsbad Project Financing

On May 26, 2017, Carlsbad Energy Holdings, LLC entered into a note payable agreement with financial institutions for the issuance of up to $407 million of senior secured notes that bear interest at a rate of 4.12%, and mature on October 31, 2038, and a credit agreement for a $194 million construction loan, that will convert to a term loan upon completion of the project as well as a letter of credit facility with an aggregate principal amount not to exceed $83 million, and a working capital loan facility with an aggregate principal amount not to exceed $4 million. As of June 30, 2018, $513 million was outstanding under both the note and the construction loan.

Note 9 — *Variable Interest Entities, or VIEs*

Entities that are not Consolidated

NRG has interests in entities that are considered VIEs under ASC 810, *Consolidation*, but NRG is not considered the primary beneficiary. NRG accounts for its interests in these entities under the equity method of accounting.

Utility-Scale Solar Portfolio — Through its consolidated subsidiary, NRG Yield, Inc., the Company has equity interests in Four Brothers Solar, LLC, Granite Mountain Holdings, LLC, and Iron Springs Holdings, LLC, which are accounted for as equity method investments as the Company does not have a controlling financial interest. The assets have 20-year PPAs with PacifiCorp. NRG's maximum exposure to loss is limited to its equity investment, which was $338 million as of June 30, 2018.

GenConn Energy LLC **—** Through its consolidated subsidiary, NRG Yield, Inc., the Company owns a 50% interest in GCE Holding LLC, the owner of GenConn, which owns and operates two 190-MW peaking generation facilities in Connecticut at NRG's Devon and Middletown sites. NRG's maximum exposure to loss is limited to its equity investment, which was $100 million as of June 30, 2018.

Ivanpah Master Holdings LLC — Through its consolidated subsidiary, NRG Solar Ivanpah LLC, the Company owns a 54.6% 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 392 MW. The 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, including the planned sale of NRG's renewables platform. 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, Consolidations. 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 during the six months ended June 30, 2018. 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. NRG's maximum exposure to loss is limited to its equity investment, which was $57 million as of June 30, 2018.

Entities that are Consolidated

The Company has a controlling financial interest in certain entities which have been identified as VIEs under ASC 810. These arrangements are primarily related to tax equity arrangements entered into with third-parties in order to finance the cost of solar energy systems under operating leases and wind facilities eligible for certain tax credits as further described in Note 2, *Summary of Significant Accounting Policies* to the Company's 2017 Form 10-K. For one of the tax equity arrangements, the Company has a deficit restoration obligation equal to $83 million as of June 30, 2018, which would be required to be funded if the arrangement were to be dissolved.

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

(In millions)	June 30, 2018	December 31, 2017
Current assets	$ 191	$ 118
Net property, plant and equipment	2,709	2,337
Other long-term assets	660	658
Total assets	3,560	3,113
Current liabilities	119	96
Long-term debt	814	661
Other long-term liabilities	211	209
Total liabilities	1,144	966
Redeemable noncontrolling interest	69	78
Noncontrolling interest	660	507
Net assets less noncontrolling interest	$ 1,687	$ 1,562

Note 10 — *Changes in Capital Structure*

As of June 30, 2018 and December 31, 2017, the Company had 500,000,000 shares of common stock authorized. The following table reflects the changes in NRG's common stock issued and outstanding:

	Issued	Treasury	Outstanding
Balance as of December 31, 2017	418,323,134	(101,580,045)	316,743,089
Shares issued under LTIPs	1,373,655	—	1,373,655
Shares issued under ESPP	—	175,862	175,862
Shares repurchased	—	(14,863,301)	(14,863,301)
Balance as of June 30, 2018	419,696,789	(116,267,484)	303,429,305

Employee Stock Purchase Plan

In January 2018, 175,862 shares of common stock were issued to employee accounts from treasury stock for the offering period of July 1, 2017, to December 31, 2017. In January 2018, NRG suspended the ESPP.

Share Repurchases

In February 2018, the Company's board of directors authorized the Company to repurchase $1 billion of its common stock, with the first $500 million program beginning as soon as permitted. The following repurchases have been made during the six months ended June 30, 2018.

	Total number of shares purchased	Average price paid per share [(a)]	Amounts paid for shares purchased (in millions) [(a)]
Board Authorized Share Repurchases			
First Quarter 2018	3,114,748		$ 93
Second Quarter 2018 [(b)]	11,748,553		407
Total Board Authorized Share Repurchases as of June 30, 2018	14,863,301		$ 500
July 2018	860,880		—
Total Board Authorized Share Repurchases as of August 2, 2018	15,724,181	$ 31.80	$ 500

(a) The average price paid per share and amounts paid for shares purchased exclude the commissions of $0.01 per share paid in connection with the share repurchase.
(b) The share repurchases for the second quarter include 9,969,023 of the shares repurchased through the ASR Agreement, as described below.

Accelerated Share Repurchase

On May 24, 2018, the Company executed an accelerated share repurchase agreement, or ASR Agreement, with a financial institution to repurchase a total of $354 million of outstanding common stock based on a volume weighted average price. The Company received initial shares of 9,969,023, which were recorded in treasury stock at fair value based on the closing price of $343 million, with the remaining $11 million recorded in additional paid in capital, representing the value of the forward contract to purchase additional shares. In July 2018, the financial institution delivered the remaining shares pursuant to the ASR Agreement and the Company received an additional 860,880 shares. The average price paid for all of the shares delivered under the ASR Agreement was $32.69 per share. Upon receipt of the additional shares, the Company transferred the $11 million from additional paid in capital to treasury stock.

NRG Common Stock Dividends

The following table lists the dividends paid during the six months ended June 30, 2018:

	Second Quarter 2018	First Quarter 2018
Dividends per Common Share	$ 0.03	$ 0.03

On July 18, 2018, NRG declared a quarterly dividend on the Company's common stock of $0.03 per share, payable August 15, 2018, to stockholders of record as of August 1, 2018, representing $0.12 per share on an annualized basis.

The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws, regulations and other contractual obligations.

Note 11 — *Earnings/(Loss) Per Share*

Basic earnings/(loss) per common share is computed by dividing net income/(loss) less accumulated preferred stock dividends by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted earnings/(loss) per share is computed in a manner consistent with that of basic income/(loss) per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The reconciliation of NRG's basic and diluted loss per share is shown in the following table:

	Three months ended June 30,		Six months ended June 30,	
In millions, except per share data	**2018**	**2017**	**2018**	**2017**
Basic income/(loss) per share attributable to NRG Energy, Inc. common stockholders				
Net income/(loss) attributable to NRG Energy, Inc.	$ 72	$ (626)	$ 351	$ (790)
Weighted average number of common shares outstanding - basic	310	316	314	316
Earnings/(loss) per weighted average common share — basic	$ 0.23	$ (1.98)	$ 1.12	$ (2.50)
Diluted income/(loss) per share attributable to NRG Energy, Inc. common stockholders				
Weighted average number of common shares outstanding - diluted	310	316	314	316
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	4	—	4	—
Total dilutive shares	314	316	318	316
Earnings/(loss) per weighted average common share — diluted	$ 0.23	$ (1.98)	$ 1.10	$ (2.50)

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 loss per share:

	Three months ended June 30,		Six months ended June 30,	
In millions of shares	**2018**	**2017**	**2018**	**2017**
Equity compensation plans	—	6	1	6
Total	—	6	1	6

Note 12 — *Segment Reporting*

The Company's segment structure reflects how management currently makes financial decisions and allocates resources. The Company's businesses are segregated as follows: Generation, which includes generation, international and BETM; Retail, which includes Mass customers and Business Solutions, which includes C&I customers and other distributed and reliability products; Renewables, which includes solar and wind assets, excluding those in NRG Yield; NRG Yield; and corporate activities.

During 2017, NRG Yield acquired several projects totaling 555 MW from NRG. On March 30, 2018, 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. These acquisitions were treated as a transfer of entities under common control and accordingly, all historical periods have been recast to reflect the acquisitions as if they had occurred at the beginning of the financial statement period.

On June 14, 2017, as described in Note 3, *Acquisitions, Discontinued Operations and Dispositions*, NRG deconsolidated GenOn for financial reporting purposes. The financial information for all historical periods have been recast to reflect the presentation of GenOn as discontinued operations within the corporate segment.

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

	Retail[(a)]	Generation[(a)]	Renewables[(a)]	NRG Yield	Corporate[(a)]	Eliminations	Total
Three months ended June 30, 2018				**(In millions)**			
Operating revenues[(a)]	$ 1,817	$ 1,218	$ 113	$ 307	$ 7	$ (540)	$ 2,922
Depreciation and amortization	31	66	40	82	8	—	227
Impairment losses	—	74	—	—	—	—	74
Reorganization costs	1	3	3	—	16	—	23
Equity in earnings/(losses) of unconsolidated affiliates	—	—	5	29	—	(16)	18
(Loss)/income from continuing operations before income taxes	(84)	273	(17)	103	(134)	(12)	129
(Loss)/income from continuing operations	(84)	272	(12)	96	(139)	(12)	121
Loss from discontinued operations, net of tax	—	—	—	—	(25)	—	(25)
Net (Loss)/Income	(84)	272	(12)	96	(164)	(12)	96
(Loss)/Income attributable to NRG Energy, Inc.	**$ (88)**	**$ 272**	**$ (35)**	**$ 73**	**$ (244)**	**$ 94**	**$ 72**
Total assets as of June 30, 2018	**$ 7,217**	**$ 4,306**	**$ 4,117**	**$ 8,448**	**$ 9,675**	**$ (10,816)**	**$ 22,947**
(a) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 2	$ 546	$ 9	$ —	$ (17)	$ —	$ 540

	Retail[(a)]	Generation[(a)]	Renewables[(a)]	NRG Yield	Corporate[(a)]	Eliminations	Total
Three months ended June 30, 2017				**(In millions)**			
Operating revenues[(a)]	$ 1,603	$ 882	$ 119	$ 288	$ 3	$ (194)	$ 2,701
Depreciation and amortization	29	95	49	79	8	—	260
Impairment losses	—	41	22	—	—	—	63
Equity in (losses)/earnings of unconsolidated affiliates	—	(15)	(2)	16	3	(5)	(3)
Income/(loss) from continuing operations before income taxes	330	(89)	(51)	52	(134)	(5)	103
Income/(loss) from continuing operations	341	(90)	(46)	44	(145)	(5)	99
Loss from discontinued operations, net of tax	—	—	—	—	(741)	—	(741)
Net Income/(Loss)	341	(90)	(46)	44	(886)	(5)	(642)
Net Income/(Loss) attributable to NRG Energy, Inc.	**$ 341**	**$ (90)**	**$ (21)**	**$ 38**	**$ (919)**	**$ 25**	**$ (626)**
(a) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 1	$ 171	$ 3	$ —	$ 19	$ —	$ 194

Six months ended June 30, 2018	Retail[a]	Generation[a]	Renewables[a]	NRG Yield	Corporate[a]	Eliminations	Total
				(In millions)			
Operating revenues[a]	$ 3,298	$ 1,545	$ 199	$ 532	$ 9	$ (240)	$ 5,343
Depreciation and amortization	59	133	90	163	17	—	462
Impairment losses	—	74	—	—	—	—	74
Reorganization costs	4	7	3	—	29	—	43
Equity in earnings/(losses) of unconsolidated affiliates	—	2	5	33	(1)	(23)	16
Income/(Loss) from continuing operations before income taxes	861	(264)	(56)	102	(260)	(22)	361
Income/(Loss) from continuing operations	861	(265)	(45)	96	(271)	(22)	354
Income from discontinued operations, net of tax	—	—	—	—	(25)	—	(25)
Net Income/(Loss)	861	(265)	(45)	96	(296)	(22)	329
Net Income/(Loss) attributable to NRG Energy, Inc.	**$ 851**	**$ (265)**	**$ (33)**	**$ 94**	**$ (392)**	**$ 96**	**$ 351**
(a) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 3	$ 239	$ 17	$ —	$ (19)	$ —	$ 240

Six months ended June 30, 2017	Retail [a]	Generation[a]	Renewables[a]	NRG Yield	Corporate[a]	Eliminations	Total
Operating revenues[a]	$ 2,938	$ 1,848	$ 213	$ 509	$ 11	$ (436)	$ 5,083
Depreciation and amortization	57	192	96	156	16	—	517
Impairment losses	—	41	22	—	—	—	63
Equity in (losses)/earnings of unconsolidated affiliates	—	(28)	(3)	35	7	(9)	2
Income/(loss) from continuing operations before income taxes	303	(52)	(87)	49	(275)	(9)	(71)
Income/(loss) from continuing operations	311	(54)	(77)	42	(283)	(9)	(70)
Loss from discontinued operations, net of tax	—	—	—	—	(775)	—	(775)
Net Income/(loss)	311	(54)	(77)	42	(1,058)	(9)	(845)
Net Income/(loss) attributable to NRG Energy, Inc.	**$ 311**	**$ (54)**	**$ (24)**	**$ 50**	**$ (1,091)**	**$ 18**	**$ (790)**
(a) Operating revenues include inter-segment sales and net derivative gains and losses of:	$ 11	$ 406	$ 4	$ —	$ 15	$ —	$ 436

Note 13 — *Income Taxes*

Effective Tax Rate

The income tax provision consisted of the following:

	Three months ended June 30,		Six months ended June 30,	
In millions, except rates	**2018**	**2017**	**2018**	**2017**
Income/(Loss) before income taxes	$ 129	$ 103	$ 361	$ (71)
Income tax expense/(benefit) from continuing operations	8	4	7	(1)
Effective tax rate	6.2%	3.9%	1.9%	1.4%

For the three and six months ended June 30, 2018, NRG's overall effective tax rate was different than the statutory rate of 21% primarily due to the tax benefit for the change in valuation allowance and the generation of PTCs from various wind facilities partially offset by the inclusion of consolidated partnerships and the current state tax expense.

For the three months ended June 30, 2017, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the tax benefit for the change in valuation allowance and the generation of PTCs and ITCs from various wind and solar facilities, respectively, partially offset by the inclusion of consolidated partnerships and current state tax expense.

For the six months ended June 30, 2017, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the tax expense for the change in valuation allowance and current state tax expense, partially offset by the generation of PTCs and ITCs from various wind and solar facilities, respectively.

Uncertain Tax Benefits

As of June 30, 2018, NRG has recorded a non-current tax liability of $39 million for uncertain tax benefits from positions taken on various state income tax returns, including accrued interest. For the six months ended June 30, 2018, NRG accrued an immaterial amount of interest relating to the uncertain tax benefits. As of June 30, 2018, NRG had cumulative interest and penalties related to these uncertain tax benefits of $5 million. The Company recognizes interest and penalties related to uncertain tax benefits in income tax expense.

NRG is subject to examination by taxing authorities for income tax returns filed in the U.S. federal jurisdiction and various state and foreign jurisdictions including operations located in Australia. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2015. With few exceptions, state and local income tax examinations are no longer open for years before 2010.

Note 14 — *Related Party Transactions*

Services Agreement and Transition Services Agreement with GenOn

The Company provides 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, or the Services Agreement. The initial term of the Services Agreement was through December 31, 2013, with an automatic renewal absent a request for termination. The fee charged was determined based on a fixed amount as described in the Services Agreement and was calculated based on historical GenOn expenses prior to the NRG Merger. The annual fees under the Services Agreement were approximately $193 million and management has concluded that this method of charging overhead costs is reasonable. As described in Note 3, *Acquisitions, Discontinued Operations and Dispositions*, in connection with the Restructuring Support Agreement, 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 3, *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. NRG may provide additional separation services that are necessary for or reasonably related to the operation of GenOn's business after such date, subject to NRG's prior written consent, not to be unreasonably withheld. For the three and six months ended June 30, 2018, NRG recorded approximately $21 million and $42 million, respectively, under the transition services agreement against selling, general and administrative expenses post-Chapter 11 Filing. For the three and six months ended June 30, 2017, NRG recorded other income - affiliate related to these services of $39 million and $87 million, respectively.

Credit Agreement with GenOn

NRG and GenOn are 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. At June 30, 2018 and December 31, 2017, $45 million and $92 million, respectively, of letters of credit were issued and outstanding under the NRG credit agreement for GenOn. Additionally, as of June 30, 2018 and December 31, 2017, there were $151 million and $125 million, respectively, of loans outstanding under the intercompany secured revolving credit facility. In addition, the intercompany secured revolving credit facility contains customary covenants and events of default. As of June 30, 2018, GenOn was in default under the secured intercompany revolving credit agreement due to the filing of the Chapter 11 Cases.

As a result of the Chapter 11 Cases, no additional revolving loans or letters of credit are available to GenOn. As the Restructuring Support Agreement provided that the borrowings be repaid to NRG at or prior to emergence, NRG recorded its affiliate receivable for the amount outstanding net within accrued expenses and other current liabilities - affiliate on the consolidated balance sheet as of June 30, 2018. Interest continued to accrue during the pendency of the Chapter 11 Cases until July 2018, when all borrowings and related interest were settled against amounts owed by the Company to GenOn as further discussed in Note 3 , *Acquisitions, Discontinued Operations and Dispositions*, in connection with the settlement between NRG and GenOn.

Commercial Operations Agreement

NRG Power Marketing LLC has entered into physical and financial intercompany commodity and hedging transactions with GenOn and certain of its subsidiaries. Subject to applicable collateral thresholds, these arrangements may provide for the bilateral exchange of credit support based upon market exposure and potential market movements. The terms and conditions of the agreements are generally consistent with industry practices and other third party arrangements. As of June 30, 2018, derivative assets and liabilities associated with these transactions are recorded within NRG's derivative instruments balances on the consolidated balance sheet, with related revenues and costs within operating revenues and cost of operations, respectively. Additionally, as of June 30, 2018 and December 31, 2017, the Company had $24 million and $32 million, respectively, of cash collateral posted in support of energy risk management activities by GenOn.

Note 15 — *Commitments and Contingencies*

This footnote should be read in conjunction with the complete description under Note 22, *Commitments and Contingencies*, to the Company's 2017 Form 10-K.

Commitments

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of the Company's assets, excluding assets acquired in the GenOn and EME (including Midwest Generation) acquisitions, assets held by NRG Yield, Inc. and NRG's assets that have project-level financing, to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or MWh equivalents. The Company's lien counterparties may have a claim on NRG's assets to the extent market prices exceed the hedged price. As of June 30, 2018, hedges under the first lien were in-the-money for NRG on a counterparty aggregate basis.

Contingencies

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

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

Midwest Generation Asbestos Liabilities — The Company, through its subsidiary, Midwest Generation, may be subject to potential asbestos liabilities as a result of its acquisition of EME. The Company is currently analyzing the scope of potential liability as it may relate to Midwest Generation. The Company believes that it has established an adequate reserve for these cases. On March 27, 2018, ComEd filed a Motion to Compel Payments of Claims seeking $61 million related to asbestos liabilities. On April 25, 2018, NRG filed an Omnibus Objection to All Remaining Claims of ComEd and Exelon.

Midwest Generation New Source Review Litigation — In 2009, the EPA and the Illinois Attorney General, or the Government Plaintiffs, filed a complaint in the U.S. District Court for the Northern District of Illinois alleging violations of CAA PSD requirements and opacity and PM regulations. Several environmental groups intervened as plaintiffs in this litigation. Midwest Generation moved to dismiss nine of the ten PSD counts. The trial court granted the motion in 2010. Following the trial court ruling, the Government Plaintiffs appealed the trial court's dismissals of their PSD claims. Those PSD claim dismissals were affirmed by the U.S. Court of Appeals for the Seventh Circuit in 2013. On May 10, 2018, the district court approved the Consent Decree settling this litigation and dismissed the case. Pursuant to the Consent Decree, Midwest Generation has paid $500,000 to each of the State of Illinois and the Federal Government and has agreed to make and maintain certain operational improvements.

Telephone Consumer Protection Act Purported Class Actions — Three purported class action lawsuits have been filed against NRG Residential Solar Solutions, LLC — one in California and two in New Jersey. The plaintiffs generally allege misrepresentation by the call agents and violations of the TCPA, claiming that the defendants engaged in a telemarketing campaign placing unsolicited calls to individuals on the "Do Not Call List." The plaintiffs seek statutory damages of up to $1,500 per plaintiff, actual damages and equitable relief. On June 22, 2017, plaintiffs in the California case filed a motion for leave to file a second amended complaint to substitute new plaintiffs. Defendants filed an opposition to this motion on June 26, 2017. The court granted plaintiffs' motion to substitute new plaintiffs and on August 1, 2017, defendants filed an answer to the second amended complaint. On August 31, 2017, the court in the California case agreed that the litigation should be stayed pending final court approval of the New Jersey settlement. On July 12, 2017, the parties in one of the New Jersey actions reached an agreement in principle to resolve the class allegations which was confirmed by a term sheet signed by the parties on July 28, 2017. On September 27, 2017, plaintiffs in one of the New Jersey cases filed their motion for preliminary approval of the class settlement which was approved by the court on November 17, 2017. On May 14, 2018, the court entered a final order approving the class action settlement and dismissing the lawsuit, thereby ending the New Jersey lawsuits. On July 2, 2018, the court in the California case entered an order dismissing the lawsuit.

California Department of Water Resources and San Diego Gas & Electric Company v. Sunrise Power Company LLC — On January 29, 2016, CDWR and SDG&E filed a lawsuit against Sunrise Power Company, along with NRG and Chevron Power Corporation. In June 2001, CDWR and Sunrise entered into a 10-year PPA under which Sunrise would construct and operate a generating facility and provide power to CDWR. At the time the PPA was entered into, Sunrise had a transportation services agreement, or TSA, to purchase natural gas from Kern River through April 30, 2018. In August 2003, CDWR entered into an agreement with Sunrise and Kern River in which CDWR accepted assignment of the TSA through the term of the PPA. After the PPA expired, Kern River demanded that any reassignment be to a party which met certain creditworthiness standards which Sunrise did not. As such, the plaintiffs brought this lawsuit against the defendants alleging breach of contract, breach of covenant of good faith and fair dealing and improper distributions. Plaintiffs generally claim damages of $1.2 million per month for the remaining 70 months of the TSA. On April 20, 2016, the defendants filed objections in response to the plaintiffs' complaint. The objections were granted on June 14, 2016; however, the plaintiffs were allowed to file amended complaints on July 1, 2016. On July 27, 2016, defendants filed objections to the amended complaints. On November 18, 2016, the court sustained the objections and allowed plaintiffs another opportunity to file a second amended lawsuit which they did on January 13, 2017. On April 21, 2017, the court issued an order sustaining the objections without leave to amend. On July 14, 2017, CDWR filed a notice of appeal. On January 10, 2018, CDWR filed its appellate brief. Defendants filed their opposition brief on April 10, 2018. On May 30, 2018, CDWR filed their reply brief.

Braun v. NRG Yield, Inc. — On April 19, 2016, plaintiffs filed a putative class action lawsuit against NRG Yield, Inc., the current and former members of its board of directors individually, and other parties in California Superior Court in Kern County, CA. Plaintiffs allege various violations of the Securities Act due to the defendants' alleged failure to disclose material facts related to low wind production prior to the NRG Yield, Inc.'s June 22, 2015 Class C common stock offering. Plaintiffs seek compensatory damages, rescission, attorney's fees and costs. The Defendants filed demurrers and a motion challenging jurisdiction on October 18, 2016. On July 30, 2018, the plaintiffs filed an opposition to the defendants' motion to quash service of the summons and an opposition to the defendants' demurrer.

Griffoul v. NRG Residential Solar Solutions — On February 28, 2017, plaintiffs, consisting of New Jersey residential solar customers, filed a purported class action lawsuit in New Jersey state court. Plaintiffs allege violations of the New Jersey Consumer Fraud Action and Truth-in-Consumer Contracts, Warranty and Notice Act with regard to certain provisions of their residential solar contracts. The plaintiffs seek damages and injunctive relief as to the proper allocation of the solar renewable energy credits. On June 6, 2017, the defendants filed a motion to compel arbitration or dismiss the lawsuit. Plaintiffs filed their opposition on June 29, 2017. On July 14, 2017, the court denied NRG's motion to compel arbitration or dismiss the case. On July 25, 2017, NRG filed a motion for reconsideration of the appeal, which was denied. On August 22, 2017, NRG filed a notice of appeal. After oral argument on April 24, 2018, the Appellate Division reversed the lower court on May 4, 2018, and ordered that the plaintiff must arbitrate their claims against NRG. On May 23, 2018, the plaintiff filed a petition for certification with the Supreme Court of New Jersey seeking to overturn the Appellate Division ruling. The petition and objection are fully briefed.

Rice v. NRG — On April 14, 2017, plaintiffs filed a purported class action lawsuit in the U.S. District Court for the Western District of Pennsylvania against NRG, First Energy Corporation and Matt Canastrale Contracting, Inc. Plaintiffs generally claim personal injury, trespass, nuisance and property damage related to the disposal of coal ash from GenOn's Elrama Power Plant and First Energy's Mitchell and Hatfield Power Plants. Plaintiffs generally seek monetary damages, medical monitoring and remediation of their property. Plaintiffs filed an amended complaint on August 14, 2017. On October 20, 2017, NRG filed its answers and affirmative defenses. On July 6, 2018, NRG filed a motion for summary judgment. Plaintiffs filed their opposition to the motion for summary judgment on July 29, 2018.

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. On September 14, 2017, the court issued a scheduling order setting this case for trial on October 21, 2019. LaGen filed its answer and affirmative defenses on November 17, 2017.

GenOn Chapter 11 Cases — On the Petition Date, the GenOn Entities filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. Under the Restructuring Support Agreement to which the GenOn Entities, NRG and certain of GenOn's and GenOn Americas Generation's senior unsecured noteholders are parties, each of them supported the Bankruptcy Court's approval of the plan of reorganization. GenOn has a customary "fiduciary out" under the Restructuring Support Agreement. If the plan of reorganization is not consummated, NRG may not be entitled to the benefits of the Settlement Agreement provided under the Restructuring Support Agreement and it will remain subject to any claims of GenOn and the noteholders, including claims relating to or arising out of any shared services and any other relationships or transactions between the companies. See Note 3, *Acquisitions*, *Discontinued Operations and Dispositions*, for additional information related to the Chapter 11 Cases.

GenOn Noteholders' Lawsuit — On December 13, 2016, certain indenture trustees for an ad hoc group of holders, or the Noteholders, of the GenOn Energy, Inc. 7.875% Senior Notes due 2017, 9.500% Notes due 2018, and 9.875% Notes due 2020, and the GenOn Americas Generation, LLC 8.50% Senior Notes due 2021 and 9.125% Senior Notes due 2031, along with certain of the Noteholders, filed a complaint in the Superior Court of the State of Delaware against NRG and GenOn alleging certain claims related to the Services Agreement between NRG and GenOn. Plaintiffs generally seek return of all monies paid under the Services Agreement and any other damages that the court deems appropriate. On February 3, 2017, the court entered an order approving a Standstill Agreement whereby the parties agreed to suspend all deadlines in the case until March 1, 2017. The Standstill Agreement terminated on March 1, 2017. On April 30, 2017, the Noteholders filed an amended complaint that asserts (i) additional fraudulent transfer claims in relation to GenOn’s sale of the Marsh Landing project to NRG Yield LLC, (ii) alleged breaches of fiduciary duty by certain current and former officers and directors of GenOn in relation to the Services Agreement and the alleged usurpation of corporate opportunities concerning the Mandalay and Canal projects and (iii) claims against NRG for allegedly aiding and abetting such claimed breaches of fiduciary duties. In addition to NRG and GenOn, the amended complaint names NRG Yield LLC and certain current and former officers and directors of GenOn as defendants. The plaintiffs, among other things, generally seek return of all monies paid under the services agreement and any other damages that the court deems appropriate. On July 13, 2018, NRG and GenOn executed a term sheet that resolves and releases the GenOn Noteholder litigation.

Morgantown v. GenOn Mid-Atlantic — On June 8, 2017, Morgantown and Dickerson Owner Lessors filed a lawsuit against GenOn Mid-Atlantic, LLC, NRG North America LLC, GenOn Americas Generation, LLC, NRG Americas, Inc., GenOn Energy Holdings, Inc., GenOn Energy, Inc., and NRG Energy, Inc. in New York State Supreme Court. The plaintiffs allege that they were overcharged by defendants for certain services outlined in a Services Agreement and that defendants caused a Qualified Credit Support portion of a Participation Agreement, or QCS Agreement, to be violated by causing the transfer of certain money outside the allowable confines set forth in the QCS Agreement. In addition, plaintiffs claim that the transfers were unfairly executed and done so in an effort to defraud plaintiffs and hinder their ability to continue to do business. As such, plaintiffs seek, among other things, the return of certain transferred funds and service charges paid and to bar defendants from executing additional transfers on plaintiffs’ behalf. On November 7, 2017, the Bankruptcy Court issued an order estimating the claims to be valued at $0. On December 14, 2017, a settlement agreement was executed between GenOn and NRG. On April 27, 2018, the parties executed a mutual release which in conjunction with the settlement agreement resolved this lawsuit.

BTEC v. NRG Texas Power — On July 18, 2017, BTEC New Albany LLC, or BTEC, filed a lawsuit against NRG Texas Power LLC, or NRG Texas Power, in the Harris County District Court in Texas. On January 15, 2013, the parties entered into a Membership Interest and Purchase Agreement, or MIPA, whereby BTEC agreed to dismantle, transport and rebuild an electric power generation facility at the former P.H. Robinson Electric Generating Station in Bacliff, Texas. The MIPA required BTEC to meet a Guaranteed Commercial Completion Date of May 31, 2016. Because BTEC had not satisfied all of the contractually-required acceptance criteria by the MIPA expiration date, NRG elected to terminate the contract in June 2017. BTEC claimed that NRG Texas Power breached the MIPA by improperly terminating it, and sought a declaratory judgment as to the rights and obligations of the parties as well as damages, interest and attorney’s fees. On September 7, 2017, NRG Texas Power filed a counterclaim seeking damages in excess of $48 million. On June 7, 2018, the parties resolved all claims and counterclaims in the lawsuit and a dismissal order was subsequently entered by the court on July 12, 2018.

GenOn Related Contingencies

Actions Pursued by MC Asset Recovery — With Mirant Corporation's emergence from bankruptcy protection in 2006, certain actions filed by GenOn Energy Holdings and some of its subsidiaries against third parties were transferred to MC Asset Recovery, a wholly owned subsidiary of GenOn Energy Holdings. MC Asset Recovery is governed by a manager who is independent of NRG and GenOn. MC Asset Recovery is a disregarded entity for income tax purposes. Under the remaining action transferred to MC Asset Recovery, MC Asset Recovery sought to recover damages from Commerzbank AG and various other banks, or the Commerzbank Defendants, for alleged fraudulent transfers that occurred prior to Mirant's bankruptcy proceedings. In December 2010, the U.S. District Court for the Northern District of Texas dismissed MC Asset Recovery's complaint against the Commerzbank Defendants. In January 2011, MC Asset Recovery appealed the District Court's dismissal of its complaint against the Commerzbank Defendants to the U.S. Court of Appeals for the Fifth Circuit, or the Fifth Circuit. In March 2012, the Fifth Circuit reversed the District Court's dismissal and reinstated MC Asset Recovery's amended complaint against the Commerzbank Defendants. On December 10, 2015, the District Court granted summary judgment in favor of the Commerzbank Defendants. On December 29, 2015, MC Asset Recovery filed a notice to appeal this judgment with the Fifth Circuit. On June 1, 2017, the Fifth Circuit affirmed the District Court's judgment. On June 12, 2017, MC Asset Recovery petitioned the Fifth Circuit for rehearing. The petition for rehearing was denied and a court order and judgment affirming the District Court's judgments was entered on July 17, 2017. On October 17, 2018, the bankruptcy court is scheduled to hear a Motion for a Final Decree to close the Mirant bankruptcy case.

Natural Gas Litigation — GenOn has been a party to several lawsuits, certain of which are class action lawsuits, in state and federal courts, of which four remain pending involving plaintiffs in Kansas, Missouri and Wisconsin. These lawsuits were filed in the aftermath of the California energy crisis in 2000 and 2001 and the resulting FERC investigations and relate to alleged conduct to increase natural gas prices in violation of state antitrust law and similar laws. The lawsuits seek treble or punitive damages, restitution and/or expenses. The lawsuits also name as parties a number of energy companies unaffiliated with NRG. In July 2011, the U.S. District Court for the District of Nevada, which was handling four of the five cases, granted the defendants' motion for summary judgment and dismissed all claims against GenOn in those cases. The plaintiffs appealed to the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit, which reversed the decision of the District Court. GenOn along with the other defendants in the lawsuit filed a petition for a writ of certiorari to the U.S. Supreme Court challenging the Ninth Circuit's decision and the U.S. Supreme Court granted the petition. On April 21, 2015, the U.S. Supreme Court affirmed the Ninth Circuit's holding that plaintiffs' state antitrust law claims are not field-preempted by the federal Natural Gas Act and the Supremacy Clause of the U.S. Constitution. The U.S. Supreme Court left open whether the claims were preempted on the basis of conflict preemption. The U.S. Supreme Court directed that the case be remanded to the U.S. District Court for the District of Nevada for further proceedings.

On March 7, 2016, class plaintiffs filed their motions for class certification. On March 30, 2017, the court denied the plaintiffs' motions for class certification, which the plaintiffs appealed to. The plaintiffs petitioned the Ninth Circuit for interlocutory review. On July 12, 2018, the Ninth Circuit heard oral arguments and the case is under submission pending a decision.

On February 26, 2018, GenOn filed objections to the proofs of claim filed in the Chapter 11 Cases by all of the plaintiffs in each of the four cases. GenOn filed that same day a motion asking the Bankruptcy Court to estimate all of the proofs of claim at zero dollars, to which the plaintiffs objected. The Bankruptcy Court denied the plaintiffs' objection, ruling that it had the authority to consider GenOn's objections to the proofs of claim and to estimate the claims, but has certified its decision for review by either the Fifth Circuit Court of Appeals or the District Court.

In June 2018, GenOn reached a settlement with plaintiffs in three of the four remaining suits, which leaves only the one purported class action involving plaintiffs in Wisconsin. CenterPoint Energy Services is a defendant in that case, and GenOn has agreed to indemnify CenterPoint against certain losses relating to the lawsuit. The Nevada District Judge granted summary judgment in favor of CenterPoint in that lawsuit and the plaintiffs appealed that decision to the Ninth Circuit. The appeal was argued on February 16, 2018, and the case is under submission pending a decision.

Mirant Chapter 11 Proceedings — In July 2003, and various dates thereafter, the Mirant Debtors filed voluntary petitions in the U.S. Bankruptcy Court for the Northern District of Texas, Fort Worth Division, for relief under Chapter 11 of the Bankruptcy Code. GenOn Energy Holdings and most of the other Mirant Debtors emerged from bankruptcy on January 3, 2006, when the plan of reorganization that was approved in conjunction with Mirant Corporation's emergence from bankruptcy protection, or the Mirant Plan, became effective. The remaining Mirant Debtors emerged from bankruptcy on various dates in 2007. Approximately 461,000 of the shares of GenOn Energy Holdings common stock to be distributed under the Mirant Plan have not yet been distributed and have been reserved for distribution with respect to claims disputed by the Mirant Debtors that have not been resolved. Upon the Mirant/RRI Merger, those reserved shares converted into a reserve for approximately 1.3 million shares of GenOn common stock. Upon the NRG Merger, those reserved shares converted into a reserve for approximately 159,000 shares of NRG common stock. Under the terms of the Mirant Plan, upon the resolution of such a disputed claim, the claimant will receive the same pro rata distributions of common stock, cash, or both as previously allowed claims, regardless of the price at which the common stock is trading at the time the claim is resolved. If the aggregate amount of any such payouts results in the number of reserved shares being insufficient, additional shares of common stock may be issued to address the shortfall. The bankruptcy court is scheduled to hear a Motion for a Final Decree in the Mirant bankruptcy on October 17, 2018.

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

Natixis v. GenOn Mid-Atlantic — On February 16, 2018, Natixis Funding Corp. and Natixis, New York Branch filed a complaint in the Supreme Court of the State of New York against GenOn Mid-Atlantic, the owner lessors under GenOn Mid-Atlantic's operating leases of the Dickerson and Morgantown coal generation units, and the lease indenture trustee under those leases. The plaintiffs' allegations against GenOn Mid-Atlantic relate to a payment agreement between GenOn Mid-Atlantic and Natixis Funding Corp. to procure credit support for the payment of certain lease payments owed pursuant to the GenOn Mid-Atlantic operating leases for Morgantown and Dickerson. The plaintiffs seek approximately $34 million in damages arising from GenOn Mid-Atlantic's purported breach of certain warranties in the payment agreement. On April 2, 2018, GenOn Mid-Atlantic removed the allegations against it to the U.S. District Court for the Southern District of New York. On April 11, 2018, the U.S. District Court for the Southern District of New York entered a briefing schedule on a forthcoming motion to remand by Natixis Funding Corp. and a forthcoming motion to transfer by GenOn Mid-Atlantic. On April 26, 2018, Natixis Funding Corp. filed its motion to remand. On May 31, 2018, GenOn Mid-Atlantic opposed the motion to remand and filed a cross-motion to transfer. The parties completed briefing on the motions to remand and transfer on July 9, 2018, and the U.S. District Court for the Southern District of New York held an oral argument on July 18, 2018 and continued the motions to a subsequent conference scheduled for September 26, 2018.

Note 16 — *Regulatory Matters*

This footnote should be read in conjunction with the complete description under Note 23, *Regulatory Matters*, to the Company's 2017 Form 10-K. Environmental regulatory matters are discussed within Note 17, *Environmental Matters*, to this Form 10-Q.

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

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

National

Department of Energy Consideration of 202(c) and Defense Production Act — On March 29, 2018, FirstEnergy Solutions requested that the Department of Energy provide price supports for its coal and nuclear units by having the DOE issue an emergency must-run order under Section 202(c) of the Federal Power Act. A number of parties have filed comments with the DOE, including PJM, challenging the assertion that the FirstEnergy Solutions' units are necessary for grid reliability. The DOE has not yet formally responded. On June 1, 2018, the White House announced that President Trump has directed Secretary of Energy Rick Perry to "prepare immediate steps to stop the loss" of coal and nuclear resources. No formal timeline for action on either proposal has been set by the Administration.

Zero-Emission Credits for Nuclear Plants in Illinois — In 2016, Illinois enacted a Zero Emission Credit, or ZEC, program for selected nuclear units in Illinois. In total, the program directs over $2.5 billion over ten years to two Exelon-owned nuclear power plants in Illinois. These ZECs are out-of-market subsidies that threaten to artificially suppress market prices and interfere with the wholesale power market. On February 14, 2017, NRG, along with other companies, filed a complaint in the U.S. District Court for the Northern District of Illinois alleging that the state program is preempted by federal law and in violation of the dormant commerce clause. On July 14, 2017, Defendants' motions to dismiss were granted. On July 17, 2017, NRG, along with other companies, filed a notice of appeal to the U.S. Court of Appeals for the Seventh Circuit. Briefing is complete. On May 29, 2018, the United States filed an amicus brief at the invitation of the Seventh Circuit arguing that the ZEC program is not preempted.

Zero-Emission Credits for Nuclear Plants in New York — On August 1, 2016, the NYSPSC issued its Clean Energy Standard, or CES, which provided for ZECs which would provide more than $7.6 billion over 12 years in out-of-market subsidy payments to certain selected nuclear generating units in the state. These ZECs are out-of-market subsidies that threaten to artificially suppress market prices and interfere with the wholesale power market. On October 19, 2016, NRG, along with other companies, filed a complaint in the U.S. District Court for the Southern District of New York, challenging the validity of the NYSPSC action and the ZEC program. On July 25, 2017, Defendants' motions to dismiss were granted. On August 24, 2017, NRG, along with other plaintiff companies, filed a notice of appeal to the U.S. Court of Appeals for the Second Circuit. Briefing is complete. On May 29, 2018, the United States filed an amicus brief at the invitation of the Seventh Circuit arguing that the ZEC program is not preempted.

Department of Energy's Proposed Grid Resiliency Pricing Rule and Subsequent FERC Proceeding — On September 29, 2017, the Department of Energy issued a proposed rulemaking titled the "Grid Resiliency Pricing Rule." The rulemaking directs FERC to take action to reform the ISO/RTO markets to value certain reliability and resiliency attributes of electric generation resources. On October 2, 2017, FERC issued a notice inviting comments. On October 4, 2017, FERC staff issued a series of questions requesting commenters to address. On October 23, 2017, NRG filed comments encouraging FERC to act expeditiously to modernize energy and capacity markets in a manner compatible with robust competitive markets. On January 8, 2018, FERC terminated the proposed rulemaking and opened a new proceeding asking each ISO/RTO to address specific questions focused on grid resilience. On March 9, 2018, the ISOs/RTOs filed comments to the questions posed by FERC. The Company responded on May 9, 2018 and is currently awaiting a decision from FERC.

East/West

Montgomery County Station Power Tax — On December 20, 2013, NRG received a letter from Montgomery County, Maryland requesting payment of an energy tax for the consumption of station power at the Dickerson Facility over the previous three years. Montgomery County seeks payment in the amount of $22 million, which includes tax, interest and penalties. NRG disputed the applicability of the tax. On December 11, 2015, the Maryland Tax Court reversed Montgomery County's assessment. Montgomery County filed an appeal, and on February 2, 2017, the Montgomery County Circuit Court affirmed the decision of the tax court. On February 17, 2017, Montgomery County filed an appeal to the Court of Special Appeals of Maryland. On April 24, 2018, the Court of Special Appeals of Maryland affirmed the lower court's decision and on May 29, 2018, Montgomery County petitioned the Court of Appeals of Maryland to issue a writ of certiorari to review that decision. NRG filed an answer opposing the petition on June 18, 2018. The petition is currently pending before the Court of Appeals of Maryland.

Puente Power Project — On October 5, 2017, the California Energy Commission, or CEC, the agency responsible for permitting the Puente Power Project, issued a statement on behalf of the committee of two Commissioners overseeing the permitting process stating their intention to issue a proposed decision that would deny a permit for the Puente Power Project. On October 16, 2017, NRG filed a motion to suspend the permitting proceeding for at least six months, which was granted on November 3, 2017. On May 31, 2018, the CEC extended the suspension period at NRG's request to July 1, 2019. The supplemental extension period should allow sufficient time to determine whether alternate procurement efforts undertaken by SCE supersede the need for the Puente Power Project.

Note 17 — *Environmental Matters*

This footnote should be read in conjunction with the complete description under Note 24, *Environmental Matters*, to the Company's 2017 Form 10-K.

NRG is subject to a wide range of environmental laws in the development, construction, ownership and operation of projects. These laws generally require that governmental permits and approvals be obtained before construction and during operation of power plants. NRG is also subject to laws regarding the protection of wildlife, including migratory birds, eagles and threatened and endangered species. 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.

The EPA finalized CSAPR in 2011, which was intended to replace CAIR in January 2012, to address certain states' obligations to reduce emissions so that downwind states can achieve federal air quality standards. In December 2011, the D.C. Circuit stayed the implementation of CSAPR and then vacated CSAPR in August 2012 but kept CAIR in place until the EPA could replace it. In April 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit's decision. In October 2014, the D.C. Circuit lifted the stay of CSAPR. In response, the EPA in November 2014 amended the CSAPR compliance dates. Accordingly, CSAPR replaced CAIR on January 1, 2015. On July 28, 2015, the D.C. Circuit held that the EPA had exceeded its authority by requiring certain reductions that were not necessary for downwind states to achieve federal standards. Although the D.C. Circuit kept the rule in place, the court ordered the EPA to revise the Phase 2 (or 2017) (i) SO_2 budgets for four states including Texas and (ii) ozone-season NOx budgets for 11 states including Maryland, New Jersey, New York, Ohio, Pennsylvania and Texas. On October 26, 2016, the EPA finalized the CSAPR Update Rule, which reduces future NOx allocations and discounts the current banked allowances to account for the more stringent 2008 Ozone NAAQS and to address the D.C. Circuit's July 2015 decision. This rule has been challenged in the D.C. Circuit. The Company believes its investment in pollution controls and cleaner technologies leave the fleet well-positioned for compliance.

In February 2012, the EPA promulgated standards (the MATS rule) to control emissions of HAPs from coal and oil-fired electric generating units. The rule established limits for mercury, non-mercury metals, certain organics and acid gases, which had to be met beginning in April 2015 (with some units getting a 1-year extension). In June 2015, the U.S. Supreme Court issued a decision in the case of Michigan v. EPA, and held that the EPA unreasonably refused to consider costs when it determined that it was "appropriate and necessary" to regulate HAPs emitted by electric generating units. The U.S. Supreme Court did not vacate the MATS rule but rather remanded it to the D.C. Circuit for further proceedings. In December 2015, the D.C. Circuit remanded the MATS rule to the EPA without vacatur. On April 25, 2016, the EPA released a supplemental finding that the benefits of this regulation outweigh the costs to address the U.S. Supreme Court's ruling that the EPA had not properly considered costs. This finding has been challenged in the D.C. Circuit. On April 18, 2017, the EPA asked the D.C. Circuit to postpone oral argument that had been scheduled for May 18, 2017 because the EPA is closely reviewing the supplemental finding to determine whether it should reconsider all or part of the rule. On April 27, 2017, the D.C. Circuit granted EPA's request to postpone the oral argument and hold the case in abeyance. While NRG cannot predict the final outcome of this rulemaking, NRG believes that because it has already invested in pollution controls and cleaner technologies, the fleet is well-positioned to comply with the MATS rule.

Water

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

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

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. The EPA has stated that it intends to further revise the rule.

East/West

New Source Review — The EPA and various states have been investigating compliance of electric generating facilities with the pre-construction permitting requirements of the CAA known as "new source review," or NSR. In 2007, Midwest Generation received an NOV from the EPA alleging that past work at Crawford, Fisk, Joliet, Powerton, Waukegan and Will County generating stations violated NSR and other regulations. These alleged violations are the subject of litigation described in Note 15, *Commitments and Contingencies.* Additionally, in April 2013, the Connecticut Department of Energy and Environmental Protection issued four NOVs alleging that past work at oil-fired combustion turbines at the Torrington Terminal, Franklin, Branford and Middletown generating stations violated regulations regarding NSR.

Note 18 — *Condensed Consolidating Financial Information*

As of June 30, 2018, the Company had outstanding $5.4 billion of Senior Notes due from 2022 to 2048, as shown in Note 8, *Debt and Capital Leases*. These Senior Notes are guaranteed by certain of NRG's current and future 100% owned domestic subsidiaries, or guarantor subsidiaries. These guarantees are both joint and several. The non-guarantor subsidiaries include all of NRG's foreign subsidiaries and certain domestic subsidiaries, and NRG Yield, Inc. and its subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of June 30, 2018:

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

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. However, 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 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.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the three months ended June 30, 2018

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Operating Revenues					
Total operating revenues	$ 2,276	$ 659	$ —	$ (13)	$ 2,922
Operating Costs and Expenses					
Cost of operations	1,778	282	(4)	(5)	2,051
Depreciation and amortization	76	143	8	—	227
Impairment losses	—	74	—	—	74
Selling, general and administrative	110	34	77	(10)	211
Reorganization costs	1	—	22	—	23
Development costs	—	13	3	—	16
Total operating costs and expenses	1,965	546	106	(15)	2,602
Gain on sale of assets	—	14	—	—	14
Operating Income/(Loss)	311	127	(106)	2	334
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	7	—	355	(362)	—
Equity in earnings of unconsolidated affiliates	—	18	—	—	18
Other income/(expense), net	4	(26)	2	—	(20)
Loss on debt extinguishment, net	—	—	(1)	—	(1)
Interest expense	(4)	(92)	(106)	—	(202)
Total other income/(expense)	7	(100)	250	(362)	(205)
Income Before Income Taxes	318	27	144	(360)	129
Income tax expense/(benefit)	108	(68)	(32)	—	8
Income from Continuing Operations	210	95	176	(360)	121
Loss from discontinued operations, net of income tax	—	—	(25)	—	(25)
Net Income	210	95	151	(360)	96
Less: Net (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interests	—	(57)	79	2	24
Net Income Attributable to NRG Energy, Inc.	$ 210	$ 152	$ 72	$ (362)	$ 72

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the six months ended June 30, 2018

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Operating Revenues					
Total operating revenues	$ 4,120	$ 1,249	$ —	$ (26)	$ 5,343
Operating Costs and Expenses					
Cost of operations	3,004	613	9	(17)	3,609
Depreciation and amortization	149	297	16	—	462
Impairment losses	—	74	—	—	74
Selling, general and administrative	213	60	139	(10)	402
Reorganization costs	3	—	40	—	43
Development costs	—	23	7	(1)	29
Total operating costs and expenses	3,369	1,067	211	(28)	4,619
Gain on sale of assets	3	13	—	—	16
Operating Income/(Loss)	754	195	(211)	2	740
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	9	—	685	(694)	—
Equity in earnings/(losses) of unconsolidated affiliates	—	17	(1)	—	16
Other income/(expense), net	8	(36)	5	—	(23)
Loss on debt extinguishment, net	—	—	(3)	—	(3)
Interest expense	(7)	(164)	(198)	—	(369)
Total other income/(expense)	10	(183)	488	(694)	(379)
Income Before Income Taxes	764	12	277	(692)	361
Income tax expense/(benefit)	221	(20)	(194)	—	7
Income from Continuing Operations	543	32	471	(692)	354
Loss from discontinued operations, net of income tax	—	—	(25)	—	(25)
Net Income	543	32	446	(692)	329
Less: Net (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interests	—	(119)	95	2	(22)
Net Income Attributable to NRG Energy, Inc.	$ 543	$ 151	$ 351	$ (694)	$ 351

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

For the three months ended June 30, 2018

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Net Income	$ 210	$ 95	$ 151	$ (360)	$ 96
Other Comprehensive Income, net of tax					
Unrealized gain on derivatives, net	—	4	6	(5)	5
Foreign currency translation adjustments, net	(4)	(4)	(5)	9	(4)
Available-for-sale securities, net	—	—	1	—	1
Defined benefit plans, net	—	—	(1)	—	(1)
Other comprehensive (loss)/income	(4)	—	1	4	1
Comprehensive Income	206	95	152	(356)	97
Less: Comprehensive (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interest	—	(57)	81	2	26
Comprehensive Income Attributable to NRG Energy, Inc.	$ 206	$ 152	$ 71	$ (358)	$ 71

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

For the six months ended June 30, 2018

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Net Income	$ 543	$ 32	$ 446	$ (692)	$ 329
Other Comprehensive (Loss)/Income, net of tax					
Unrealized gain on derivatives, net	—	20	21	(22)	19
Foreign currency translation adjustments, net	(6)	(6)	(8)	14	(6)
Available-for-sale securities, net	—	—	1	—	1
Defined benefit plans, net	—	—	(2)	—	(2)
Other comprehensive (loss)/income	(6)	14	12	(8)	12
Comprehensive Income	537	46	458	(700)	341
Less: Comprehensive (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interest	—	(119)	105	2	(12)
Comprehensive Income Attributable to NRG Energy, Inc.	$ 537	$ 165	$ 353	$ (702)	$ 353

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
June 30, 2018
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated
ASSETS			(In millions)		
Current Assets					
Cash and cash equivalents	$ 71	$ 395	$ 514	$ —	$ 980
Funds deposited by counterparties	71	—	—	—	71
Restricted cash	9	277	—	—	286
Accounts receivable, net	1,094	274	3	—	1,371
Inventory	309	176	—	—	485
Derivative instruments	837	36	15	(37)	851
Cash collateral paid in support of energy risk management activities	209	15	—	—	224
Accounts receivable - affiliate	1,189	123	141	(1,396)	57
Current assets - held for sale	—	100	—	—	100
Prepayments and other current assets	173	122	35	(2)	328
Total current assets	3,962	1,518	708	(1,435)	4,753
Property, plant and equipment, net	2,402	10,164	231	(23)	12,774
Other Assets					
Investment in subsidiaries	486	—	8,111	(8,597)	—
Equity investments in affiliates	—	1,055	—	—	1,055
Notes receivable, less current portion	—	15	—	—	15
Goodwill	360	179	—	—	539
Intangible assets, net	415	1,448	—	(3)	1,860
Nuclear decommissioning trust fund	694	—	—	—	694
Derivative instruments	329	61	38	(2)	426
Deferred income tax	156	34	(64)	—	126
Non-current assets held-for-sale	—	50	—	—	50
Other non-current assets	81	454	120	—	655
Total other assets	2,521	3,296	8,205	(8,602)	5,420
Total Assets	$ 8,885	$ 14,978	$ 9,144	$ (10,060)	$ 22,947
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ —	$ 862	$ 92	$ (2)	$ 952
Accounts payable	699	230	46	—	975
Accounts payable — affiliate	1,901	(207)	(269)	(1,396)	29
Derivative instruments	695	51	—	(37)	709
Cash collateral received in support of energy risk management activities	72	—	—	—	72
Current liabilities held-for-sale	—	74	—	—	74
Accrued expenses and other current liabilities	270	123	326	—	719
Accrued expenses and other current liabilities-affiliate	—	—	133	—	133
Total current liabilities	3,637	1,133	328	(1,435)	3,663
Other Liabilities					
Long-term debt and capital leases	245	7,428	7,148	—	14,821
Nuclear decommissioning reserve	274	—	—	—	274
Nuclear decommissioning trust liability	410	—	—	—	410
Deferred income taxes	112	64	(159)	—	17
Derivative instruments	237	50	—	(2)	285
Out-of-market contracts, net	58	137	—	—	195
Non-current liabilities held-for-sale	—	12	—	—	12
Other non-current liabilities	410	311	409	—	1,130
Total non-current liabilities	1,746	8,002	7,398	(2)	17,144
Total liabilities	5,383	9,135	7,726	(1,437)	20,807
Redeemable noncontrolling interest in subsidiaries	—	69	—	—	69
Stockholders' Equity	3,502	5,774	1,418	(8,623)	2,071

Total Liabilities and Stockholders’ Equity	$ 8,885	$ 14,978	$ 9,144	$ (10,060)	$ 22,947

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

NRG ENERGY, INC. AND SUBSIDIARIES CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the six months ended June 30, 2018
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 543	$ 32	$ 446	$ (692)	$ 329
Loss from discontinued operations	—	—	(25)	—	(25)
Net income from continuing operations	543	32	471	(692)	354
Adjustments to reconcile net income to net cash provided/(used) by operating activities:					
Distributions from unconsolidated affiliates	—	50	—	(7)	43
Equity in (earnings)/losses of unconsolidated affiliates	—	(17)	1	—	(16)
Depreciation, amortization and accretion	162	307	16	—	485
Provision for bad debts	31	—	—	—	31
Amortization of nuclear fuel	24	—	—	—	24
Amortization of financing costs and debt discount/premiums	—	18	9	—	27
Adjustment for debt extinguishment	—	—	3	—	3
Amortization of intangibles and out-of-market contracts	9	39	—	—	48
Amortization of unearned equity compensation	—	—	26	—	26
Impairment losses	—	89	—	—	89
Changes in deferred income taxes and liability for uncertain tax benefits	221	(41)	(176)	—	4
Changes in nuclear decommissioning trust liability	41	—	—	—	41
Changes in derivative instruments	(154)	(43)	8	(22)	(211)
Changes in collateral deposits in support of energy risk management activities	(4)	(14)	—	—	(18)
Gain on sale of emission allowances	(11)	—	—	—	(11)
Gain on sale of assets	(3)	(13)	—	—	(16)
Loss on deconsolidation of business	—	22	—	—	22
Changes in other working capital	(298)	41	(865)	721	(401)
Net Cash Provided/(Used) by Operating Activities	561	470	(507)	—	524
Cash Flows from Investing Activities					
Dividends from NRG Yield, Inc.	—	—	52	(52)	—
Acquisition of Drop Down Assets, net of cash acquired	—	(126)	—	126	—
Acquisition of business, net of cash acquired	(2)	(282)	—	—	(284)
Capital expenditures	(105)	(556)	(30)	—	(691)
Decrease in notes receivable	—	4	—	—	4
Purchases of emission allowances	(22)	—	—	—	(22)
Proceeds from sale of emission allowances	34	—	—	—	34
Investments in nuclear decommissioning trust fund securities	(346)	—	—	—	(346)
Proceeds from the sale of nuclear decommissioning trust fund securities	303	—	—	—	303
Proceeds from sale of assets, net of cash disposed of	10	8	—	—	18
Deconsolidation of business	—	(160)	—	—	(160)
Change in investments in unconsolidated affiliates	—	(2)	—	—	(2)
Net Cash (Used)/Provided by Investing Activities	(128)	(1,114)	22	74	(1,146)
Cash Flows from Financing Activities					
Dividends from NRG Yield, Inc.	—	(52)	—	52	—
Payment (for)/from intercompany loans	(323)	108	215	—	—
Acquisition of Drop Down Assets, net of cash acquired	—	—	126	(126)	—
Payment of dividends to common and preferred stockholders	—	—	(19)	—	(19)
Payment for treasury stock	—	—	(500)	—	(500)
Proceeds from issuance of long-term debt	—	774	831	—	1,605
Payments for short and long-term debt	—	(564)	(284)	—	(848)
Contributions from, net of distributions to noncontrolling interests in subsidiaries	—	222	—	—	222
Payment of debt issuance costs	—	(24)	(13)	—	(37)
Net Cash (Used)/Provided by Financing Activities	(323)	464	356	(74)	423
Net Increase/(Decrease) in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash	110	(180)	(129)	—	(199)
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period	41	852	643	—	1,536

Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period	$ 151	$ 672	$ 514	$ —	$ 1,337

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the three months ended June 30, 2017

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Operating Revenues					
Total operating revenues	$ 2,060	$ 664	$ —	$ (23)	$ 2,701
Operating Costs and Expenses					
Cost of operations	1,530	312	20	(21)	1,841
Depreciation and amortization	99	153	8	—	260
Impairment losses	42	21	—	—	63
Selling, general and administrative	96	29	97	(1)	221
Development costs	—	13	5	—	18
Total operating costs and expenses	1,767	528	130	(22)	2,403
Other income - affiliate	—	—	39	—	39
Gain on sale of assets	2	—	—	—	2
Operating Income/(Loss)	295	136	(91)	(1)	339
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	8	—	(149)	141	—
Equity in losses of unconsolidated affiliates	—	(2)	(1)	—	(3)
Other income, net	—	41	7	(34)	14
Interest expense	(4)	(121)	(122)	—	(247)
Total other income/(expense)	4	(82)	(265)	107	(236)
Income/(Loss) from Continuing Operations Before Income Taxes	299	54	(356)	106	103
Income tax expense/(benefit)	113	267	(376)	—	4
Income/(Loss) from Continuing Operations	186	(213)	20	106	99
Loss from discontinued operations, net of income tax	—	(123)	(618)	—	(741)
Net Income/(Loss)	186	(336)	(598)	106	(642)
Less: Net (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interest	—	(9)	28	(35)	(16)
Net Income/(Loss) Attributable to NRG Energy, Inc.	$ 186	$ (327)	$ (626)	$ 141	$ (626)

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For the six months ended June 30, 2017

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Operating Revenues					
Total operating revenues	$ 3,878	$ 1,241	$ —	$ (36)	$ 5,083
Operating Costs and Expenses					
Cost of operations	3,050	651	39	(36)	3,704
Depreciation and amortization	198	303	16	—	517
Impairment losses	42	21	—	—	63
Selling, general and administrative	205	64	213	(1)	481
Development costs	—	25	10	—	35
Total operating costs and expenses	3,495	1,064	278	(37)	4,800
Other income - affiliate	—	—	87	—	87
Gain on sale of assets	4	—	—	—	4
Operating Income/(Loss)	387	177	(191)	1	374
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	13	—	(100)	87	—
Equity in earnings/(losses) of unconsolidated affiliates	—	4	(2)	—	2
Other income, net	1	47	13	(35)	26
Loss on debt extinguishment, net	—	(2)	—	—	(2)
Interest expense	(7)	(225)	(239)	—	(471)
Total other income/(expense)	7	(176)	(328)	52	(445)
Income/(Loss) from Continuing Operations Before Income Taxes	394	1	(519)	53	(71)
Income tax expense/(benefit)	131	237	(369)	—	(1)
Income/(Loss) from Continuing Operations	263	(236)	(150)	53	(70)
Loss from discontinued operations, net of income tax	—	(160)	(615)	—	(775)
Net Income/(Loss)	263	(396)	(765)	53	(845)
Less: Net (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interest	—	(46)	25	(34)	(55)
Net Income/(Loss) Attributable to NRG Energy, Inc.	$ 263	$ (350)	$ (790)	$ 87	$ (790)

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

For the three months ended June 30, 2017

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated
			(In millions)		
Net Income/(Loss)	$ 186	$ (336)	$ (598)	$ 106	$ (642)
Other Comprehensive Income, net of tax					
Unrealized loss on derivatives, net	—	(6)	(4)	5	(5)
Foreign currency translation adjustments, net	—	1	—	—	1
Available-for-sale securities, net	—	—	1	—	1
Defined benefit plans, net	—	28	28	(29)	27
Other comprehensive income	—	23	25	(24)	24
Comprehensive Income/(Loss)	186	(313)	(573)	82	(618)
Less: Comprehensive (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interest	—	(10)	28	(35)	(17)
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	$ 186	$ (303)	$ (601)	$ 117	$ (601)

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

For the six months ended June 30, 2017

(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated
			(In millions)		
Net Income/(Loss)	$ 263	$ (396)	$ (765)	$ 53	$ (845)
Other Comprehensive Income, net of tax					
Unrealized loss on derivatives, net	—	(1)	—	—	(1)
Foreign currency translation adjustments, net	5	5	7	(9)	8
Available-for-sale securities, net	—	—	1	—	1
Defined benefit plans, net	—	29	27	(29)	27
Other comprehensive income	5	33	35	(38)	35
Comprehensive Income/(Loss)	268	(363)	(730)	15	(810)
Less: Comprehensive (loss)/income attributable to noncontrolling interest and redeemable noncontrolling interest	—	(47)	25	(34)	(56)
Comprehensive Income/(Loss) Attributable to NRG Energy, Inc.	$ 268	$ (316)	$ (755)	$ 49	$ (754)

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEETS

December 31, 2017

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated
ASSETS			(In millions)		
Current Assets					
Cash and cash equivalents	$ —	$ 348	$ 643	$ —	$ 991
Funds deposited by counterparties	37	—	—	—	37
Restricted cash	4	504	—	—	508
Accounts receivable, net	912	163	4	—	1,079
Inventory	338	194	—	—	532
Derivative instruments	646	29	9	(58)	626
Cash collateral paid in support of energy risk management activities	170	1	—	—	171
Accounts receivable - affiliate	685	133	(129)	(594)	95
Current assets held-for-sale	8	107	—	—	115
Prepayments and other current assets	122	112	27	—	261
Total current assets	2,922	1,591	554	(652)	4,415
Property, plant and equipment, net	2,507	11,188	238	(25)	13,908
Other Assets					
Investment in subsidiaries	266	—	7,581	(7,847)	—
Equity investments in affiliates	—	1,036	2	—	1,038
Note receivable, less current portion	—	2	38	(38)	2
Goodwill	360	179	—	—	539
Intangible assets, net	454	1,295	—	(3)	1,746
Nuclear decommissioning trust fund	692	—	—	—	692
Derivative instruments	126	15	31	—	172
Deferred income taxes	377	(7)	(236)	—	134
Non-current assets held for sale	—	43	—	—	43
Other non-current assets	50	459	120	—	629
Total other assets	2,325	3,022	7,536	(7,888)	4,995
Total Assets	$ 7,754	$ 15,801	$ 8,328	$ (8,565)	$ 23,318
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ —	$ 667	$ 59	$ (38)	$ 688
Accounts payable	610	216	55	—	881
Accounts payable — affiliate	742	(297)	181	(593)	33
Derivative instruments	556	57	—	(58)	555
Cash collateral received in support of energy risk management activities	37	—	—	—	37
Current liabilities held-for-sale	—	72	—	—	72
Accrued expenses and other current liabilities	303	162	425	—	890
Accrued expenses and other current liabilities - affiliate	—	—	161	—	161
Total current liabilities	2,248	877	881	(689)	3,317
Other Liabilities					
Long-term debt and capital leases	244	8,733	6,739	—	15,716
Nuclear decommissioning reserve	269	—	—	—	269
Nuclear decommissioning trust liability	415	—	—	—	415
Deferred income taxes	112	64	(155)	—	21
Derivative instruments	136	61	—	—	197
Out-of-market contracts, net	66	141	—	—	207
Non-current liabilities held-for-sale	—	8	—	—	8
Other non-current liabilities	410	321	391	—	1,122
Total non-current liabilities	1,652	9,328	6,975	—	17,955
Total Liabilities	3,900	10,205	7,856	(689)	21,272
Redeemable noncontrolling interest in subsidiaries	—	78	—	—	78
Stockholders' Equity	3,854	5,518	472	(7,876)	1,968

Total Liabilities and Stockholders' Equity	$ 7,754	$ 15,801	$ 8,328	$ (8,565)	$ 23,318

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the six months ended June 30, 2017
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated
			(In millions)		
Cash Flows from Operating Activities					
Net income/(loss)	$ 263	$ (396)	$ (765)	$ 53	$ (845)
Loss from discontinued operations	—	(160)	(615)	—	(775)
Net income/(loss) from continuing operations	263	(236)	(150)	53	(70)
Adjustments to reconcile net income/(loss) to net cash provided/(used) by operating activities:					
Distributions from unconsolidated affiliates	—	32	—	(4)	28
Equity in (earnings)/losses of unconsolidated affiliates	—	(4)	2	—	(2)
Depreciation, amortization and accretion	198	303	16	—	517
Provision for bad debts	17	1	—	—	18
Amortization of nuclear fuel	24	—	—	—	24
Amortization of financing costs and debt discount/premiums	—	20	9	—	29
Amortization of intangibles and out-of-market contracts	12	39	—	—	51
Amortization of unearned equity compensation	—	—	16	—	16
Impairment losses	42	21	—	—	63
Changes in deferred income taxes and liability for uncertain tax benefits	131	237	(360)	—	8
Changes in nuclear decommissioning trust liability	2	—	—	—	2
Changes in derivative instruments	12	(12)	7	—	7
Changes in collateral deposits in support of energy risk management activities	(203)	11	3	—	(189)
Proceeds from sale of emission allowances	11	—	—	—	11
Gain on sale of assets	(22)	—	—	—	(22)
Changes in other working capital	(329)	(539)	538	(49)	(379)
Net cash provided/(used) by continuing operations	158	(127)	81	—	112
Cash used by discontinued operations	—	(38)	—	—	(38)
Net Cash Provided/(Used) by Operating Activities	158	(165)	81	—	74
Cash Flows from Investing Activities					
Dividends from NRG Yield, Inc.	—	—	45	(45)	—
Intercompany dividends	—	—	129	(129)	—
Acquisition of Drop Down Assets, net of cash acquired	—	(131)	—	131	—
Acquisition of businesses, net of cash acquired	—	(16)	—	—	(16)
Capital expenditures	(90)	(436)	(16)	—	(542)
Decrease in notes receivable	8	—	—	—	8
Purchases of emission allowances	(30)	—	—	—	(30)
Proceeds from sale of emission allowances	59	—	—	—	59
Investments in nuclear decommissioning trust fund securities	(279)	—	—	—	(279)
Proceeds from the sale of nuclear decommissioning trust fund securities	277	—	—	—	277
Proceeds from renewable energy grants and state rebates	—	8	—	—	8
Proceeds from sale of assets, net of cash disposed of	35	—	—	—	35
Change in investments in unconsolidated affiliates	—	(30)	—	—	(30)
Other	18	—	—	—	18
Net cash (used)/provided by continuing operations	(2)	(605)	158	(43)	(492)
Cash used by discontinued operations	—	(53)	—	—	(53)
Net Cash (Used)/Provided by Investing Activities	(2)	(658)	158	(43)	(545)
Cash Flows from Financing Activities					
Dividends from NRG Yield, Inc.	—	(45)	—	45	—
Payments (for)/from intercompany loans	—	(129)	—	129	—
Acquisition of Drop Down Assets, net of cash acquired	—	—	131	(131)	—
Intercompany dividends	(122)	369	(247)	—	—
Payment of dividends to common and preferred stockholders	—	—	(19)	—	(19)
Net receipts from settlement of acquired derivatives that include financing elements	—	2	—	—	2
Proceeds from issuance of long-term debt	—	741	205	—	946
Payments for short and long-term debt	—	(316)	(214)	—	(530)

Increase in notes receivable from affiliate	—	(125)	—	—	(125)
Distributions to, net of contributions from, noncontrolling interests in subsidiaries	—	14	—	—	14
Payments of debt issuance costs	—	(32)	(4)	—	(36)
Other - contingent consideration	—	(10)	—	—	(10)
Net cash (used)/provided by continuing operations	(122)	469	(148)	43	242
Cash used by discontinued operations	—	(224)	—	—	(224)
Net Cash (Used)/Provided by Financing Activities	(122)	245	(148)	43	18
Effect of exchange rate changes on cash and cash equivalents	—	(8)	—	—	(8)
Change in cash from discontinued operations	—	(315)	—	—	(315)
Net Increase/(Decrease) in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash	34	(271)	91	—	(146)
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period	13	1,050	323	—	1,386
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period	$ 47	$ 779	$ 414	$ —	$ 1,240

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

ITEM 2 — MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

As you read this discussion and analysis, refer to NRG's Condensed Consolidated Statements of Operations to this Form 10-Q, which present the results of operations for the three and six months ended June 30, 2018 and 2017. Also refer to NRG's 2017 Form 10-K, which includes detailed discussions of various items impacting the Company's business, results of operations and financial condition, including: Introduction and Overview section; NRG's Business Strategy section; Business section, including how regulation, weather, and other factors affect NRG's business; and Critical Accounting Policies and Estimates section.

The discussion and analysis below has been organized as follows:

- Executive summary, including introduction and overview, business strategy, and changes to the business environment during the period, including environmental and regulatory matters;
- Results of operations;
- Financial condition, addressing liquidity position, sources and uses of liquidity, capital resources and requirements, commitments, and off-balance sheet arrangements; and
- Known trends that may affect NRG's results of operations and financial condition in the future.

Executive Summary

Introduction and Overview

NRG Energy, Inc., or NRG or the Company, is a customer-driven integrated power company built on a portfolio of leading retail electricity brands and diverse generation assets. NRG is continuously focused on serving the energy needs of end-use residential, commercial and industrial customers in competitive markets through multiple brands and channels. The Company:

- directly sells energy and innovative, sustainable products and services to retail customers under the names "NRG", "Reliant" and other retail brand names owned by NRG;
- owns and operates approximately 30,000 MW of generation;
- engages in the trading of wholesale energy, capacity and related products; and
- transacts in and trades fuel and transportation services.

NRG was incorporated as a Delaware corporation on May 29, 1992.

The following table summarizes NRG's global generation portfolio as of June 30, 2018, by operating segment:

	Global Generation Portfolio[(a)] (In MW)					
	Generation					
Generation Type	Gulf Coast[(f)(i)]	East/West[(b)]	Renewables[(c)(g)(j)(k)]	NRG Yield[(d)(j)]	Other[(e)(j)]	Total Global
Natural gas[(f)]	7,464	4,878	—	1,888	—	14,230
Coal	5,114	3,871	—	—	—	8,985
Oil	—	3,641	—	190	—	3,831
Nuclear	1,136	—	—	—	—	1,136
Wind[(g)]	—	—	739	2,200	—	2,939
Utility Scale Solar	—	—	342	921	—	1,263
Distributed Solar	—	—	189	52	114	355
Total generation capacity[(h)]	13,714	12,390	1,270	5,251	114	32,739
Capacity attributable to noncontrolling interest[(h)]	—	—	(580)	(2,358)	—	(2,938)
Total net generation capacity	13,714	12,390	690	2,893	114	29,801

(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) Includes International and BETM.

(c) Includes Distributed Solar capacity from assets held by DGPV Holdco 1, DGPV Holdco 2, and DGPV Holdco 3.

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

(e) The Distributed Solar figure within "Other" includes the aggregate production capacity of installed and activated residential solar energy systems. Also includes capacity from operating portfolios of residential solar assets held by RPV Holdco.

(f) Natural gas generation does not include 371 MW related to Greens Bayou 5 which was retired in January 2018.

(g) During the first quarter of 2018, NRG sold 10 MW to third parties related to the Minnesota wind assets.

(h) NRG Yield's total generation capacity includes 6 MW for noncontrolling interest for Spring Canyon II and III. NRG Yield's total generation capacity net of this noncontrolling interest was 5,247 MW.

(i) Includes the South Central business, which owns and operates a 3,555 MW portfolio of generation assets in Gulf Coast, and which the Company expects to sell as announced on February 6, 2018. NRG will lease back the 1,263 MW Cottonwood facility.

(j) Includes net MW for NRG Yield, Inc. of 2,893 MW and the Renewables operating and development platform of 467 MW, which the Company expects to sell as announced on February 6, 2018.

(k) Does not include net MW for Ivanpah of 196 MW due to deconsolidation in the second quarter of 2018.

Strategy

NRG's strategy is to maximize stockholder value through the safe production and sale of reliable power to its customers in the markets served by the Company, while positioning the Company to provide fully integrated solutions to the end-use energy consumer. This strategy is intended to enable the Company to create and maintain growth at reasonable margins while de-risking the Company in terms of reduced and mitigated exposure to cyclical commodity price risk. At the same time, the Company's relentless commitment to safety for its employees, customers and partners continues unabated.

To effectuate the Company’s strategy, NRG is focused on: (i) excellence in operating performance of its existing assets including repowering its power generation assets at premium sites and optimal hedging of generation assets and retail load operations; (ii) serving the energy needs of end-use residential, commercial and industrial customers in competitive markets through multiple brands and channels with a variety of retail energy products and services differentiated by innovative features, premium service, sustainability, and loyalty/affinity programs; (iii) deploying innovative and renewable energy solutions for consumers within its retail businesses; and (iv) engaging in a proactive capital allocation plan focused on achieving the regular return of and on stockholder capital within the dictates of prudent balance sheet management, including reducing consolidated debt and pursuing selective acquisitions, joint ventures, divestitures and investments.

Transformation Plan

NRG is in the process of executing its Transformation Plan, which is designed to significantly strengthen earnings and cost competitiveness, lower risk and volatility, and create significant shareholder value. The Company expects to fully implement the Transformation Plan by the end of 2020 with significant completion by the end of 2018. The three-part, three-year plan is comprised of the following targets, and the Company's achievements towards such targets are as follows:

Operations and cost excellence — Cost savings and margin enhancement of $1,065 million recurring, 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.

Portfolio optimization — Targeting up to $3.2 billion of asset sale cash proceeds, including divestitures of 6 GW of conventional generation and businesses (excluding GenOn) and the expected monetization of 100% of its interest in NRG Yield, Inc. and its renewables platform.

- In 2017, NRG executed asset sales of 322 MW for aggregate cash of $150 million, which includes sales to NRG Yield, Inc. and the sale of Minnesota wind projects to third parties.
- On February 6, 2018, NRG announced agreements to sell (i) NRG's full ownership interest in NRG Yield, Inc. and NRG's renewables platform, a 3,440 MW portfolio, for cash of $1.375 billion, subject to certain adjustments; and (ii) NRG's South Central business, a 3,555 MW portfolio of generation assets, for cash of $1.0 billion, subject to certain adjustments. The transactions are subject to certain closing conditions and are expected to close in the second half of 2018.
- On February 6, 2018, the Company entered into an agreement with NRG Yield, Inc. to sell 100% of the membership interests in Carlsbad Energy Holdings LLC, which owns the Carlsbad project, a 527-MW natural gas-fired project in Carlsbad, CA, pursuant to the ROFO Agreement. The purchase price for the transaction is $365 million in cash consideration, subject to customary working capital and other adjustments.
- On March 30, 2018, the Company completed the sale of 100% of its ownership interest in Buckthorn Solar to NRG Yield, Inc. for cash consideration of approximately $42 million.
- During the first half of 2018, the Company completed the sale of various other assets for approximately $7 million.
- On June 19, 2018, the Company completed the sale of the substantially completed assets of the UPMC Thermal Project to NRG Yield, Inc. for cash consideration of $84 million, subject to working capital adjustments.
- On August 1, 2018, the Company completed the sale of 100% of its ownership interests in BETM to a third party for $70 million, subject to working capital adjustments. The sale also resulted in the release and return of approximately $119 million of letters of credit, $30 million of parent guarantees, and $4 million of net cash collateral to NRG.

Capital structure and allocation enhancements — A prioritized capital allocation strategy that targets a reduction in consolidated debt to achieve its targeted 3.0x net debt / Adjusted EBITDA credit ratio.

- Expected reduction in non-recourse debt related to the sale of NRG's ownership in NRG Yield, Inc. and the NRG renewables platform and the sales of Carlsbad Energy Center and Buckthorn Solar.
- Year to date open market repurchases of $93 million, representing principal reduction of Senior Notes of $89 million.

Working Capital and Costs to Achieve — The Company expects to realize (i) $370 million of non-recurring working capital improvements through 2020 and (ii) approximately $290 million, one-time costs to achieve.

- Since the inception of the Transformation Plan, NRG has realized $298 million of non-recurring working capital improvements and $113 million of one-time costs to achieve.

Regulatory Matters

The Company’s regulatory matters are described in the Company’s 2017 Form 10-K in Item 1, Business — *Regulatory Matters.* These matters have been updated below and in Note 16, *Regulatory Matters,* to the Condensed Consolidated Financial Statements of this Form 10-Q as found in Item 1.

As owners of power plants and participants in wholesale and retail energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include the CFTC, FERC, NRC, and the PUCT, as well as other public utility commissions in certain states where NRG's generating, thermal, or distributed generation assets are located. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO and RTO markets in which it participates. Likewise, certain NRG entities participating in the retail markets are subject to rules and regulations established by the states in which NRG entities are licensed to sell at retail. NRG must also comply with the mandatory reliability requirements imposed by 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

Department of Energy's Proposed Grid Resiliency Pricing Rule and Subsequent FERC Proceeding — On September 29, 2017, the Department of Energy issued a proposed rulemaking titled the "Grid Resiliency Pricing Rule." The rulemaking directs FERC to take action to reform the ISO/RTO markets to value certain reliability and resiliency attributes of electric generation resources. On October 2, 2017, FERC issued a notice inviting comments. On October 4, 2017, FERC staff issued a series of questions requesting commenters to address. On October 23, 2017, NRG filed comments encouraging FERC to act expeditiously to modernize energy and capacity markets in a manner compatible with robust competitive markets. On January 8, 2018, FERC terminated the proposed rulemaking and opened a new proceeding asking each ISO/RTO to address specific questions focused on grid resilience. On March 9, 2018, the ISOs/RTOs filed comments to the questions posed by FERC. The Company responded on May 9, 2018 and is currently awaiting a decision from FERC.

State Energy Regulation

State Out-Of-Market Subsidy Proposals — On April 12, 2018, the New Jersey State Legislature passed a bill to provide out-of-market subsidies to the state’s nuclear plants. The bill has not yet been signed by the New Jersey Governor. In addition, Certain other states in the areas of the country in which NRG operates, including Ohio and Pennsylvania, have considered but have not enacted proposals to provide out-of-market subsidy payments to potentially uneconomic nuclear and fossil generating units. NRG has opposed efforts to provide out-of-market subsidies, and intends to continue opposing them in the future.

Regional Regulatory Developments

NRG is affected by rule/tariff changes that occur in the ISO regions. For further discussion on regulatory developments see Note 16, *Regulatory Matters*, to the Consolidated Financial Statements.

Gulf Coast

MISO

Revisions to MISO Capacity Construct — On February 28, 2018, FERC issued two orders on MISO’s capacity market design, which together, re-affirm MISO’s existing capacity market structure. FERC also held that, even though there was a period of time between where MISO’s capacity market structure may not have just and reasonable, FERC exercised its remedial authority not to rerun past auctions. On March 30, 2018, the Company filed a motion for rehearing with FERC. The eventual outcome of this proceeding will affect capacity prices in MISO and the incentive for generators in MISO to sell capacity into neighboring markets.

East/West

PJM

2021/2022 PJM Auction Results — On May 23, 2018, PJM announced the results of its 2021/2022 base residual auction. NRG, excluding GenOn, cleared approximately 4,740 MW of Capacity Performance product. NRG's expected capacity revenues, excluding GenOn, from the base residual auction for the 2021/2022 delivery year are approximately $328 million.

The table below provides a detailed description of NRG's 2021/2022 base residual auction results from May 23, 2018:

	Capacity Performance Product	
Zone	**Cleared Capacity (MW)[(a)]**	**Price ($/MW-day)**
COMED	3,995	$ 195.55
DPL	552	$ 165.73
MAAC	121	$ 140.00
PEPCO	72	$ 140.00
Total	4,740	

(a) Does not include capacity sold by NRG Curtailment Specialists.

Capacity Market Reforms Filing — On April 9, 2018, PJM filed with FERC two capacity market reform proposals in one filing attempting to address market impacts created by out-of-market subsidies. PJM proposed a capacity re-pricing proposal as its preferred option to accommodate state subsidies in the wholesale market. In the alternative, PJM proposes extending its MOPR to existing resources, along with other changes. On June 29, 2018, FERC issued an order rejecting both of the PJM proposals. Instead, FERC found the existing PJM tariff unjust and unreasonable, and initiated a new proceeding to develop a just and reasonable outcome. Among other things, FERC directed PJM to adopt a minimum price rule that would apply to all subsidized resources, including nuclear and renewable resources. Additionally, FERC directed PJM to consider whether to allow state regulators to remove equal amounts of subsidized generation and load from the capacity market. FERC established a briefing schedule and committed to issuing a final order in early 2019 for implementation for next year's BRA.

PJM Seasonal Capacity Proceeding — On November 17, 2016, PJM proposed to allow winter- and summer-peaking capacity resources to "aggregate" their seasonal capacity into an annual capacity product eligible to participate as Capacity Performance resources. NRG filed comments specifically supporting PJM's proposal to modify the aggregation rules to allow seasonal capacity resources to aggregate across LDAs and to allow aggregations through RPM auctions, but opposing the move to seasonal capacity. On January 23, 2017, PJM amended its proposal to address questions from FERC. On March 21, 2017, FERC issued a decision accepting PJM's seasonal capacity aggregation filing pursuant to FERC staff's delegated authority, since FERC did not have a quorum at the time. On February 23, 2018, FERC re-affirmed its prior order. On February 23, 2018, FERC accepted PJM's filing and dismissed the requests for clarification. The outcome of this proceeding could have a material impact on future PJM capacity prices.

Complaints Related to Extension of Base Capacity — In 2015, FERC approved changes to PJM's capacity market, which included moving from the Base Capacity product to the higher performance Capacity Performance product over the course of a five year transition. Under this transition, as of the May 2017 BRA, the Base Capacity product will no longer be available. Several parties have filed complaints at FERC seeking to maintain the RPM Base Capacity product for at least one more delivery year or until such time as PJM develops a model for seasonal resources to participate. On February 23, 2018, FERC issued an Order scheduling a technical conference and established a refund effective date of December 23, 2016 and January 5, 2017 for the complaints. Multiple parties filed for rehearing. FERC held a technical conference on April 24, 2018 and received post-technical conference comments on July 13, 2018. The outcome of this proceeding could have a material impact on future PJM capacity prices.

New England

ISO-NE Retention of Mystic Units — ISO-NE recently announced that it had denied delist bids submitted by two of the three Mystic generating units attached to the DistriGas LNG terminal outside of Boston, citing local reliability concerns. Subsequently, ISO-NE announced its intent to retain the Mystic units in future auctions through an out-of-market payment, citing "fuel security" concerns. On May 1, 2018, ISO-NE filed with FERC to allow it to retain the Mystic units. On July 2, 2018, FERC issued an order denying ISO-NE's request for a waiver and initiated a new proceeding to examine whether ISO-NE's capacity market rules were just and reasonable. Among other things, FERC found that ISO-NE should file a short-term fuel security agreement as part of its tariff and then redesign its capacity market to allow units retained for fuel security to set price in the capacity market. Additional briefing is due 90 days after issuance of the order.

Competitive Auctions with Sponsored Resources Proposal (CASPR) — On January 8, 2018, ISO-NE filed the CASPR proposal which attempts to accommodate state sponsored resources while maintaining competitive market pricing. On January 29, 2018, NRG protested certain aspects of the proposal and also supported ISO-NE’s beginning attempts to address state sponsored resources entering the capacity market. On March 9, 2018, FERC accepted ISO-NE's proposal. On April 9, 2018, NRG joined another generator in filing a request for rehearing. The rehearing is pending at FERC. The outcome of this proceeding will potentially affect future capacity market prices.

Renewable Technology Resource (RTR) Exemption — In 2014, FERC approved a package of revisions that included a renewables exemption called the RTR Exemption. After FERC denied rehearing, the case was appealed to the D.C. Circuit. After a voluntary remand motion, the Court remanded the case back to FERC. In 2016, FERC issued an order reaffirming its decision. In 2017, a group of generators, including NRG, filed a petition for review with the D.C. Circuit. On July 31, 2018, the Court upheld FERC's decision.

Northern Pass Siting Application — On February 1, 2018, the New Hampshire Site Evaluation Committee denied the application for Northern Pass Transmission to cross the state with a 160-mile transmission line from Quebec into southern New Hampshire. The Northern Pass transmission line project had previously been awarded a contract by the State of Massachusetts, which is now in doubt. The addition of 1,000 MW of additional Canadian hydropower associated with Northern Pass would have affected energy and capacity prices. On February 28, 2018, Northern Pass Transmission filed a motion for rehearing. On March 13, 2018, the New Hampshire Site Evaluation Committee suspended the request for rehearing pending a written decision on the project's full application.

New York

Independent Power Producers of New York (IPPNY) Complaint — On January 9, 2017, EPSA requested FERC to promptly direct the NYISO to file tariff provisions to address pending market concerns related to out-of-market payments to existing generation in the NYISO. This request was prompted by the ZEC program initiated by the NYSPSC. This request follows IPPNY’s complaint at FERC against the NYISO on May 10, 2013, as amended on March 25, 2014. On April 5, 2018, EPSA filed a motion for renewed request for expedited action on the MOPR. The generators asked FERC to direct the NYISO to require that capacity from existing generation resources that would have exited the market but for out-of-market payments be mitigated. Failure to implement buyer-side mitigation measures could result in uneconomic entry, which artificially decreases capacity prices below competitive market levels.

New York Public Service Commission Retail Energy Market Proceedings — On February 23, 2016, the NYSPSC issued what it refers to as its “Retail Reset” order, or Reset Order, in Docket 12-M-0476 et al. Among other things, the Reset Order placed a price cap on energy supply offers and required many retail providers to seek affirmative consent from certain retail customers. Various parties have challenged the NYPSC’s authority to regulate prices charged by competitive suppliers in New York state court. On March 29, 2018, the New York State Court of Appeals granted a motion by the Retail Energy Supply Association and National Energy Marketers Association for leave to appeal an earlier adverse Appellate Division ruling. In conjunction with the court challenges, the NYPSC noticed both an evidentiary and a collaborative track to address the functioning of the competitive retail markets. An administrative hearing on the evidentiary track concluded on December 12, 2017 after 10 days of testimony and is now in the post-hearing brief phase. The outcome of the evidentiary and collaborative processes, combined with the outcome of the appeal of the Reset Order, could affect the viability of the New York retail energy market.

CAISO

Puente Power Project — On October 5, 2017, the California Energy Commission, or CEC, the agency responsible for permitting the Puente Power Project, issued a statement on behalf of the committee of two Commissioners overseeing the permitting process stating their intention to issue a proposed decision that would deny a permit for the Puente Power Project. On October 16, 2017, NRG filed a motion to suspend the permitting proceeding for at least six months, which was granted on November 3, 2017. On May 31, 2018, the CEC extended the suspension period at NRG's request to July 1, 2019. The supplemental extension period should allow sufficient time to determine whether alternate procurement efforts undertaken by SCE supersede the need for the Puente Power Project.

Environmental Matters

NRG is subject to numerous environmental laws in the development, construction, ownership and operation of projects. These laws generally require that governmental permits and approvals be obtained before construction and during operation of power plants. Federal and state environmental laws historically have become more stringent over time. Future laws may require the addition of emissions controls or other environmental controls or impose restrictions on our operations, which could affect the Company's operations. Complying with environmental laws often involves significant capital and operating expenses, as well as occasionally curtailing operations. NRG decides to invest capital for environmental controls based on the relative certainty of the requirements, an evaluation of compliance options, and the expected economic returns on capital.

A number of regulations that may affect the Company are under review by the EPA, including ESPS for GHGs, ash disposal requirements, NAAQS revisions and implementation and effluent limitation guidelines. NRG will evaluate the impact of these regulations as they are revised but cannot fully predict the impact of each until anticipated legal challenges are resolved. The Company's environmental matters are described in the Company's 2017 Form 10-K in Item 1, Business - *Environmental Matters* and Item 1A, Risk Factors. These matters have been updated in Item 1 — Note 17, *Environmental Matters,* to the Condensed Consolidated Financial Statements of this Form 10-Q and as follows.

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.

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. The EPA has stated that it intends to further revise the rule.

Water

Clean Water Act — The Company is required under the CWA to comply with intake and discharge requirements, requirements for technological controls and operating practices. As with air quality regulations, federal and state water regulations have become more stringent and imposed new requirements.

Once Through Cooling Regulation — In August 2014, EPA finalized the regulation regarding the use of water for once through cooling at existing facilities to address impingement and entrainment concerns. NRG anticipates that more stringent requirements will be incorporated into some of its water discharge permits over the next several years as NPDES permits are renewed.

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

Regional Environmental Developments

Texas Regional Haze — On October 17, 2017, the EPA promulgated a final rule creating a Texas-only SO_2 cap-and-trade program to address regional haze. The program is scheduled to begin on January 1, 2019. Several of the Company's units in Texas will be affected by this rule. The rule has been challenged by several environmental groups in the Fifth Circuit of the U.S. Court of Appeals, which litigation has been stayed pending resolution of administrative petitions for reconsideration.

Significant Events

The following significant events have occurred during 2018, as further described within this Management's Discussion and Analysis and the Condensed Consolidated Financial Statements:

NRG Transformation Plan

- As described above, the Company has continued to execute on its Transformation Plan.

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 $219 million in cash, inclusive of approximately $54 million in payments for estimated working capital, which is subject to further adjustment. The acquisition increased NRG's retail portfolio by approximately 300,000 customers in the aggregate by June 30, 2018.

Ivanpah Deconsolidation

- During the second quarter of 2018, the Company, recognized a loss of $22 million on the deconsolidation and subsequent recognition of its 54.6% interest in Ivanpah as an equity method investment, as discussed in more detail in Note 9, *Variable Interest Entities, or VIEs*.

Financing Activities

- On March 21, 2018, the Company repriced the 2023 Term Loan Facility, reducing the interest rate margin by 50 basis points to LIBOR plus 1.75% and reducing the LIBOR floor to 0.00%. As a result of the repricing, the Company expects approximately $47 million in interest savings over the remaining life of the loan.

- On May 24, 2018, the Company issued $575 million in aggregate principal amount at par of 2.75% convertible senior notes due 2048, as discussed in more detail in Note 8, *Debt and Capital Leases.*

- On June 19, 2018, the Company entered into an amended and restated Thermal note purchase and private shelf agreement whereas it authorized the issuance of the Series E Notes, Series F Notes, Series G Notes, and Series H Notes, as discussed in more detail in Note 8, *Debt and Capital Leases.*

- During the six months ended June 30, 2018, the Company repurchased $43 million in aggregate principal of its Senior Notes in the open market for $45 million, including accrued interest as discussed in more detail in Note 8, *Debt and Capital Leases.* In July 2018, the Company repurchased an additional $46 million in aggregate principal of its Senior Notes in the open market for $48 million including accrued interest.

- On August 1, 2018, the Company announced that it gave the required notice under the indenture governing its 6.25% Senior Notes due 2022, or the 2022 Notes, to redeem for cash $486 million aggregate principal amount of its 2022 Notes, or the Partial Redemption, on August 31, 2018, or the Redemption Date. The redemption price for the 2022 Notes will be 103.125% of the principal amount of the 2022 Notes, plus accrued and unpaid interest to the Redemption Date. The Partial Redemption, combined with recently completed open market repurchases of approximately $89 million of the Company's outstanding indebtedness, will result in the retirement of outstanding indebtedness equal to approximately $575 million which is the aggregate principal amount of the Company's 2.75% convertible senior notes due 2048 issued on May 24, 2018.

Share Repurchases

- In February 2018, the Company's board of directors authorized the Company to repurchase $1 billion of its common stock, with the first $500 million program beginning as soon as permitted. In March 2018, the Company repurchased 3,114,748 shares of NRG common stock for approximately $93 million. During the second quarter of 2018, the Company repurchased 11,748,553 shares of NRG common stock for approximately $407 million, including shares repurchased under the ASR Agreement. In July 2018, the Company received an additional 860,880 shares in connection with the settlement of the ASR Agreement, completing the $500 million of share repurchases. The average cost per share for the total $500 million of shares repurchased was $31.80.

Trends Affecting Results of Operations and Future Business Performance

The Company's trends are described in the Company's 2017 Form 10-K in Item 7, M*anagement's Discussion and Analysis of Financial Condition and Results of Operations - Trends Affecting Results of Operations and Future Business Performance,* and below.

ERCOT Pricing — ERCOT forward prices for July and August 2018 are significantly higher than where previous summers have settled. These elevated pricing levels mean that deviations from expected demand and/or generation availability may have a material impact on the Company's actual results.

Changes in Accounting Standards

See Note 2, *Summary of Significant Accounting Policies*, to the Condensed Consolidated Financial Statements of this Form 10-Q, for a discussion of recent accounting developments.

Consolidated Results of Operations

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Three months ended June 30, 2018	Three months ended June 30, 2017	Change	Six months ended June 30, 2018	Six months ended June 30, 2017	Change
Operating Revenues						
Energy revenue [a]	$ 673	$ 656	$ 17	$ 1,292	$ 1,243	$ 49
Capacity revenue [a]	313	297	16	601	559	42
Retail revenue	1,816	1,605	211	3,302	2,946	356
Mark-to-market for economic hedging activities	15	41	(26)	(91)	159	(250)
Contract amortization	(14)	(14)	—	(28)	(29)	1
Other revenues [b]	119	116	3	267	205	62
Total operating revenues	2,922	2,701	221	5,343	5,083	260
Operating Costs and Expenses						
Cost of sales [c]	1,515	1,422	(93)	2,908	2,683	(225)
Mark-to-market for economic hedging activities	86	(18)	(104)	(216)	118	334
Contract and emissions credit amortization [c]	7	8	1	13	16	3
Operations and maintenance	360	340	(20)	730	712	(18)
Other cost of operations	83	89	6	174	175	1
Total cost of operations	2,051	1,841	(210)	3,609	3,704	(95)
Depreciation and amortization	227	260	33	462	517	55
Impairment losses	74	63	(11)	74	63	(11)
Selling, general and administrative	211	221	10	402	481	79
Reorganization costs	23	—	(23)	43	—	(43)
Development costs	16	18	2	29	35	6
Total operating costs and expenses	2,602	2,403	(199)	4,619	4,800	181
Other income - affiliate	—	39	(39)	—	87	(87)
Gain on sale of assets	14	2	12	16	4	12
Operating Income	334	339	(5)	740	374	366
Other Income/(Expense)						
Equity in earnings/(losses) of unconsolidated affiliates	18	(3)	21	16	2	14
Other (losses)/income, net	(20)	14	(34)	(23)	26	(49)
Loss on debt extinguishment, net	(1)	—	(1)	(3)	(2)	(1)
Interest expense	(202)	(247)	45	(369)	(471)	102
Total other expense	(205)	(236)	31	(379)	(445)	66
Income/(Loss) from Continuing Operations before Income Taxes	129	103	26	361	(71)	432
Income tax expense/(benefit)	8	4	4	7	(1)	8
Income/(Loss) from Continuing Operations	121	99	22	354	(70)	424
Loss from discontinued operations, net of income tax	(25)	(741)	716	(25)	(775)	750
Net Income/(Loss)	96	(642)	738	329	(845)	1,174
Less: Net income/(loss) attributable to noncontrolling interest and redeemable noncontrolling interest	24	(16)	40	(22)	(55)	33
Net Income/(Loss) Attributable to NRG Energy, Inc.	$ 72	$ (626)	$ 698	$ 351	$ (790)	$ 1,141
Business Metrics						
Average natural gas price — Henry Hub ($/MMBtu)	$ 2.80	$ 3.18	(12)%	$ 2.90	$ 3.25	(11)%

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

Management's discussion of the results of operations for the three months ended June 30, 2018 and 2017

Electricity Prices

The following table summarizes average on peak power prices for each of the major markets in which NRG operates for the three months ended June 30, 2018 and 2017. The average on-peak power prices for ERCOT - Houston and COMED (PJM) decreased primarily due to the change in congestion pattern for the three months ended June 30, 2018, as compared to the same period in 2017.

	Average on Peak Power Price ($/MWh)		
	Three months ended June 30,		
Region	2018	2017	Change %
Gulf Coast [(a)]			
ERCOT - Houston [(b)]	$ 34.82	$ 46.03	(24)%
ERCOT - North[(b)]	34.89	27.80	26 %
MISO - Louisiana Hub[(c)]	44.20	42.77	3 %
East/West			
NY J/NYC[(c)]	36.41	39.35	(7)%
NEPOOL[(c)]	36.28	33.57	8 %
COMED (PJM)[(c)]	31.88	33.40	(5)%
PJM West Hub[(c)]	39.73	32.79	21 %
CAISO - NP15[(c)]	27.37	28.29	(3)%
CAISO - SP15[(c)]	27.75	30.72	(10)%

(a) Gulf Coast region also transacts in PJM - West Hub.
(b) Average on peak power prices based on real time settlement prices as published by the respective ISOs.
(c) Average on peak power prices based on day ahead settlement prices as published by the respective ISOs.

The following table summarizes average realized power prices for each region in which NRG operates for the three months ended June 30, 2018 and 2017, which reflects the impact of settled hedges.

	Average Realized Power Price ($/MWh)		
	Three months ended June 30,		
Region	2018	2017	Change %
Gulf Coast	$ 36.33	$ 34.68	5 %
East/West [(a)]	35.63	36.67	(3)%

(a) does not include BETM energy revenue of $15 million and $14 million for 2018 and 2017, respectively.

Though the average on peak power prices have remained relatively flat, average realized prices by region for the Company have generally fluctuated at different rates year-over-year due to the Company's multi-year hedging program.

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, retail 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 below tables present the composition and reconciliation of gross margin and economic gross margin for the three months ended June 30, 2018 and 2017:

	Three months ended June 30, 2018							
		Generation						
(In millions)	Retail	Gulf Coast	East/West(a)	Subtotal	Renewables	NRG Yield	Corporate/Eliminations	Total
Energy revenue	$ —	$ 508	$ 144	$ 652	$ 79	$ 192	$ (250)	$ 673
Capacity revenue	—	68	160	228	—	87	(2)	313
Retail revenue	1,817	—	—	—	—	—	(1)	1,816
Mark-to-market for economic hedging activities	—	289	(15)	274	5	—	(264)	15
Contract amortization	—	4	—	4	—	(18)	—	(14)
Other revenue (b)	—	42	18	60	29	46	(16)	119
Operating revenue	1,817	911	307	1,218	113	307	(533)	2,922
Cost of fuel	(4)	(260)	(70)	(330)	—	(9)	(25)	(368)
Other cost of sales(c)	(1,315)	(81)	(21)	(102)	(2)	(8)	280	(1,147)
Mark-to-market for economic hedging activities	(346)	(4)	—	(4)	—	—	264	(86)
Contract and emission credit amortization	—	(7)	—	(7)	—	—	—	(7)
Gross margin	**$ 152**	**$ 559**	**$ 216**	**$ 775**	**$ 111**	**$ 290**	**$ (14)**	**$ 1,314**
Less: Mark-to-market for economic hedging activities, net	(346)	285	(15)	270	5	—	—	(71)
Less: Contract and emission credit amortization, net	—	(3)	—	(3)	—	(18)	—	(21)
Economic gross margin	**$ 498**	**$ 277**	**$ 231**	**$ 508**	**$ 106**	**$ 308**	**$ (14)**	**$ 1,406**
Business Metrics								
MWh sold (thousands)(d)(e)		13,982	3,616		1,211	2,308		
MWh generated (thousands) (f)		12,959	2,903		1,211	2,675		

(a) Includes International, BETM and Generation eliminations

(b) Renewables other revenue includes $13 million of intercompany revenue to NRG Yield.

(c) Includes purchased energy, capacity and emissions credits

(d) MWh sold excludes generation at facilities in East/West and NRG Yield that generate revenue under capacity agreements.

(e) Does not include thermal MWh of 9 thousand or MWt of 462 thousand for thermal sold by NRG Yield.

(f) Does not include thermal MWh of 28 thousand or MWt of 462 thousand for thermal generated by NRG Yield.

	Three months ended June 30, 2017							
		Generation						
(In millions)	Retail	Gulf Coast	East/West(a)	Subtotal	Renewables	NRG Yield	Corporate/Eliminations	Total
Energy revenue	$ —	$ 484	$ 184	$ 668	$ 105	$ 177	$ (294)	$ 656
Capacity revenue	—	68	144	212	—	85	—	297
Retail revenue	1,605	—	—	—	—	—	—	1,605
Mark-to-market for economic hedging activities	(2)	(90)	13	(77)	(3)	—	123	41
Contract amortization	—	3	—	3	—	(17)	—	(14)
Other revenue (b)	—	55	21	76	17	43	(20)	116
Operating revenue	1,603	520	362	882	119	288	(191)	2,701
Cost of fuel	(2)	(284)	(82)	(366)	(1)	(7)	5	(371)
Other cost of sales(c)	(1,211)	(79)	(52)	(131)	(2)	(7)	300	(1,051)
Mark-to-market for economic hedging activities	158	(15)	(2)	(17)	—	—	(123)	18
Contract and emission credit amortization	—	(7)	(1)	(8)	—	—		(8)
Gross margin	**$ 548**	**$ 135**	**$ 225**	**$ 360**	**$ 116**	**$ 274**	**$ (9)**	**$ 1,289**
Less: Mark-to-market for economic hedging activities, net	156	(105)	11	(94)	(3)	—	—	59
Less: Contract and emission credit amortization, net	—	(4)	(1)	(5)	—	(17)	—	(22)
Economic gross margin	**$ 392**	**$ 244**	**$ 215**	**$ 459**	**$ 119**	**$ 291**	**$ (9)**	**$ 1,252**
Business Metrics								
MWh sold (thousands)(d)(e)		13,958	4,598		1,059	2,112		
MWh generated (thousands) (f)		13,101	3,079		1,059	2,425		

(a) Includes International, BETM and Generation eliminations.

(b) Renewables other revenue includes $7 million of intercompany revenue to NRG Yield.

(c) Includes purchased energy, capacity and emissions credits

(d) MWh sold excludes generation at facilities in the East, West and NRG Yield that generate revenue under capacity agreements.

(e) Does not include thermal MWh of 9 thousand or MWt of 418 thousand for thermal sold by NRG Yield.

(f) Does not include thermal MWh of 20 thousand or MWt of 418 thousand for thermal generated by NRG Yield.

The table below represents the weather metrics for the three months ended June 30, 2018 and 2017:

	Three months ended June 30,	
Weather Metrics	Gulf Coast	East/West
2018		
CDDs (a)	1,067	265
HDDs (a)	108	425
2017		
CDDs	921	281
HDDs	41	380
10-year average		
CDDs	970	259
HDDs	67	429

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

Retail gross margin and economic gross margin

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

(In millions except otherwise noted)	Three months ended June 30, 2018	2017
Retail revenue	$ 1,689	$ 1,515
Supply management revenue	42	52
Capacity revenue	86	38
Customer mark-to-market	—	(2)
Operating revenue [(a)]	1,817	1,603
Cost of sales [(b)]	(1,319)	(1,213)
Mark-to-market for economic hedging activities	(346)	158
Gross Margin	**$ 152**	**$ 548**
Less: Mark-to-market for economic hedging activities, net	(346)	156
Economic Gross Margin	**$ 498**	**$ 392**
Business Metrics		
Mass electricity sales volume — GWh - Gulf Coast	9,802	9,234
Mass electricity sales volume — GWh - All other regions	1,592	1,357
C&I electricity sales volume — GWh - All regions	5,403	5,308
Natural gas sales volumes (MDth)	1,244	438
Average Retail Mass customer count (in thousands)	2,973	2,859
Ending Retail Mass customer count (in thousands) [(c)]	3,173	2,887

(a) Includes intercompany sales of $1 million and $1 million in 2018 and 2017, respectively, representing sales from Retail to the Gulf Coast region.
(b) Includes intercompany purchases of $251 million and $293 million in 2018 and 2017, respectively.
(c) The acquisition of XOOM Energy, LLC increased NRG's retail portfolio by approximately 300,000 customers in the aggregate by June 30, 2018.

Retail gross margin decreased $396 million and economic gross margin increased $106 million for the three months ended June 30, 2018, compared to the same period in 2017, due to:

	(In millions)
Higher gross margin due to higher revenue of $63 million or approximately $3.25 per MWh, driven by customer product, term and mix, offset by higher supply costs of $25 million or approximately $1.25 per MWh, driven by an increase in power prices	$ 38
Higher gross margin from the Business Solutions unit reflecting the early settlement of capacity obligations for 2018	34
Higher gross margin due to an increase in load of 790,000 MWh driven by warmer weather conditions in 2018 as compared to 2017	27
Higher gross margin due to higher volumes driven by higher average customer counts primarily driven by the XOOM acquisition in June 2018	7
Increase in economic gross margin	$ 106
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(502)
Decrease in gross margin	**$ (396)**

Generation gross margin and economic gross margin

Generation gross margin increased $415 million and economic gross margin increased $49 million, both of which include intercompany sales, during the three months ended June 30, 2018, compared to the same period in 2017.

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

Gulf Coast Region

		(In millions)
Higher gross margin due to a 5% increase in average realized prices in South Central and a 6% increase in average realized prices in Texas	$	45
Higher capacity margins due to an increase in load demand in the South Central business		10
Lower energy margin due to a 14% increase in supply cost on load contracts		(9)
Lower capacity revenue due to the cancellation of the Greens Bayou RMR agreement in 2017		(6)
Lower gross margin from commercial optimization activities		(5)
Other		(2)
Increase in economic gross margin	$	33
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		391
Increase in gross margin	**$**	**424**

East/West

		(In millions)
Higher gross margin due to a 80% increase in New England cleared capacity pricing	$	16
Higher gross margin due to a 26% increase in PJM cleared capacity pricing which relates to the first full period of capacity performance product pricing		15
Lower gross margin due to a 29% decrease in capacity pricing in New York of $15 million and decreases in capacity pricing and volumes due to the Long Beach capacity toll expiration in July 2017 of $4 million		(19)
Lower gross margin due to a 6% decrease in generation volumes due to timing of planned and unplanned outages at Midwest Generation, offset by favorable fuel costs		(8)
Higher gross margin due to insurance proceeds from outages of $14 million in 2018, compared to business interruption proceeds of $8 million in 2017		6
Other		6
Increase in economic gross margin	$	16
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		(26)
Increase in contract and emission credit amortization		1
Decrease in gross margin	**$**	**(9)**

Renewables gross margin and economic gross margin

Renewables gross margin decreased $5 million and economic gross margin decreased $13 million for the three months ended June 30, 2018, compared to the same period in 2017. This was driven by the deconsolidation of Ivanpah in May 2018, partially offset by additional distributed solar projects reaching commercial operations in late 2017 and early 2018.

NRG Yield gross margin and economic gross margin

NRG Yield gross margin increased $16 million and economic gross margin increased $17 million for the three months ended June 30, 2018, compared to the same period in 2017. The increase is due to a 9% increase in volume generated by wind projects, primarily the Alta Wind projects and Wildorado from increased wind resources, as well as a 2% increase in solar generation, primarily at CVSR due to higher insolation.

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 $130 million during the three months ended June 30, 2018, compared to the same period in 2017.

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

	Three months ended June 30, 2018					
		Generation				
	Retail	Gulf Coast	East/West	Renewables	Eliminations[(a)]	Total
	(In millions)					
Mark-to-market results in operating revenues						
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ —	$ (52)	$ (8)	$ —	$ 28	$ (32)
Net unrealized gains/(losses) on open positions related to economic hedges	—	341	(7)	5	(292)	47
Total mark-to-market gains/(losses) in operating revenues	$ —	$ 289	$ (15)	$ 5	$ (264)	$ 15
Mark-to-market results in operating costs and expenses						
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 62	$ (2)	$ (3)	$ —	$ (28)	$ 29
Reversal of acquired gain positions related to economic hedges	(1)	—	—	—	—	(1)
Net unrealized (losses)/gains on open positions related to economic hedges	(407)	(2)	3	—	292	(114)
Total mark-to-market (losses)/gains in operating costs and expenses	$ (346)	$ (4)	$ —	$ —	$ 264	$ (86)

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

	Three months ended June 30, 2017					
		Generation				
	Retail	Gulf Coast	East/West	Renewables	Eliminations[(a)]	Total
	(In millions)					
Mark-to-market results in operating revenues						
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (1)	$ (7)	$ (11)	$ —	$ 50	$ 31
Net unrealized (losses)/gains on open positions related to economic hedges	(1)	(83)	24	(3)	73	10
Total mark-to-market (losses)/gains in operating revenues	$ (2)	$ (90)	$ 13	$ (3)	$ 123	$ 41
Mark-to-market results in operating costs and expenses						
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 45	$ (4)	$ —	$ —	$ (50)	$ (9)
Reversal of acquired loss positions related to economic hedges	1	—	—	—	—	1
Net unrealized gains/(losses)on open positions related to economic hedges	112	(11)	(2)	—	(73)	26
Total mark-to-market gains/(losses) in operating costs and expenses	$ 158	$ (15)	$ (2)	$ —	$ (123)	$ 18

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

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

For the three months ended June 30, 2018, the $15 million gain in operating revenues from economic hedge positions was driven primarily by an increase in the value of open positions as a result of ERCOT heat rate contraction and decreases in ERCOT electricity prices, partially offset by the reversal of previously recognized unrealized gains on contracts that settled during the period. The $86 million loss in operating costs and expenses from economic hedge positions was driven primarily by a decrease in value of open positions as a result of ERCOT heat rate contraction and decreases in ERCOT electricity prices, partially offset by the reversal of previously recognized unrealized losses on contracts that settled during the period.

For the three months ended June 30, 2017, the $41 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 PJM power prices and New York capacity prices, partially offset by a decrease in value of open positions as a result of ERCOT heat rate expansion. The $18 million gain in operating costs and expenses from economic hedge positions was driven primarily by an increase in value of open positions as a result of ERCOT heat rate expansion, partially offset by a decrease in value of open positions as a result of decrease in coal prices and the reversal of previously recognized unrealized gains on contracts that settled during the period.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the three months ended June 30, 2018 and 2017. The realized and unrealized financial and physical trading results are included in operating revenue within the Generation segment. The Company's trading activities are subject to limits within the Company's Risk Management Policy and are primarily transacted through BETM.

	Three months ended June 30,	
(In millions)	**2018**	**2017**
Trading gains		
Realized	$ 25	$ 14
Unrealized	5	12
Total trading gains	$ 30	$ 26

Operations and Maintenance Expense

		Generation						
	Retail	**Gulf Coast**	**East/West[a]**	**Renewables**	**NRG Yield**	**Corporate**	**Eliminations**	**Total**
					(In millions)			
Three months ended June 30, 2018	$ 49	$ 156	$ 99	$ 25	$ 42	$ 1	$ (12)	$ 360
Three months ended June 30, 2017	$ 57	$ 105	$ 105	$ 34	$ 46	$ 5	$ (12)	$ 340

(a) Includes International, BETM and generation eliminations of $2 million in 2018 and $1 million in 2017.

Operations and maintenance expense increased by $20 million for the three months ended June 30, 2018, compared to the same period in 2017, due to the following:

	(In millions)
2017 proceeds and 2018 payments in settlement of certain legal matters	$ 33
Increase in operations and maintenance due to the gain on sale of the Jewett Mine dragline in 2017	18
Increased deactivation costs primarily at Dunkirk	7
Increase in major maintenance primarily due to outages at W.A. Parish and Big Cajun II	6
Decrease in NRG Yield operations and maintenance expense due to lower costs related to forced outages at Walnut Creek in 2018 compared to 2017, as well as lower losses on disposal of assets at Walnut Creek and El Segundo	(5)
Decrease in East/West operations and maintenance expense due to major maintenance at Sunrise in 2017	(5)
Decrease in Renewables operations and maintenance expense primarily from the deconsolidation of Ivanpah	(9)
Decrease in operations and maintenance expense due to cost efficiencies as a result of the Transformation Plan	(25)
	$ 20

Depreciation and amortization

Depreciation and amortization decreased by $33 million for the three months ended June 30, 2018, compared to the three months ended June 30, 2017, driven primarily by the impairment of property, plant and equipment in prior years as well as the deconsolidation of Ivanpah in May 2018.

Impairment Losses

For the three months ended June 30, 2018, the Company recorded impairment losses of $74 million related to the impairment of the Keystone and Conemaugh generating stations, as well and the impairment of the Dunkirk project, as described in Note 7, *Impairments*.

Selling, General and Administrative

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

	Retail	Generation	Renewables	NRG Yield	Corporate	Total
				(In millions)		
Three months ended June 30, 2018	$ 126	$ 55	$ 12	$ 7	$ 11	$ 211
Three months ended June 30, 2017	106	52	14	7	42	221

Selling, general and administrative expenses decreased by $10 million for the three months ended June 30, 2018, compared to the same period in 2017, due to the following:

	(In millions)
Decrease in general and administrative expense from cost initiatives for the Transformation Plan	$ (36)
Prior year fees associated with advisors engaged to assist the Company in its strategic review in 2017	(6)
Increase in bad debt expense primarily from increased usage due to weather	6
Increase in expense for estimated legal settlements	10
Increase in selling and marketing expense associated with costs incurred for margin enhancement initiatives	16
	$ (10)

Reorganization Costs

Reorganization costs of $23 million, primarily related to employee costs, were incurred as part of the Transformation Plan.

Other Income - Affiliate

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

Gain on Sale of Assets

Gain on sale of assets for the three months ended June 30, 2018, consists primarily of the gain on the sale of Canal 3, while the gain on sale of assets for the three months ended June 30, 2017, represents a gain on the sale of land.

Equity in Earnings/(Losses) of Unconsolidated Affiliates

Equity in earnings of consolidated affiliates increased by $21 million for the three months ended June 30, 2018, compared to the three months ended June 30, 2017, which was primarily driven by the equity in earnings recorded in 2018 for Ivanpah after deconsolidation, as well as by prior year losses from Petra Nova Parish Holdings, offset by the prior period HLBV income allocated to the Company's interests in the Utah Portfolio.

Other (Losses)/Income, Net

Other losses for the three months ended June 30, 2018, primarily relate to the loss on deconsolidation of Ivanpah of $22 million. Other income for the three months ended June 30, 2017, primarily relates to dividends received from cost method investments as well as income from pension and postretirement investments.

Interest Expense

NRG's interest expense decreased by $46 million for the three months ended June 30, 2018, compared to the same period in 2017 due to the following:

	(In millions)
Decrease in derivative interest expense from changes in the fair value of interest rate swaps driven by increased interest rates in 2018	$ (35)
Decrease in interest expense related to repurchases of Senior Notes	(9)
Decrease in interest expense related to Ivanpah deconsolidation	(6)
Other	4
	$ (46)

Income Tax Expense

For the three months ended June 30, 2018, NRG recorded an income tax expense of $8 million on pre-tax income of $129 million. For the same period in 2017, NRG recorded an income tax expense of $4 million on pre-tax income of $103 million. The effective tax rate was 6.2% and 3.9% for the three months ended June 30, 2018 and 2017, respectively.

For the three months ended June 30, 2018, NRG's overall effective tax rate was different than the statutory rate of 21% primarily due to the tax benefit for the change in valuation allowance and the generation of PTCs from various wind facilities partially offset by the inclusion of consolidated partnerships and the current state tax expense.

For the three months ended June 30, 2017, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the tax benefit for the change in valuation allowance and the generation of PTCs and ITCs from various wind and solar facilities, respectively, partially offset by the inclusion of consolidated partnerships and current state tax expense.

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests

For the three months ended June 30, 2018 and 2017, net loss attributable to noncontrolling interests and redeemable noncontrolling interests primarily reflects net losses allocated to tax equity investors in tax equity arrangements using the hypothetical liquidation at book value, or HLBV, method, partially offset by NRG Yield, Inc.'s share of net income.

Management's discussion of the results of operations for the six months ended June 30, 2018 and 2017

Electricity Prices

The following table summarizes average on peak power prices for each of the major markets in which NRG operates for the six months ended June 30, 2018 and 2017. The average on-peak power prices have generally increased primarily due to increased heat rates for the six months ended June 30, 2018, as compared to the same period in 2017.

	Average on Peak Power Price ($/MWh)		
	Six months ended June 30,		
Region	**2018**	**2017**	**Change %**
Gulf Coast [(a)]			
ERCOT - Houston [(b)]	$ 33.98	$ 36.86	(8)%
ERCOT - North[(b)]	33.28	25.28	32 %
MISO - Louisiana Hub[(c)]	45.22	43.71	3 %
East/West			
NY J/NYC[(c)]	49.19	37.48	31 %
NEPOOL[(c)]	51.07	33.69	52 %
COMED (PJM)[(c)]	32.54	31.89	2 %
PJM West Hub[(c)]	43.58	32.40	35 %
CAISO - NP15[(c)]	30.05	27.38	10 %
CAISO - SP15[(c)]	31.60	26.87	18 %

(a) Gulf Coast region also transacts in PJM - West Hub.
(b) Average on peak power prices based on real time settlement prices as published by the respective ISOs.
(c) Average on peak power prices based on day ahead settlement prices as published by the respective ISOs.

The following table summarizes average realized power prices for each region in which NRG operates for the six months ended June 30, 2018 and 2017, which reflects the impact of settled hedges.

	Average Realized Power Price ($/MWh)		
	Six months ended June 30,		
Region	**2018**	**2017**	**Change %**
Gulf Coast	$ 34.85	$ 34.25	2%
East/West [(a)]	40.69	40.20	1%

(a) does not include BETM energy revenue of $32 million and $15 million for 2018 and 2017, respectively.

Though the average on peak power prices have increased on average by 19%, average realized prices by region for the Company have generally fluctuated at different rates year-over-year due to the Company's multi-year hedging program.

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, retail 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 below tables present the composition and reconciliation of gross margin and economic gross margin for the six months ended June 30, 2018 and 2017:

	Six months ended June 30, 2018							
		Generation						
(In millions)	Retail	Gulf Coast	East/West[(a)]	Subtotal	Renewables	NRG Yield	Corporate/Eliminations	Total
Energy revenue	$ —	$ 879	$ 362	$ 1,241	$ 156	$ 306	$ (411)	$ 1,292
Capacity revenue	—	135	300	435	—	169	(3)	601
Retail revenue	3,304	—	—	—	—	—	(2)	3,302
Mark-to-market for economic hedging activities	(6)	(275)	(25)	(300)	(5)	—	220	(91)
Contract amortization	—	7	—	7	—	(35)	—	(28)
Other revenue [(b)]	—	128	34	162	48	92	(35)	267
Operating revenue	3,298	874	671	1,545	199	532	(231)	5,343
Cost of fuel	(12)	(454)	(152)	(606)	(1)	(23)	(88)	(730)
Other cost of sales[(c)]	(2,415)	(164)	(90)	(254)	(4)	(14)	509	(2,178)
Mark-to-market for economic hedging activities	446	(7)	(3)	(10)	—	—	(220)	216
Contract and emission credit amortization	—	(12)	(1)	(13)	—	—	—	(13)
Gross margin	**$ 1,317**	**$ 237**	**$ 425**	**$ 662**	**$ 194**	**$ 495**	**$ (30)**	**$ 2,638**
Less: Mark-to-market for economic hedging activities, net	440	(282)	(28)	(310)	(5)	—	—	125
Less: Contract and emission credit amortization, net	—	(5)	(1)	(6)	—	(35)	—	(41)
Economic gross margin	**$ 877**	**$ 524**	**$ 454**	**$ 978**	**$ 199**	**$ 530**	**$ (30)**	**$ 2,554**
Business Metrics								
MWh sold (thousands)[(d)(e)]		25,220	8,110		2,227	3,924		
MWh generated (thousands) [(f)]		23,146	5,463		2,227	4,729		

(a) Includes International, BETM and Generation eliminations.

(b) Renewables other revenue includes $26 million of intercompany revenue to NRG Yield.

(c) Includes purchased energy, capacity and emissions credits.

(d) MWh sold excludes generation at facilities in East/West and NRG Yield that generate revenue under capacity agreements.

(e) Does not include thermal MWh of 18 thousand or MWt of 1,079 thousand for thermal sold by NRG Yield.

(f) Does not include thermal MWh of 47 thousand or MWt of 987 thousand for thermal generated by NRG Yield.

(In millions)	Six months ended June 30, 2017							
		Generation						
	Retail	Gulf Coast	East/West(a)	Subtotal	Renewables	NRG Yield	Corporate/Eliminations	Total
Energy revenue	$ —	$ 868	$ 408	$ 1,276	$ 174	$ 294	$ (501)	$ 1,243
Capacity revenue	—	133	266	399	—	164	(4)	559
Retail revenue	2,939	—	—	—	—	—	7	2,946
Mark-to-market for economic hedging activities	—	41	4	45	3	—	111	159
Contract amortization	(1)	6	—	6	—	(34)	—	(29)
Other revenue (b)	—	102	20	122	36	85	(38)	205
Operating revenue	2,938	1,150	698	1,848	213	509	(425)	5,083
Cost of fuel	(7)	(498)	(170)	(668)	(2)	(18)	31	(664)
Other cost of sales(c)	(2,204)	(157)	(124)	(281)	(5)	(12)	483	(2,019)
Mark-to-market for economic hedging activities	20	(24)	(3)	(27)	—	—	(111)	(118)
Contract and emission credit amortization	—	(14)	(2)	(16)	—	—	—	(16)
Gross margin	**$ 747**	**$ 457**	**$ 399**	**$ 856**	**$ 206**	**$ 479**	**$ (22)**	**$ 2,266**
Less: Mark-to-market for economic hedging activities, net	20	17	1	18	3	—	—	41
Less: Contract and emission credit amortization, net	(1)	(8)	(2)	(10)	—	(34)	—	(45)
Economic gross margin	**$ 728**	**$ 448**	**$ 400**	**$ 848**	**$ 203**	**$ 513**	**$ (22)**	**$ 2,270**
Business Metrics								
MWh sold (thousands)(d)(e)		25,340	9,776		1,974	3,789		
MWh generated (thousands) (f)		23,790	6,096		1,974	4,244		

(a) Includes International, BETM and Generation eliminations.

(b) Renewables other revenue includes $14 million of intercompany revenue to NRG Yield.

(c) Includes purchased energy, capacity and emissions credits.

(d) MWh sold excludes generation at facilities in East/West and NRG Yield that generate revenue under capacity agreements.

(e) Does not include thermal MWh of 18 thousand or MWt of 987 thousand for thermal sold by NRG Yield.

(f) Does not include thermal MWh of 36 thousand or MWt of 987 thousand for thermal generated by NRG Yield.

The table below represents the weather metrics for the six months ended June 30, 2018 and 2017:

Weather Metrics	Six months ended June 30,	
	Gulf Coast	East/West
2018		
CDDs (a)	1,200	283
HDDs (a)	1,142	2,152
2017		
CDDs	1,125	301
HDDs	673	2,008
10-year average		
CDDs	1,062	276
HDDs	1,103	2,206

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

Retail gross margin and economic gross margin

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

(In millions except otherwise noted)	Six months ended June 30, 2018	2017
Retail revenue	$ 3,135	$ 2,813
Supply management revenue	75	84
Capacity revenue	94	42
Customer mark-to-market	(6)	—
Contract amortization	—	(1)
Other	—	—
Operating revenue [(a)]	3,298	2,938
Cost of sales [(b)]	(2,427)	(2,211)
Mark-to-market for economic hedging activities	446	20
Gross Margin	**$ 1,317**	**$ 747**
Less: Mark-to-market for economic hedging activities, net	440	20
Less: Contract amortization, net	—	(1)
Economic Gross Margin	**$ 877**	**$ 728**
Business Metrics		
Mass electricity sales volume — GWh - Gulf Coast	17,745	16,218
Mass electricity sales volume — GWh - All other regions	3,310	2,998
C&I electricity sales volume — GWh - All regions	10,430	10,141
Natural gas sales volumes (MDth)	3,419	1,700
Average Retail Mass customer count (in thousands)	2,926	2,843
Ending Retail Mass customer count (in thousands) [(c)]	3,173	2,887

(a) Includes intercompany sales of $2 million and $2 million in 2018 and 2017, respectively, representing sales from Retail to the Gulf Coast region.
(b) Includes intercompany purchases of $415 million and $502 million in 2018 and 2017, respectively.
(c) The acquisition of XOOM Energy, LLC increased NRG's retail portfolio by approximately 300,000 customers in the aggregate by June 30, 2018.

Retail gross margin increased $570 million and economic gross margin increased $149 million for the six months ended June 30, 2018, compared to the same period in 2017, due to:

	(In millions)
Higher gross margin due to higher revenue of $101 million or approximately $3.00 per MWh, driven by customer product, term and mix offset by higher supply costs of $40 million or approximately $1.25 per MWh, driven primarily by an increase in power prices	$ 61
Higher gross margin from the Business Solutions unit reflecting the early settlement of capacity obligations for 2018	34
Higher gross margin due to an increase in load of 1,495,000 MWh driven by more favorable weather conditions in 2018 as compared to 2017	46
Higher gross margin due to higher volumes driven by higher average customer counts primarily driven by the XOOM acquisition in June 2018	8
Increase in economic gross margin	$ 149
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	420
Increase in contract amortization	1
Increase in gross margin	**$ 570**

Generation gross margin and economic gross margin

Generation gross margin decreased $194 million and economic gross margin increased $130 million, both of which include intercompany sales, during the six months ended June 30, 2018, compared to the same period in 2017.

The tables below describe the decrease in Generation gross margin and the increase in economic gross margin:

Gulf Coast Region

	(In millions)
Higher gross margin due to a 10% increase in average realized prices in South Central and a 2% increase in average realized prices in Texas	$ 65
Higher gross margin from sales of NOx emission credits	35
Higher capacity margins due to an 15% increase in load demand in the South Central business	29
Lower energy margin due to a 14% increase in supply cost on load contracts	(36)
Lower capacity revenue due to the cancellation of the Greens Bayou RMR agreement in 2017	(14)
Other	(3)
Increase in economic gross margin	$ 76
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(299)
Increase in contract and emission credit amortization	3
Decrease in gross margin	**$ (220)**

East/West

	(In millions)
Higher gross margin due to a 88% increase in New England cleared capacity pricing	$ 34
Higher gross margin due to a 23% increase in PJM cleared capacity pricing which relates to the first full period of capacity performance product pricing	29
Higher gross margin from commercial optimization activities	15
Higher gross margin by BETM due to higher gains in congestion strategies	14
Higher gross margin due to a net overall increase in capacity volumes sold in New York	11
Lower gross margin due to a 31% decrease in capacity pricing in New York of $30 million and decreases in capacity pricing and volumes due to the Long Beach capacity toll expiration in July 2017 of $9 million	(39)
Lower gross margin due to lower load contracted prices coupled with lower contracted volumes	(13)
Lower gross margin due to a 10% decrease in generation volumes due to timing of planned and unplanned outages at Midwest Generation and Arthur Kill, offset by favorable fuel costs	(10)
Higher gross margin due to insurance proceeds from outages of $14 million in 2018, compared to business interruption proceeds of $8 million in 2017	6
Other	7
Increase in economic gross margin	$ 54
Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	(29)
Increase in contract and emission credit amortization	1
Increase in gross margin	**$ 26**

Renewables gross margin and economic gross margin

Renewables gross margin decreased $12 million and economic gross margin decreased $4 million for the six months ended June 30, 2018, compared to the same period in 2017. This was driven by the deconsolidation of Ivanpah in May 2018, offset in part by additional distributed solar projects reaching commercial operations in late 2017 and early 2018.

NRG Yield gross margin and economic gross margin

NRG Yield gross margin increased $16 million and economic gross margin increased $17 million for the six months ended June 30, 2018, compared to the same period in 2017. The increase is due primarily to a 3% increase in volume generated by wind projects, primarily in connection with higher wind resource at the Alta Wind projects, as well as a 5% increase in solar generation, primarily at CVSR in connection with higher insolation and higher plant availability at Walnut Creek and El Segundo.

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 $84 million during the six months ended June 30, 2018, compared to the same period in 2017.

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

	Six months ended June 30, 2018					
		Generation				
	Retail	Gulf Coast	East/West	Renewables	Eliminations[(a)]	Total
	(In millions)					
Mark-to-market results in operating revenues						
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (1)	$ (86)	$ (8)	$ —	$ 31	$ (64)
Net unrealized (losses)/gains on open positions related to economic hedges	(5)	(189)	(17)	(5)	189	(27)
Total mark-to-market (losses)/gains in operating revenues	$ (6)	$ (275)	$ (25)	$ (5)	$ 220	$ (91)
Mark-to-market results in operating costs and expenses						
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 104	$ (3)	$ (7)	$ —	$ (31)	$ 63
Reversal of acquired gain positions related to economic hedges	(1)	—	—	—	—	(1)
Net unrealized gains/(losses) on open positions related to economic hedges	343	(4)	4	—	(189)	154
Total mark-to-market gains/(losses) in operating costs and expenses	$ 446	$ (7)	$ (3)	$ —	$ (220)	$ 216

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

	Six months ended June 30, 2017					
		Generation				
	Retail	Gulf Coast	East/West	Renewables	Eliminations[(a)]	Total
	(In millions)					
Mark-to-market results in operating revenues						
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (1)	$ (8)	$ (37)	$ —	$ 89	$ 43
Net unrealized gains on open positions related to economic hedges	1	49	41	3	22	116
Total mark-to-market gains in operating revenues	$ —	$ 41	$ 4	$ 3	$ 111	$ 159
Mark-to-market results in operating costs and expenses						
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 76	$ (7)	$ 2	$ —	$ (89)	$ (18)
Reversal of acquired loss positions related to economic hedges	1	—	—	—	—	1
Net unrealized losses on open positions related to economic hedges	(57)	(17)	(5)	—	(22)	(101)
Total mark-to-market gains/(losses) in operating costs and expenses	$ 20	$ (24)	$ (3)	$ —	$ (111)	$ (118)

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

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

For the six months ended June 30, 2018, the $91 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 the value of open positions as a result of ERCOT heat rate expansion and increases in ERCOT electricity prices. The $216 million gain in operating costs and expenses from economic hedge positions was driven primarily by an increase in value of open positions as a result of ERCOT heat rate expansion and increases in ERCOT electricity prices, as well as the reversal of previously recognized unrealized losses on contracts that settled during the period.

For the six months ended June 30, 2017, the $159 million gain in operating revenues from economic hedge positions was driven primarily by the increase in value of open positions as a result of decreases in PJM power prices, New York capacity prices, and natural gas prices, as well as the reversal of previously recognized unrealized losses on contracts that settled during the period. The $118 million loss in operating costs and expenses from economic hedge positions was driven primarily by the decrease in value of open positions as a result of decreases in coal and natural gas prices, as well as the reversal of previously recognized unrealized gains on contracts that settled during the period.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the six months ended June 30, 2018 and 2017. The realized and unrealized financial and physical trading results are included in operating revenue within the Generation segment. The Company's trading activities are subject to limits within the Company's Risk Management Policy and are primarily transacted through BETM.

	Six months ended June 30,	
(In millions)	**2018**	**2017**
Trading gains/(losses)		
Realized	$ 40	$ 28
Unrealized	13	(2)
Total trading gains	$ 53	$ 26

Operations and Maintenance Expense

		Generation						
	Retail	**Gulf Coast**	**East/West(a)**	**Renewables**	**NRG Yield**	**Corporate**	**Eliminations**	**Total**
				(In millions)				
Six months ended June 30, 2018	$ 96	$ 307	$ 204	$ 53	$ 94	$ 2	$ (26)	$ 730
Six months ended June 30, 2017	$ 114	$ 250	$ 200	$ 63	$ 98	$ 9	$ (22)	$ 712

(a) Includes International, BETM and generation eliminations of $3 million in 2018 and $2 million in 2017.

Operations and maintenance expense increased by $18 million for the six months ended June 30, 2018, compared to the same period in 2017, due to the following:

	(In millions)
2017 proceeds and 2018 payments in settlement of certain legal matters	$ 33
Increase in operations and maintenance due to the gain on sale of the Jewett Mine dragline in 2017	18
Increase in major maintenance primarily due to outages at W.A. Parish and Big Cajun II	32
Increased deactivation costs primarily at Dunkirk	10
Decrease in operations and maintenance expense due to cost efficiencies as a result of the Transformation Plan(a)	(60)
Decrease in Renewables operations and maintenance expense primarily from the deconsolidation of Ivanpah	(10)
Decrease in NRG Yield operations and maintenance expense due to lower costs related to forced outages at Walnut Creek in 2018 compared to 2017, as well as lower losses on disposal of assets at Walnut Creek and El Segundo	(5)
	$ 18

(a) Approximately $36 million of additional cost savings were achieved in the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, as the savings became permanent through the Transformation Plan.

Depreciation and amortization

Depreciation and amortization decreased by $55 million for the six months ended June 30, 2018, compared to the same period in 2017, driven primarily by the impairment of property, plant and equipment in prior years as well as the deconsolidation of Ivanpah in May 2018.

Impairment Losses

For the six months ended June 30, 2018, the Company recorded impairment losses of $74 million related to the impairment of the Keystone Conemaugh generating stations, as well as the impairment of the Dunkirk project as described in Note 7, *Impairments*.

Selling, General and Administrative

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

	Retail		Generation		Renewables		NRG Yield		Corporate		Total
							(In millions)				
Six months ended June 30, 2018	$	241	$	106	$	22	$	13	$	20	$ 402
Six months ended June 30, 2017		225		111		27		12		106	481

Selling, general and administrative expenses decreased by $79 million for the six months ended June 30, 2018, compared to the same period in 2017.

	(In millions)
Decrease in general and administrative expense from cost initiatives for the Transformation Plan[a]	$ (104)
Prior year fees associated with advisors engaged to assist the Company in its strategic review in 2017	(20)
Prior year fees for advisors and other consultants engaged to assist the Company with GenOn's ability to continue as a going concern	(11)
Increase in bad debt expense primarily from increased usage due to weather	14
Increase in expense for estimated legal settlements	10
Increase in selling and marketing expense associated with costs incurred for margin enhancement initiatives	32
	$ (79)

(a) Approximately $22 million of additional cost savings were achieved in the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, as the savings became permanent through the Transformation Plan.

Reorganization Costs

Reorganization costs of $43 million, primarily related to employee costs, were incurred as part of the Transformation Plan during the six months ended June 30, 2018.

Other Income - Affiliate

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

Gain on Sale of Assets

Gain on sale of assets for the six months ended June 30, 2018, consists primarily of the gain on the sale of Canal 3, while the gain on sale of assets for the six months ended June 30, 2017, represents a gain on the sale of land.

Equity in (Losses)/Earnings of Unconsolidated Affiliates

Equity in earnings of consolidated affiliates increased by $14 million for the six months ended June 30, 2018, compared to the six months ended June 30, 2017, which was primarily driven by the equity in earnings recorded in 2018 for Ivanpah after deconsolidation, as well as by prior year losses from Petra Nova Parish Holdings, offset by the prior period HLBV income allocated to the Company’s interests in the Utah Portfolio.

Other (Losses)/Income, Net

Other losses for the six months ended June 30, 2018, primarily relate to the loss on deconsolidation of Ivanpah of $22 million. Other income for the six months ended June 30, 2017, primarily relates to primarily relates to dividends received from cost method investments as well as income from pension and postretirement investments.

Interest Expense

NRG's interest expense decreased by $102 million for the six months ended June 30, 2018, compared to the same period in 2017 due to the following:

	(In millions)
Decrease in derivative interest expense from changes in the fair value of interest rate swaps driven by increased interest rates in 2018	$ (75)
Decrease in interest expense related to repurchases of Senior Notes	(20)
Decrease in interest expense related to Ivanpah deconsolidation	(6)
Other	(1)
	$ (102)

Income Tax Expense

For the six months ended June 30, 2018, NRG recorded an income tax expense of $7 million on pre-tax income of $361 million. For the same period in 2017, NRG recorded an income tax benefit of $1 million on a pre-tax loss of $71 million. The effective tax rate was 1.9% and 1.4% for the six months ended June 30, 2018 and 2017, respectively.

For the six months ended June 30, 2018, NRG's overall effective tax rate was different than the statutory rate of 21% primarily due to the tax benefit for the change in valuation allowance and the generation of PTCs from various wind facilities partially offset by the inclusion of consolidated partnerships and the current state tax expense.

For the six months ended June 30, 2017, NRG's overall effective tax rate was different than the statutory rate of 35% primarily due to the tax expense for the change in valuation allowance, current state tax expense partially offset by the generation of PTCs and ITCs from various wind and solar facilities, respectively.

Net loss attributable to noncontrolling interests and redeemable noncontrolling interests

For the six months ended June 30, 2018 and 2017, net loss attributable to noncontrolling interests and redeemable noncontrolling interests primarily reflects net losses allocated to tax equity investors in tax equity arrangements using the hypothetical liquidation at book value, or HLBV, method, partially offset by NRG Yield, Inc.'s share of net income.

Liquidity and Capital Resources

Liquidity Position

As of June 30, 2018 and December 31, 2017, NRG's liquidity, excluding collateral received, was approximately $2.5 billion and $3.2 billion, respectively, comprised of the following:

(In millions)	June 30, 2018	December 31, 2017
Cash and cash equivalents:		
NRG excluding NRG Yield	$ 850	$ 843
NRG Yield and subsidiaries	130	148
Restricted cash - operating	43	71
Restricted cash - reserves [(a)]	243	437
Total	1,266	1,499
Total credit facility availability	1,222	1,711
Total liquidity, excluding collateral received	$ 2,488	$ 3,210

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

For the six months ended June 30, 2018, total liquidity, excluding collateral funds deposited by counterparties, decreased by $722 million. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading *Cash Flow Discussion*. Cash and cash equivalents at June 30, 2018, were predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

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

Sources of Liquidity

The principal sources of liquidity for NRG's future operating and capital expenditures are expected to be derived from cash on hand, cash flows from operations, cash proceeds from future sales of assets, including sales to NRG Yield, Inc. and under the Transformation Plan, and financing arrangements, as described in Note 8, *Debt and Capital Leases*, to this Form 10-Q and Note 12, *Debt and Capital Leases*, to the Company's 2017 10-K. The Company's financing arrangements consist mainly of the Senior Credit Facility, the Senior Notes, the NRG Yield 2019 Convertible Notes, the NRG Yield 2020 Convertible Notes, the Yield Operating LLC senior unsecured notes, the NRG Yield, Inc. revolving credit facility, and project-related financings.

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

On February 6, 2018, NRG and Global Infrastructure Partners, or GIP, entered into a purchase and sale agreement for GIP to purchase NRG's ownership in NRG Yield, Inc. and NRG's renewables platform for cash of $1.375 billion, subject to certain adjustments. The purchase and sale agreement includes the sale of all of NRG's ownership in NRG Yield, Inc., NRG's renewable energy development and operations platforms and NRG's renewable energy non-ROFO backlog and pipeline.

In connection with the transaction, the Company entered into a Consent and Indemnity Agreement with NRG Yield, Inc. and GIP setting forth key terms and conditions of NRG Yield, Inc.'s consent to the transaction. As part of the Consent and Indemnity Agreement, NRG has agreed to indemnify GIP and NRG Yield, Inc. and its project companies for any increase in property taxes at the California-based solar projects resulting from the transaction.

The transaction is subject to certain closing conditions, approvals and consents. As of July 31, 2018, all regulatory approvals have been received, however certain significant consents and waivers remain pending, and the Company expects the transaction to close in the second half of 2018. Upon the closing of the transaction, NRG’s interest in the Ivanpah asset will no longer be part of the NRG Yield ROFO assets.

Sale of South Central Business

On February 6, 2018, NRG and Cleco Energy LLC, or Cleco, entered into a purchase and sale agreement for Cleco to purchase NRG's South Central business for cash of $1.0 billion, subject to certain adjustments. The transaction is expected to close in the second half of 2018 and is subject to certain closing conditions, approvals and consents. The South Central business owns and operates a 3,555 MW portfolio of generation assets in the Gulf Coast region. Upon the closing of the transaction, NRG will enter into a sale leaseback agreement for the Cottonwood plant through May 2025.

Sale of BETM

On August 1, 2018, the Company completed the sale of 100% of its ownership interests in BETM to a third party for $70 million, subject to working capital adjustments. The sale also resulted in the release and return of approximately $119 million of letters of credit, $30 million of parent guarantees, and $4 million of net cash collateral to NRG.

Sales of Assets to NRG Yield, Inc.

On June 19, 2018, the Company completed the sale of the substantially completed assets of the UPMC Thermal Project for cash consideration of $84 million, subject to working capital adjustments.

On March 30, 2018, as part of the Transformation Plan, the Company completed the sale of 100% of its ownership interest in Buckthorn Solar to NRG Yield, Inc. for cash consideration of approximately $42 million.

On February 6, 2018, the Company entered into an agreement with NRG Yield, Inc. to sell 100% of the membership interests in Carlsbad Energy Holdings LLC, which owns the Carlsbad project, a 527-MW natural gas fired project in Carlsbad, CA, pursuant to the ROFO Agreement. The purchase price for the transaction is $365 million in cash consideration, subject to customary working capital and other adjustments. The transaction is expected to close during the fourth quarter of 2018.

Sale of Canal 3

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 is non-recourse to NRG and was transferred to Stonepeak Kestrel in connection with the sale of Canal 3.

Other Asset Sales

During the first half of 2018, the Company completed the sale of various other assets for approximately $7 million.

2023 Term Loan Facility

On March 21, 2018, NRG repriced the 2023 Term Loan Facility, reducing the interest rate margin by 50 basis points to LIBOR plus 1.75% and reducing the LIBOR floor to 0.00%. As a result of the repricing, the Company expects approximately $47 million in interest savings over the remaining life of the loan.

NRG Yield LLC and NRG Yield Operating LLC Revolving Credit Facility

On April 30, 2018, NRG Yield LLC and NRG Yield Operating LLC refinanced the revolving credit facility, which extended the maturity of the facility to April 28, 2023, and decreased the overall cost of borrowing from L+ 2.50% to L+1.75%.

2048 Convertible Senior Notes Issuance

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

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of the Company's assets, excluding assets acquired in the GenOn and EME (including Midwest Generation) acquisitions, assets held by NRG Yield, Inc. and NRG's assets that have project-level financing. NRG uses the first lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or gas used as a proxy for power. To the extent that the underlying hedge positions for a counterparty are out-of-the-money to NRG, the counterparty would have claim under the first lien program. The first lien program limits the volume that can be hedged, not the value of underlying out-of-the-money positions. The first lien program does not require NRG to post collateral above any threshold amount of exposure. Within the first lien structure, the Company can hedge up to 80% of its coal and nuclear capacity, 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 June 30, 2018, 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 June 30, 2018:

Equivalent Net Sales Secured by First Lien Structure [(a)]	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
In MW	264	908	916	765	828	860
As a percentage of total net coal and nuclear capacity [(b)]	6%	19%	20%	16%	18%	18%

(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 EME (including Midwest Generation) acquisition, assets in NRG Yield, Inc. and NRG's assets that have project level financing.

Uses of Liquidity

The Company's requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (i) commercial operations activities; (ii) debt service obligations; (iii) capital expenditures, including repowering and renewable development, and environmental; (iv) allocations in connection with acquisition opportunities, debt repayments, share repurchases, return of capital and dividend payments to stockholders; and (v) costs necessary to execute the Transformation Plan.

Commercial Operations

The Company's commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) margin and collateral required to participate in physical markets and commodity exchanges; (iii) timing of disbursements and receipts (i.e. buying fuel before receiving energy revenues); (iv) initial collateral for large structured transactions; and (v) collateral for project development. As of June 30, 2018, commercial operations had total cash collateral outstanding of $234 million and $953 million outstanding in letters of credit to third parties primarily to support its commercial activities for both wholesale and retail transactions. As of June 30, 2018, total collateral held from counterparties was $76 million in cash and $198 million of letters of credit.

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

Capital Expenditures

The following tables and descriptions summarize the Company's capital expenditures for maintenance, environmental, and growth investments for the six months ended June 30, 2018, and the estimated capital expenditure and growth investments forecast for the remainder of 2018.

	Maintenance	Environmental	Growth Investments [b]	Total
		(In millions)		
Retail	$ 12	$ —	$ 22	$ 34
Generation				
Gulf Coast	70	—	—	70
East/West [a]	15	—	208	223
Renewables	2	—	286	288
NRG Yield	17	—	28	45
Corporate	6	—	25	31
Total cash capital expenditures for the six months ended June 30, 2018	122	—	569	691
Funding from third party equity partners, cash grants and debt financing, net of fees	—	—	(618)	(618)
Other investments [c]	—	—	286	286
Total capital expenditures and investments, net of financings	122	—	237	359
Estimated capital expenditures for the remainder of 2018	99	3	231	333
Funding from third party equity partners, cash grants and debt financing, net of fees	—	—	(73)	(73)
Other investments [c]	—	—	10	10
NRG estimated capital expenditures for the remainder of 2018, net of financings [d]	$ 99	$ 3	$ 168	$ 270

(a) Includes International and BETM
(b) Total cash capital expenditures include $25 million of cost-to-achieve spend associated with the Transformation Plan
(c) Other investments include restricted cash activity and acquisitions
(d) Maintenance capital expenditures includes approximately $66 million for assets to be sold

Growth Investments capital expenditures

For the six months ended June 30, 2018, the Company's growth investment capital expenditures included $266 million for renewable projects, $208 million for repowering projects and $95 million for the Company's other growth projects.

Environmental Capital Expenditures

NRG estimates that environmental capital expenditures from 2018 through 2022 required to comply with environmental laws will be approximately $76 million, which includes $14 million for Midwest Generation.

Common Stock Dividends

The following table lists the dividends paid during the six months ended June 30, 2018:

	Second Quarter 2018	First Quarter 2018
Dividends per Common Share	$ 0.03	$ 0.03

On July 18, 2018, NRG declared a quarterly dividend on the Company's common stock of $0.03 per share, payable August 15, 2018, to stockholders of record as of August 1, 2018 representing $0.12 on an annualized basis.

The Company's common stock dividends are subject to available capital, market conditions, and compliance with associated laws and regulations. The Company expects that, based on current circumstances, comparable cash dividends will continue to be paid in the foreseeable future.

Share Repurchases

In February 2018, the Company's board of directors authorized the Company to repurchase $1 billion of its common stock, with the first $500 million program beginning as soon as permitted. In March 2018, the Company repurchased 3,114,748 shares of NRG common stock for approximately $93 million. During the second quarter of 2018, the Company repurchased 11,748,553 shares of NRG common stock for approximately $407 million, including shares repurchased under the ASR Agreement. In July 2018, the Company received an additional 860,880 shares in connection with the settlement of the ASR Agreement, completing the $500 million of share repurchases. The average cost per share for the total $500 million of shares repurchased was $31.80.

Senior Note Repurchases

In connection with the Transformation Plan, the Company has committed to reduce its debt balance by an additional $640 million to achieve a target net debt to adjusted EBITDA credit ratio of 3.0/1. The following open market senior note repurchases were completed to assist in achieving this target.

In millions, except rates	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	$ 6	$ 6	103.25%
5.750% senior notes due 2028	20	21	99.13%
6.625% senior notes due 2027	20	21	103.06%
Total at August 2, 2018	$ 89	$ 93	

(a) Includes payment for accrued interest.

As discussed in more detail in "Significant Events" in this *Management's Discussion and Analysis of Financial Condition and Results of Operations*, on August 1, 2018, the Company announced that it gave the required notice under the indenture governing its 6.25% Senior Notes due 2022 to redeem for cash $486 million aggregate principal amount of its 2022 Notes on August 31, 2018.

XOOM Energy Acquisition

On June 1, 2018, the Company completed the acquisition of XOOM Energy, LLC, an electricity and natural gas retailer operating in 19 states, Washington, D.C. and Canada for approximately $219 million in cash, inclusive of approximately $54 million in payments for estimated working capital, which is subject to further adjustment. The acquisition increased NRG's retail portfolio by approximately 300,000 customers in the aggregate by June 30, 2018.

Repowerings

Carlsbad — The Company is currently overseeing construction of the Carlsbad project, which when completed will consist of approximately 527 MWs of net generation capacity. On February 6, 2018, the Company entered into an agreement with NRG Yield, Inc. to sell the Carlsbad project pursuant to the ROFO Agreement. The transaction is expected to close during the fourth quarter of 2018.

Puente Power Project — On October 5, 2017, the California Energy Commission, or CEC, the agency responsible for permitting the Puente Power Project, issued a statement on behalf of the committee of two Commissioners overseeing the permitting process stating their intention to issue a proposed decision that would deny a permit for the Puente Power Project. On October 16, 2017, NRG filed a motion to suspend the permitting proceeding for at least six months, which was granted on November 3, 2017. On April 20, 2018, NRG filed a motion requesting an additional extension of the suspension period to coincide with the CPUC's final decision on SCE's application seeking approval of resources procured through its Moorpark RFO, or until June 30, 2019, whichever is sooner.

Cash Flow Discussion

The following table reflects the changes in cash flows for the comparative six-month periods:

	Six months ended June 30, 2018	Six months ended June 30, 2017	Change
	(In millions)		
Net cash provided/(used) by operating activities	$ 524	$ 74	$ 450
Net cash used by investing activities	(1,146)	(545)	(601)
Net cash used by financing activities	423	18	405

Net Cash Provided By Operating Activities

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

	(In millions)
Increase in operating income adjusted for non-cash items	$ 262
Changes in cash collateral in support of risk management activities due to changes in commodity prices	171
Other changes in working capital	(21)
Change in cash from discontinued operations	38
	$ 450

Net Cash Used By Investing Activities

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

	(In millions)
Increase in cash paid for acquisitions in 2018 compared to 2017, primarily from the XOOM acquisition	$ (268)
Increase in capital expenditures for growth investments for solar and repowering projects	(149)
Beginning balance of cash removed due to the deconsolidation of Ivanpah in 2018	(160)
Decrease in proceeds from the sale of investments in 2017 compared to 2018	(17)
Decrease in insurance proceeds for property damage	(18)
Decrease in sales of emissions, net of purchases	(17)
Change in cash from discontinued operations	53
Other	(25)
	$ (601)

Net Cash Provided By Financing Activities

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

	(In millions)
Repurchases of common stock in 2018, from open market repurchases and the ASR Agreement	$ (500)
Increase in payments for short and long-term debt	(318)
Increase in proceeds from the issuance of long-term debt, primarily for the Convertible Notes	659
Change in cash from discontinued operations including long-term deposits in 2017	349
Increase in cash contributions, net of distributions from non-controlling interests in 2018, primarily related to tax equity financings	208
Other	7
	$ 405

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

For the six months ended June 30, 2018, the Company had a total domestic pre-tax book income of $361 million and an immaterial foreign pre-tax book income. As of December 31, 2017, the Company had cumulative domestic Federal NOL carryforwards of $2.8 billion, which will begin expiring in 2026 and cumulative state NOL carryforwards of $2.2 billion for financial statement purposes. In addition, NRG has cumulative foreign NOL carryforwards of $224 million, which do not have an expiration date. Contingent upon GenOn's emergence from bankruptcy, the Company will recognize an estimated $9.7 billion worthless stock deduction for tax purposes.

In addition to these amounts, the Company has $39 million of tax effected uncertain tax benefits. As a result of the Company's tax position, and based on current forecasts, NRG anticipates income tax payments, primarily to state and local jurisdictions, of up to $20 million in 2018.

The Company has recorded a non-current tax liability of $39 million until final resolution with the related taxing authority. The $39 million non-current tax liability for uncertain tax benefits is from positions taken on various state income tax returns, including accrued interest.

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

Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications.

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 June 30, 2018, NRG has several investments in energy and energy-related entities that are accounted for under the equity method of accounting. Several of these investments are variable interest entities for which NRG is not the primary beneficiary. See also Note 9, *Variable Interest Entities, or VIEs,* to this Form 10-Q.

NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $1.2 billion as of June 30, 2018. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Note 16, *Investments Accounted for by the Equity Method and Variable Interest Entities*, to the Company's 2017 Form 10-K.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs, as disclosed in the Company's 2017 Form 10-K. See also Note 8, *Debt and Capital Leases*, and Note 15, *Commitments and Contingencies*, to this Form 10-Q for a discussion of new commitments and contingencies that also include contractual obligations and commercial commitments that occurred during the three and six months ended June 30, 2018.

Fair Value of Derivative Instruments

NRG may enter into power purchase and sales contracts, fuel purchase contracts and other energy-related financial instruments to mitigate variability in earnings due to fluctuations in spot market prices and to hedge fuel requirements at generation facilities or retail load obligations. In addition, in order to mitigate interest rate risk associated with the issuance of the Company's variable rate and fixed rate debt, NRG enters into interest rate swap agreements. The following disclosures about fair value of derivative instruments provide an update to, and should be read in conjunction with, *Fair Value of Derivative Instruments* in Item 7 — *Management's Discussion and Analysis of Financial Condition and Results of Operations*, of the Company's 2017 Form 10-K.

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 June 30, 2018, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at June 30, 2018.

Derivative Activity Gains	**(In millions)**
Fair Value of Contracts as of December 31, 2017	$ 46
Contracts realized or otherwise settled during the period	9
Contracts acquired during the period	11
Changes in fair value	217
Fair Value of Contracts as of June 30, 2018	$ 283

	Fair Value of Contracts as of June 30, 2018				
	Maturity				
Fair value hierarchy (Losses)/Gains	**1 Year or Less**	**Greater than 1 Year to 3 Years**	**Greater than 3 Years to 5 Years**	**Greater than 5 Years**	**Total Fair Value**
	(In millions)				
Level 1	$ (9)	$ (30)	$ (8)	$ (1)	$ (48)
Level 2	10	137	16	15	178
Level 3	141	32	(6)	(14)	153
Total	$ 142	$ 139	$ 2	$ —	$ 283

The Company has elected to present derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company's derivative assets or liabilities are recorded on a separate line item on the balance sheet. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company's portfolio. As discussed in Item 3 - *Quantitative and Qualitative Disclosures About Market Risk, Commodity Price Risk*, to this Form 10-Q, 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 asset and liability position is a better indicator of NRG's hedging activity. As of June 30, 2018, NRG's net derivative asset was $283 million, an increase to total fair value of $237 million as compared to December 31, 2017. This increase was driven by gains in fair value, acquired contracts, and the roll-off of trades that settled during the period.

Based on a sensitivity analysis using simplified assumptions, the impact of a $0.50 per MMBtu increase in natural gas prices across the term of the derivative contracts would result in a decrease of approximately $191 million in the net value of derivatives as of June 30, 2018. The impact of a $0.50 per MMBtu decrease in natural gas prices across the term of derivative contracts would result in an increase of approximately $183 million in the net value of derivatives as of June 30, 2018.

Critical Accounting Policies and Estimates

NRG's discussion and analysis of the financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily 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 has 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.

The Company identifies its most critical accounting policies as those that are the most pervasive and important to the portrayal of the Company's financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain. NRG's critical accounting policies include derivative instruments, income taxes and valuation allowance for deferred tax assets, impairment of long lived assets and investments, goodwill and other intangible assets, and contingencies.

The Company performs its annual test of goodwill impairment during the fourth quarter. The Company tests its long-lived assets for impairment whenever indicators of impairment exist. The Company's annual budget is utilized to determine the cash flows associated with the Company's long-lived assets, which incorporates various assumptions, including the Company's long-term view of natural gas prices and its impact on merchant power prices and fuel costs. The Company's annual budget process is finalized and approved by the Board of Directors in the fourth quarter. It is reasonably possible that the updated long-term cash flows will not support the carrying value of certain assets, and the Company will be required to test such assets for impairment. This could also have a negative impact on the fair value of the reporting units that have goodwill balances. This decrease in power prices could also result in an adverse change in the manner that long-lived assets are used, or result in the Company selling an asset before the end of its previously estimated useful life, at a price that is lower than its carrying amount. Accordingly, if these decreases continue, it is possible that the Company's goodwill or long-lived assets will be impaired.

ITEM 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

NRG is exposed to several market risks in the Company's normal business activities. Market risk is the potential loss that may result from market changes associated with the Company's merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks the Company is exposed to are commodity price risk, interest rate risk, liquidity risk, credit risk and currency exchange risk. The following disclosures about market risk provide an update to, and should be read in conjunction with, Item 7A — *Quantitative and Qualitative Disclosures About Market Risk*, of the Company's 2017 Form 10-K.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities and correlations between various commodities, such as natural gas, electricity, coal, oil and emissions credits. NRG manages the commodity price risk of the Company's merchant generation operations and load serving obligations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales and purchases of electricity and fuel. NRG measures the risk of the Company's portfolio using several analytical methods, including sensitivity tests, scenario tests, stress tests, position reports and VaR. NRG uses a Monte Carlo simulation based VaR model to estimate the potential loss in the fair value of its energy assets and liabilities, which includes generation assets, load obligations and bilateral physical and financial transactions.

The following table summarizes average, maximum and minimum VaR for NRG's commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions, calculated using the VaR model for the three and six months ending June 30, 2018 and 2017:

(In millions)	2018	2017
VaR as of June 30,	$ 54	$ 49
Three months ended June 30,		
Average	$ 59	$ 59
Maximum	68	66
Minimum	52	49
Six months ended June 30,		
Average	59	$ 56
Maximum	69	66
Minimum	48	41

In order to provide additional information for comparative purposes to NRG's peers, the Company also uses VaR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VaR for the derivative financial instruments calculated using the diversified VaR model as of June 30, 2018, for the entire term of these instruments entered into for both asset management and trading was $25 million, primarily driven by asset-backed transactions.

Interest Rate Risk

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

The Company's project subsidiaries enter into interest rate swaps, intended to hedge the risks associated with interest rates on non-recourse project level debt. See Note 12, *Debt and Capital Leases*, of the Company's 2017 Form 10-K for more information on the Company's interest rate swaps.

If all of the above swaps had been discontinued on June 30, 2018, the Company would have owed the counterparties $79 million. Based on the credit ratings of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

NRG has both long and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of June 30, 2018, a 1% change in variable interest rates would result in a $14.3 million change in interest expense on a rolling twelve-month basis.

As of June 30, 2018, the fair value and related carrying value of the Company's debt was $16.2 billion and $16.0 billion respectively. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company's long-term debt by $981 million.

Liquidity Risk

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

Based on a sensitivity analysis for power and gas positions under marginable contracts, a $0.50 per MMBtu change in natural gas prices across the term of the marginable contracts would cause a change in margin collateral posted of approximately $61 million as of June 30, 2018, and a 1 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $44 million as of June 30, 2018. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of June 30, 2018.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. NRG is exposed to counterparty credit risk through various activities including wholesale sales, fuel purchases and retail supply arrangements, and retail customer credit risk through its retail load activities. See Note 4, *Fair Value of Financial Instruments*, to this Form 10-Q for discussions regarding counterparty credit risk and retail customer credit risk, and Note 6, *Accounting for Derivative Instruments and Hedging Activities*, to this Form 10-Q for discussion regarding credit risk contingent features.

Currency Exchange Risk

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

ITEM 4 — CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of NRG's management, including its principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures, as such term is defined in Rules 13a-15(e) or 15d-15(e) of the Exchange Act. Based on this evaluation, the Company's principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this Quarterly Report on Form 10-Q.

Changes in Internal Control over Financial Reporting

There were no changes in NRG's internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred in the quarter ended June 30, 2018 that materially affected, or are reasonably likely to materially affect, NRG's internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

For a discussion of material legal proceedings in which NRG was involved through June 30, 2018, see Note 15, *Commitments and Contingencies*, to this Form 10-Q.

ITEM 1A — RISK FACTORS

Information regarding risk factors appears in Part I, Item 1A, *Risk Factors Related to NRG Energy, Inc.*, in the Company's 2017 Form 10-K. There have been no material changes in the Company's risk factors since those reported in its 2017 Form 10-K.

ITEM 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

In February 2018, the Company's board of directors authorized the Company to repurchase $1 billion of its common stock, with the first $500 million program beginning as soon as permitted. The authorization did not specify an expiration date.

The table below sets forth the information with respect to purchases made by or on behalf of NRG or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act), of NRG's common stock during the quarter ended June 30, 2018.

For the three months ended June 30, 2018	Total Number of Shares Purchased	Average Price Paid per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(b)]
Month #1				
(April 1, 2018 to April 30, 2018)	1,779,530	$ 29.98	1,779,530	$ 853,952,158
Month #2				
(May 1, 2018 to May 31, 2018)	9,969,023	$ 32.69	9,969,023	$ 499,950,111
Month #3				
(June 1, 2018 to June 30, 2018)	—	$ —	—	$ 499,950,111
Total at June 30, 2018	11,748,553		11,748,553	

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

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

ITEM 3 — DEFAULTS UPON SENIOR SECURITIES

See Note 3, *Discontinued Operations and Dispositions*, to the Condensed Consolidated Financial Statements of the Company's 2017 Form 10-K, for a description of events of default by GenOn and GenOn Americas Generation under the GenOn Senior Notes and the GenOn Americas Generation Senior Notes.

ITEM 4 — MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5 — OTHER INFORMATION

None.

ITEM 6 — EXHIBITS

Number	Description	Method of Filing
4.1	Indenture, dated May 24, 2018, among NRG Energy, Inc., the guarantors named therein and Delaware Trust Company, as trustee.	Incorporated herein by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 25, 2018.
4.2	Form of 2.75% Convertible Senior Notes due 2048.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on May 25, 2018.
10.1	Third Amendment Agreement, dated as of May 7, 2018, by and among NRG Energy, Inc., its subsidiaries parties thereto, the lenders from time to time parties thereto and Citicorp North America, Inc., as administrative agent and collateral agent.	Incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 7, 2018.
10.2	NRG Energy, Inc. Amended and Restated Executive Change-in-Control and General Severance Plan for Tier IA and Tier IIA Executives (Amended and Restated Effective April 1, 2018).	Filed herewith.
31.1	Rule 13a-14(a)/15d-14(a) certification of Mauricio Gutierrez.	Filed herewith.
31.2	Rule 13a-14(a)/15d-14(a) certification of Kirkland B. Andrews.	Filed herewith.
31.3	Rule 13a-14(a)/15d-14(a) certification of David Callen.	Filed herewith.
32	Section 1350 Certification.	Furnished herewith.
101 INS	XBRL Instance Document.	Filed herewith.
101 SCH	XBRL Taxonomy Extension Schema.	Filed herewith.
101 CAL	XBRL Taxonomy Extension Calculation Linkbase.	Filed herewith.
101 DEF	XBRL Taxonomy Extension Definition Linkbase.	Filed herewith.
101 LAB	XBRL Taxonomy Extension Label Linkbase.	Filed herewith.
101 PRE	XBRL Taxonomy Extension Presentation Linkbase.	Filed herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NRG ENERGY, INC.
(Registrant)

/s/ MAURICIO GUTIERREZ

Mauricio Gutierrez
Chief Executive Officer
(Principal Executive Officer)

/s/ KIRKLAND B. ANDREWS

Kirkland B. Andrews
Chief Financial Officer
(Principal Financial Officer)

/s/ DAVID CALLEN

David Callen
Chief Accounting Officer
(Principal Accounting Officer)

Date: August 2, 2018

NRG Energy, Inc.

Amended and Restated Executive Change-in-Control and General Severance Plan for Tier IA and Tier IIA Executives

(Amended and Restated Effective April 1, 2018)

Contents

NRG Energy, Inc.
Amended and Restated Executive Change-in-Control
and General Severance Plan for Tier I and Tier II Executives

Article 1. Establishment and Term of the Plan

1.1 Establishment of the Plan. NRG Energy, Inc. (hereinafter referred to as the "Company") hereby adopts this plan known as the "NRG Energy, Inc. Amended and Restated Executive Change-in-Control and General Severance Plan for Tier I and Tier II Executives" (the "Plan"). This Plan was amended and restated as of August 1, 2016, and the Company hereby further amends and restates the Plan, effective April 1, 2018. The Plan provides Severance Benefits to Tier IA Executives and Tier IIA Executives of the Company (each an "Executive" and collectively the "Executives") upon certain terminations of employment from the Company.

The Company considers the establishment and maintenance of a sound and vital management to be essential to protecting and enhancing the best interests of the Company and its stockholders. In this connection, the Company recognizes that, as is the case with many publicly held corporations, the possibility of a Change in Control may arise and that such possibility, and the uncertainty and questions which it may raise among management, may result in the departure or distraction of management personnel to the detriment of the Company and its stockholders.

Accordingly, the Board has determined that appropriate steps should be taken to reinforce and encourage the continued attention and dedication of members of the Company's management to their assigned duties without distraction in circumstances arising from the possibility of a Change in Control of the Company.

1.2 Initial Term. This Plan commenced on July 23**,** 2009 (the "Effective Date") and continued for a period of three (3) years (the "Initial Term").

1.3 Successive Periods. The term of this Plan shall automatically be extended for one (1) additional year at the end of the Initial Term, and then again after each successive one (1) year period thereafter (each such one (1) year period following the Initial Term is referred to as a "Successive Period"). The Committee may terminate this Plan at the end of any Successive Period by giving the Executives written notice of intent to terminate the Plan, delivered at least six (6) months prior to the end of such Successive Period. If such notice is properly delivered by the Company, this Plan, along with all corresponding rights, duties, and covenants, shall automatically expire at the end of the Successive Period then in progress.

1.4 Change-in-Control Renewal. Notwithstanding the provisions of Section 1.3 above, in the event that a Change in Control of the Company occurs during any Successive Period, upon the effective date of such Change in Control, the term of this Plan shall automatically and irrevocably be renewed for a period of two (2) years from the effective date of such Change in Control. Further, this Plan may be assigned to the successor in such Change in Control, as further provided in Article 9 herein. This Plan shall thereafter automatically terminate following such two (2) year Change-in-Control renewal period; provided that such termination shall not affect or diminish the rights of Executives who become entitled to benefits or payments under this Plan.

Article 2. Definitions

Whenever used in this Plan, the following terms shall have the meanings set forth below and, when the meaning is intended, the initial letter of the word is capitalized.

(a)"**Accountants**" shall have the meaning set forth in Article 6.

(b)"**Base Salary**" means the greater of the Executive's annual rate of salary, whether or not deferred, at: (i) the Effective Date of Termination or (ii) at the date of the Change in Control.

(c)"**Beneficiary**" means the persons or entities designated or deemed designated by the Executive pursuant to Section 9.6 herein.

(d)“**Board**” means the Board of Directors of the Company.

(e)“**Cause**” shall mean one or more of the following:

(i)the Executive’s willful misconduct or gross negligence in the performance of the Executive’s duties to the Company that has or could reasonably be expected to have an adverse effect on the Company;

(ii)the Executive’s willful failure to perform the Executive’s duties to the Company (other than as a result of death or a physical or mental incapacity);

(iii)indictment for, conviction of, or pleading of guilty or nolo contendere to, a felony or any crime involving moral turpitude;

(iv)the Executive’s performance of any material act of theft, fraud, malfeasance or dishonesty in connection with the performance of the Executive’s duties to the Company;

(v)breach of any written agreement between the Executive and the Company, or a violation of the Company’s code of conduct or other written policy; or

(vi) any other material breach of Article 5 of this Plan.

For purposes of this Plan, there shall be no termination for Cause pursuant to subsections (i) through (vi) above, unless a written notice, containing a detailed description of the grounds constituting Cause hereunder, is delivered to the Executive stating the basis for the termination. Upon receipt of such notice, the Executive shall be given thirty (30) days to fully cure and remedy the neglect or conduct that is the basis of such claim, provided that the Executive’s right to cure shall not apply if there are egregious, habitual or repeated breaches by the Executive.

(f)“**Change-in-Control Severance Benefits**” means the Severance Benefit described in Section 3.2.

(g)“**Change in Control**” shall mean the first to occur of any of the following events:

(i)Any “person” (as that term is used in Sections 13 and 14(d)(2) of the Securities Exchange Act of 1934 (“Exchange Act”)) becomes the “Beneficial Owner” (as that term is used in Section 13(d) of the Exchange Act), directly or indirectly, of fifty percent (50%) or more of the Company’s capital stock entitled to vote in the election of directors, excluding any "person" who becomes a "beneficial owner" in connection with a Business Combination (as defined in paragraph (iii) below) which does not constitute a Change in Control under said paragraph (iii); or

(ii)Persons who on the Effective Date constitute the Board (the “Incumbent Directors”) cease for any reason, including without limitation, as a result of a tender offer, proxy contest, merger, or similar transaction, to constitute at least a majority thereof, provided that any person becoming a director of the Company subsequent to the Effective Date shall be considered an Incumbent Director if such person’s election or nomination for election was approved by a vote of at least two-thirds (2/3) of the Incumbent Directors; but provided further, that any such person whose initial assumption of office is in connection with an actual or threatened election contest relating to the election of members of the Board or other actual or threatened solicitation of proxies or consents by or on behalf of a “person” (as defined in Sections 13(d) and 14(d) of the Exchange Act) other than the Board, including by reason of agreement intended to avoid or settle any such actual or threatened contest or solicitation, shall not be considered an Incumbent Director; or

(iii) Consummation of a reorganization, merger, consolidation, or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, all or substantially all of the individuals and entities who were the beneficial owners of outstanding voting securities of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more than fifty percent (50%) of the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the company resulting from such Business Combination (including, without limitation, a company which, as a result of such transaction, owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination, of the outstanding voting securities of the Company; or

(iv) The stockholders of the Company approve any plan or proposal for the liquidation or dissolution of the Company.

(h) "**Code**" means the United States Internal Revenue Code of 1986, as amended, and any successors thereto.

(i) "**Committee**" means the Compensation Committee of the Board or any other committee appointed by the Board to perform the functions of the Compensation Committee.

(j) "**Company**" means NRG Energy, Inc., a Delaware corporation, or any successor thereto as provided in Article 8 herein.

(k) "**Confidential Information**" shall have the meaning set forth in Article 5(a).

(l) "**Delay Period**" shall have the meaning set forth in Section 3.4(b).

(m) "**Disability**" shall mean a disability that would entitle Executive to payment of monthly disability payments under any Company long-term disability plan.

(n) "**Effective Date**" means the commencement date of this Plan as specified in Section 1.2 of this Plan.

(o) "**Effective Date of Termination**" means the date on which a Qualifying Termination occurs, as defined hereunder, which triggers the payment of Severance Benefits hereunder.

(p) "**Executive**" shall have the meaning set forth in Section 1.1.

(q) "**Former Parent Company**" means Xcel Energy, Inc., a Minnesota corporation, or any successor thereto.

(r) "**General Severance Benefits**" means the Severance Benefit described in Section 3.3.

(s) "**Good Reason**" shall mean without the Executive's express written consent the occurrence of any one or more of the following:

(i) The Company materially reduces the amount of the Executive's then current Base Salary or the target for his annual bonus; or

(ii) A material reduction in the Executive's benefits under or relative level of participation in the Company's employee benefit or retirement plans, policies, practices, or arrangements in which the Executive participates as of the Effective Date of this Plan; or

(iii) A material diminution in the Executive's title, authority, duties, or responsibilities or the assignment of duties to the Executive which are materially inconsistent with his position; or

(iv) The failure of the Company to obtain in writing the obligation to perform or be bound by the terms of this Plan by any successor to the Company or a purchaser of all or substantially all of the assets of the Company within fifteen (15) days after a merger, consolidation, sale, or similar transaction.

For purposes of this Plan, the Executive is not entitled to assert that his termination is for Good Reason unless the Executive gives the Board written notice of the event or events which are the basis for such claim within ninety (90) days after the event or events occur, describing such claim in reasonably sufficient detail to allow the Board to address the event or events and a period of not less than thirty (30) days after to cure or fully remedy the alleged condition.

(t) "**Initial Term**" shall have the meaning set forth in Section 1.2.

(u) "**Noncompete Period**" shall have the meaning set forth in Article 5(c).

(v) "**Notice of Termination**" shall mean a written notice which shall indicate the specific termination provision in this Plan relied upon, and shall set forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Executive's employment under the provision so indicated.

(w) "**Original Plan**" shall mean the NRG Energy, Inc. Amended and Restated Executive Change-in-Control and General Severance Plan, amended and restated effective December 9, 2008.

(x) "**Parachute Payment Ratio**" shall have the meaning set forth in Article 6.

(y) "**Plan**" shall have the meaning set forth in Section 1.1.

(z) "**Qualifying Termination**" means:

(i) If such event occurs within the time period that is six (6) months immediately prior to, or twenty-four (24) months immediately following a Change in Control:

(A) An involuntary termination of the Executive's employment by the Company for reasons other than Cause, death, or Disability pursuant to a Notice of Termination delivered to the Executive by the Company; or

(B) A voluntary termination by the Executive for Good Reason pursuant to a Notice of Termination delivered to the Company by the Executive; or

(ii) If such event occurs at any other time:

(A) An involuntary termination of the Executive's employment by the Company for reasons other than Cause, death, or Disability pursuant to a Notice of Termination delivered to the Executive by the Company.

(aa) "**Release Effective Date**" shall have the meaning set forth in Section 3.1(d).

(bb) "**Severance Benefits**" means the payment of Change-in-Control or General (as appropriate) Severance compensation as provided in Article 3 herein.

(cc)“**Specified Employee**” means any Executive described in Section 409A(a)(2)(B)(i) of the Code.

(dd)“**Successive Period**” shall have the meaning set forth in Section 1.3.

(ee)“**Third Party Information**” shall have the meaning set forth in Article 5(a).

(ff)“**Tier IA Executives**” shall include those employees of the Company with the Job Level of EVP prior to the Change in Control, or such other employee who is designated as a Tier IA Executive in the Company’s human resources information system immediately prior to the Change in Control other than the CEO.

(gg)“**Tier IIA Executives**” shall include those employees of the Company with the Job Level of SVP prior to the Change in Control, or such other employee who is designated as a Tier IIA Executive in the Company’s human resources information system immediately prior to the Change in Control.

(hh)“**Total Payments**” shall have the meaning set forth in Article 6.

(ii)“**Work Product**” shall have the meaning set forth in Article 5(b).

Article 3. Severance Benefits

3.1 Right to Severance Benefits

(a)**Change-in-Control Severance Benefits**. The Executive shall be entitled to receive from the Company Change-in-Control Severance Benefits, as described in Section 3.2 herein, if a Qualifying Termination of the Executive’s employment has occurred within six (6) months immediately prior to or twenty-four (24) months immediately following a Change in Control of the Company.

(b)**General Severance Benefits**. The Executive shall be entitled to receive from the Company General Severance Benefits, as described in Section 3.3 herein, if a Qualifying Termination of the Executive’s employment has occurred other than during the six (6) months immediately prior to or twenty-four (24) months immediately following a Change in Control.

(c)**No Severance Benefits**. The Executive shall not be entitled to receive Severance Benefits if the Executive’s employment with the Company ends for reasons other than a Qualifying Termination.

(d)**General Release and Acknowledgement of Restrictive Covenants**. As a condition to receiving Severance Benefits under either Section 3.2 or 3.3 herein, the Executive shall be obligated to execute a general waiver and release of claims in favor of the Company, its current and former affiliates and stockholders, and the current and former directors, officers, employees, and agents of the Company in a form drafted by and acceptable to the Company, and any revocation period for such release must have expired, in each case within sixty (60) days of the date of termination. The date upon which the executed release is no longer subject to revocation shall be referred to herein as the “Release Effective Date”. The Executive must also execute a notice acknowledging the restrictive covenants in Article 5 within sixty (60) days of the date of termination. Notwithstanding the foregoing, the Administrator shall have discretion to reasonably enlarge (but not reduce) the time period for the Executive to consider the waiver and release of claims and to acknowledge the restrictive covenants, if the Administrator determines that such enlargement is necessary for the Executive to effectively review the Release or to secure the advice and input of counsel. Any payments under Section 3.2 or 3.3 shall commence only after execution of the release and acknowledgement, and in the manner provided in Section 3.4. Notwithstanding the foregoing, in any instance in which the period in which the Executive could adopt a release (along with its accompanying revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

(e)**No Duplication of Severance Benefits**. If the Executive becomes entitled to Change-in-Control Severance Benefits, the Severance Benefits provided for under Section 3.2 hereunder shall be in lieu of all other Severance Benefits provided to the Executive under the provisions of this Plan and any other Company-related or Former Parent Company-related severance plans, programs, or agreements including, but not limited to, the Severance Benefits under Section 3.3 herein. Likewise, if the Executive becomes entitled to General Severance Benefits, the Severance Benefits provided under Section 3.3 hereunder shall be in lieu of all other Severance Benefits provided to the Executive under the provisions of this Plan and any other Company-related severance plans, programs, or other agreements including, but not limited to, the Severance Benefits under Section 3.2 herein**.**

3.2 Description of Change-in-Control Severance Benefits. In the event the Executive becomes entitled to receive Change-in-Control Severance Benefits, as provided in Section 3.1 herein, the Company shall provide the Executive with the following:

(a)A lump-sum amount, paid upon the date that is sixty (60) calendar days following the Effective Date of Termination, equal to the Executive's unpaid Base Salary, accrued vacation pay, unreimbursed business expenses, and all other items earned by and owed to the Executive through and including the Effective Date of Termination, provided that to the extent the payment of any amounts pursuant to this Section 3.2(a) does not constitute "deferred compensation" for purposes of Code Section 409A, such amounts shall be paid upon the Release Effective Date. Notwithstanding the foregoing, in any instance in which the period in which the Executive could adopt a release (along with its accompanying revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

(b)A lump-sum amount, paid upon the date that is sixty (60) calendar days following the Effective Date of Termination, equal to: (i) two and ninety-nine one-hundredths (2.99) for Tier I Executives, or (ii) two (2) for Tier II Executives times the sum of the following: (A) the Executive's Base Salary and (B) the Executive's annual target bonus opportunity in the year of termination; provided that to the extent the payment of any amounts pursuant to this Section 3.2(b) does not constitute "deferred compensation" for purposes of Code Section 409A, such amounts shall be paid upon the Release Effective Date. Notwithstanding the foregoing, in any instance in which the period in which the Executive could adopt a release (along with its accompanying revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

(c)A lump-sum amount, paid upon the date that is sixty (60) calendar days following the Effective Date of Termination, equal to the Executive's then current target bonus opportunity established under the bonus plan in which the Executive is then participating, for the plan year in which a Qualifying Termination occurs, adjusted on a pro rata basis based on the number of days the Executive was actually employed during the bonus plan year in which the Qualifying Termination occurs, provided that to the extent the payment of any amounts pursuant to this Section 3.2(c) does not constitute "deferred compensation" for purposes of Code Section 409A, such amounts shall be paid upon the Release Effective Date. Notwithstanding the foregoing, in any instance in which the period in which the Executive could adopt a release (along with its accompanying revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

(d)Payment of all or a portion of the Executive's cost to participate in COBRA medical and dental continuation coverage for eighteen (18) months following the Executive's Effective Date of Termination, such that Executive maintains the same coverage level and cost, on an after tax basis, as in effect immediately prior to the Executive's Effective Date of Termination.

Notwithstanding the above, these medical benefits shall be discontinued prior to the end of the stated continuation period in the event the Executive is eligible to receive substantially similar benefits from a subsequent employer, as determined solely by the Committee in good faith. For purposes of enforcing this offset provision, the Executive shall be deemed to have a duty to keep the Company informed as to the terms and conditions of any subsequent employment and the corresponding benefits earned from such employment, and shall provide, or cause to provide, to the Company in writing correct, complete, and timely information concerning the same.

(e)Treatment of outstanding long-term incentives shall be in accordance with the governing plan document and award agreements, if any.

3.3 Description of General Severance Benefits. In the event the Executive becomes entitled to receive General Severance Benefits as provided in Section 3.1(b) herein, the Company shall provide the Executive with the following:

(a)A lump-sum amount, paid upon the date that is sixty (60) calendar days following the Effective Date of Termination, equal to the Executive's unpaid Base Salary, accrued vacation pay, unreimbursed business expenses, and all other items earned by and owed to the Executive through and including the Effective Date of Termination; provided that to the extent the payment of any amounts pursuant to this Section 3.3(a) does not constitute "deferred compensation" for purposes of Code Section 409A, such amounts shall be paid upon the Release Effective Date. Notwithstanding the foregoing, in any instance in which the period in which the Executive could adopt a release (along with its accompanying revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

(b)A lump-sum amount, paid upon the date that is sixty (60) calendar days following the Effective Date of Termination, equal to one and one-half (1.5) times the Executive's Base Salary; provided that to the extent the payment of any amounts pursuant to this Section 3.3(b) does not constitute "deferred compensation" for purposes of Code Section 409A, such amounts shall be paid upon the Release Effective Date. Notwithstanding the foregoing, in any instance in which the period in which the Executive could adopt a release (along with its accompanying revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

(c)Payment of all or a portion of the Executive's cost to participate in COBRA medical and dental continuation coverage for eighteen (18) months following the Executive's Effective Date of Termination, such that Executive maintains the same coverage level and cost, on an after tax basis, as in effect immediately prior to the Executive's Effective Date of Termination.

Notwithstanding the above, these medical insurance benefits shall be discontinued prior to the end of the stated continuation period in the event the Executive is eligible to receive substantially similar benefits from a subsequent employer, as determined solely by the Committee in good faith. For purposes of enforcing this offset provision, the Executive shall be deemed to have a duty to keep the Company informed as to the terms and conditions of any subsequent employment and the corresponding benefits earned from such employment, and shall provide, or cause to provide, to the Company in writing correct, complete, and timely information concerning the same.

(d)Treatment of outstanding long-term incentives shall be in accordance with the governing plan document and award agreements, if any.

3.4 Coordination with Release and Delay Required by Code Section 409A.

(a)To the extent any continuing benefit (or reimbursement thereof) to be provided is not "deferred compensation" for purposes of Code Section 409A, then such benefit shall commence or be made immediately after the Release Effective Date. To the extent any continuing benefit (or reimbursement thereof) to be provided is "deferred compensation" for purposes of Code Section 409A, then such benefits shall be reimbursed or commence upon the sixtieth (60) day following the Executive's termination of employment. The delayed benefits shall in any event expire at the time such benefits would have expired had the benefits commenced immediately upon Executive's termination of employment.

(b)Notwithstanding any other payment schedule provided herein to the contrary, if the Executive is deemed on the date of termination to be a Specified Employee, then, once the release and acknowledgement required by Section 3.1(d) is executed and delivered and no longer subject to revocation, any payment that is considered deferred compensation under Code Section 409A payable on account of a "separation from service" shall be made on the date which is the earlier of (A) the expiration of the six (6)-month period measured from the date of such "separation from service" of the Executive, and (B) the date of the Executive's death (the "Delay Period") to the extent required under Code Section 409A. Upon the expiration of the Delay Period, all payments delayed pursuant to this Section 3.4(b) (whether they would have otherwise been payable in a single sum or in installments in the absence of such delay) shall be paid to the Executive in a lump sum, and any remaining payments due under this Plan shall be paid or provided in accordance with the normal payment dates specified for them herein.

Article 4.Ineligibility

4.1 Comparable Position.

Subject to the provisions of Article 2(z)(i)(B), the Company may offer an Executive a comparable position, may require an Executive to apply for a comparable position with the Company or any affiliate, or may reassign an Executive to a new position or a reclassification of the Executive's current position; provided, that all such positions shall be located within reasonably the same geographic area where the Executive is located at the time a Qualifying Termination occurs. The Company shall determine, in its sole and reasonable discretion, what constitutes a comparable position under this Section 4.1. The failure of an Executive to accept the position, or apply for the position when required by the Company will render the Executive ineligible for benefits under this Plan.

4.2 Other Circumstances.

Unless otherwise determined by the Committee, an Executive shall also be ineligible for benefits under this Plan if the Executive:

(a)voluntarily terminates employment or retires prior to the Qualifying Termination;

(b)is receiving long-term Disability benefits;

(c)is entitled to any other compensation or benefit which is determined, in the Company's sole discretion, to supersede the Severance Benefits offered under this Plan;

(d)was discharged for Cause; or

(e)was offered employment by a successor employer or by a purchaser in the event of a spin-off or sale of a subsidiary, business unit or business assets of the Company or its subsidiaries, whether or not the Executive accepts or declines the offer of employment, unless the Company has agreed in the applicable sale document or otherwise that such offer will not be disqualifying.

Article 5. Restrictive Covenants

In the event the Executive becomes entitled to receive Change-in-Control Severance Benefits as provided in Section 3.2 herein or General Severance Benefits as provided in Section 3.3 herein, the following shall apply:

(a)**Confidential Information**. The Executive acknowledges that the information, observations, and data (including trade secrets) obtained by him while employed by the Company concerning the business or affairs of the Company or any of its affiliates ("Confidential Information") are the property of the Company or such affiliate. Therefore, except in the course of the Executive's duties to the Company or as may be compelled by law or appropriate legal process, the Executive agrees that he shall not disclose to any person or entity or use for his own purposes any Confidential Information or any confidential or proprietary information of other persons or entities in the possession of the Company and its affiliates ("Third Party Information"), without the prior written consent of the Board, unless and to the extent that the Confidential Information or Third Party Information becomes generally known to and available for use by the public other than as a result of the Executive's acts or omissions. Except in the course of the Executive's duties to Company or as may be compelled by law or appropriate legal process, the Executive will not, during his employment with the Company, or permanently thereafter, directly or indirectly use, divulge, disseminate, disclose, lecture upon, or publish any Confidential Information, without having first obtained written permission from the Board to do so. As of the Effective Date of Termination, the Executive shall deliver to the Company, or at any other time the Company may reasonably request, all memoranda, notes, plans, records, reports, computer files, disks and tapes, printouts and software and other documents and data (and copies thereof) embodying or relating to Third Party Information, Confidential Information, or the business of the Company, or its affiliates which he may then possess or have under his control.

(b)**Intellectual Property, Inventions, and Patents**. The Executive acknowledges that all discoveries, concepts, ideas, inventions, innovations, improvements, developments, methods, trade secrets, designs, analyses, drawings, reports, patent applications, copyrightable work and mask work (whether or not including any Confidential Information), and all registrations or applications related thereto, all other proprietary information and all similar or related information (whether or not patentable) which may relate to the Company's or any of its affiliates' actual or anticipated business, research and development, or existing or future products or services and which are conceived, developed, or made by the Executive (whether alone or jointly with others) while employed by the Company and its affiliates ("Work Product"), belong to the Company or such affiliate. The Executive shall promptly disclose such Work Product to the Board and, at the Company's expense, perform all actions reasonably requested by the Board (whether during or after the Executive's employment with the Company) to establish and confirm such ownership (including, without limitation, assignments, consents, powers of attorney, and other instruments). The Executive acknowledges that all applicable Work Product shall be deemed to constitute "works made for hire" under the U.S. Copyright Act of 1976, as amended. To the extent any Work Product is not deemed a work made for hire, then the Executive hereby assigns to the Company or such affiliate all right, title, and interest in and to such Work Product, including all related intellectual property rights.

The Executive is hereby advised that the above paragraph regarding the Company's and its affiliates' ownership of Work Product does not apply to any invention for which no equipment, supplies, facilities, or trade secret information of the Company or any affiliate was used and which was developed entirely on the Executive's own time, unless: (i) the invention relates to the business of the Company or any affiliate or to the Company's or any affiliate's actual or demonstrably anticipated research or development, or (ii) the invention results from any work performed by the Executive for the Company or any affiliate.

(c)**Noncompete**. In further consideration of the compensation to be paid to the Executive hereunder, the Executive acknowledges that during the course of his employment with the Company and its affiliates he shall become familiar with the Company's trade secrets and with other Confidential Information concerning the Company and its affiliates and that his services shall be of special, unique, and extraordinary value to the Company and its affiliates, and therefore, the Executive agrees that, during the Executive's employment with the Company and for one (1) year thereafter (the "Noncompete Period"), the Executive shall not directly or indirectly own any interest in, manage, control, participate in, consult with, render services for, be employed in an executive, managerial, or administrative capacity by, or in any manner engage in any company engaged in the business of wholesale or retail power generation, or any other business which competes with the businesses of the Company or its affiliates, as such businesses exist or are in process during the Executive's employment with the Company, within any geographical area in which the Company or its affiliates engage or have definitive plans to engage in such businesses. Nothing herein shall prohibit the Executive from being a passive owner of not more than two percent (2%) of the outstanding stock of any class of a corporation which is publicly traded, so long as the Executive has no active participation in the business of such corporation. Notwithstanding the foregoing, the provisions of this Article 5(c) shall not apply in the case of termination of the Executive's employment pursuant to any material breach of the Company's obligations under Article 3 which remains uncured for more than twenty (20) days after notice is received from the Executive of such breach, which such notice shall include a detailed description of the grounds constituting such breach. Further, notwithstanding the foregoing, given American Bar Association Model Rule of Professional Conduct 5.6, and analogous state rules regulating the professional conduct of lawyers, the provisions of this Article 5(c) shall not apply solely with respect to the provision of legal services by Executive if Executive is a licensed attorney.

(d)**Nonsolicitation**. During the Noncompete Period, the Executive shall not directly or indirectly through another person or entity: (i) induce or attempt to induce any employee of the Company or any of its affiliates to leave the employ of the Company or such affiliate, or in any way interfere with the relationship between the Company or any affiliate and any employee thereof; (ii) hire any person who was an employee of the Company or any affiliate during the last six (6) months of the Executive's employment with the Company; or (iii) induce or attempt to induce any customer, supplier, licensee, licensor, franchisee, or other business relation of the Company or any affiliate to cease doing business with the Company or such affiliate, or in any interfere with the relationship between any such customer, supplier, licensee, or business relation and the Company or any affiliate (including, without limitation, making any negative or disparaging statements or communications regarding the Company or its affiliates).

(e)**Nondisparagement.** During the Noncompete Period, Executive shall not disparage the Company, its subsidiaries and parents, and their respective officers, managers and employees, or make any public statement (whether written or oral) reflecting negatively on the Company, its subsidiaries and parents, and their respective officers, managers, and employees, including, but not limited to, any matters relating to the operation or management of the Company, irrespective of the truthfulness or falsity of such statement, except as may otherwise be required by applicable law or compelled by process of law. By way of example and not limitation, Executive agrees that he will not make any written or oral statements that cast in a negative light the services, qualifications, business operations or business ethics of the Company or its employees. Nothing in this Article 5(e) shall restrict either party's ability to: (i) consult with counsel, (ii) make truthful statements under oath or to a government agency or official, or (iii) take any legal action with respect to his employment or termination of employment with the Company.

(f)**Duration, Scope, or Area**. If, at the time of enforcement of this Article 5, a court shall hold that the duration, scope, or area restrictions stated herein are unreasonable under circumstances then existing, the parties agree that the maximum duration, scope, or area reasonable under such circumstances shall be substituted for the stated duration, scope, or area and that the court shall be allowed to revise the restrictions contained herein to cover the maximum period, scope, and area permitted by law. Article 5(c) and 5(d) shall not apply to any Executive whose principal work location for the Company at the time of termination was in the State of California.

(g)**Company Enforcement**. In the event of a breach or a threatened breach by the Executive of any of the provisions of this Article 5, the Company would suffer irreparable harm, and in addition and supplementary to other rights and remedies existing in its favor, the Company shall be entitled to specific performance and/or injunctive or other equitable relief from a court of competent jurisdiction in order to enforce or prevent any violations of the provisions hereof (without posting a bond or other security). In addition, in the event of a breach or violation by the Executive of Article 5(c), the

Noncompete Period shall be automatically extended by the amount of time between the initial occurrence of the breach or violation and when such breach or violation has been duly cured.

Article 6. Certain Change in Control Payments

Notwithstanding any provision of the Plan to the contrary, if any payments or benefits an Executive would receive from the Company under the Plan or otherwise in connection with the Change in Control (the "Total Payments") (a) constitute "parachute payments" within the meaning of Section 280G of the Code, and (b) but for this Article 6, would be subject to the excise tax imposed by Section 4999 of the Code, then such Executive will be entitled to receive either (i) the full amount of the Total Payments or (ii) a portion of the Total Payments having a value equal to One Dollar ($1) less than three (3) times such individual's "base amount" (as such term is defined in Section 280G(b)(3)(A) of the Code), whichever of (i) and (ii), after taking into account applicable federal, state, and local income taxes and the excise tax imposed by Section 4999 of the Code, results in the receipt by such employee on an after-tax basis, of the greatest portion of the Total Payments. Any determination required under this Article 6 shall be made in writing by the Company's independent certified public accountants appointed prior to any change in ownership (as defined under Section 280G(b)(2) of the Code) or tax counsel selected by such accountants (the "Accountants"), whose determination shall be conclusive and binding for all purposes upon the applicable Executive. For purposes of making the calculations required by this Article 6, the Accountants may make reasonable assumptions and approximations concerning applicable taxes and may rely on reasonable, good-faith interpretations concerning the application of Sections 280G and 4999 of the Code. If there is a reduction pursuant to this Article 6 of the Total Payments to be delivered to the applicable Executive, the payment reduction contemplated by the preceding sentence shall be implemented by determining the Parachute Payment Ratio (as defined below) for each "parachute payment" and then reducing the "parachute payments" in order beginning with the "parachute payment" with the highest Parachute Payment Ratio. For "parachute payments" with the same Parachute Payment Ratio, such "parachute payments" shall be reduced based on the time of payment of such "parachute payments," with amounts having later payment dates being reduced first. For "parachute payments" with the same Parachute Payment Ratio and the same time of payment, such "parachute payments" shall be reduced on a pro rata basis (but not below zero) prior to reducing "parachute payments" with a lower Parachute Payment Ratio. For purposes hereof, the term "Parachute Payment Ratio" shall mean a fraction the numerator of which is the value of the applicable "parachute payment" for purposes of Section 280G of the Code and the denominator of which is the actual present value of such payment.

Article 7. Legal Fees and Notice

7.1 Payment of Legal Fees. Except as otherwise agreed to by the parties, the Company shall pay the Executive for costs of litigation or other disputes including, without limitation, reasonable attorneys' fees incurred by the Executive in asserting any claims or defenses under this Plan, except that the Executive shall bear his own costs of such litigation or disputes (including, without limitation, attorneys' fees) if the court (or arbitrator) finds in favor of the Company with respect to any claims or defenses asserted by the Executive.

7.2 Notice. Any notices, requests, demands, or other communications provided for by this Plan shall be sufficient if in writing and if sent by registered or certified mail to the Executive at the last address he or she has filed in writing with the Company or, in the case of the Company, at its principal offices.

Article 8. Successors and Assignment

8.1 Successors to the Company. The Company shall require any successor (whether direct or indirect, by purchase, merger, reorganization, consolidation, acquisition of property or stock, liquidation, or otherwise) of all or a significant portion of the assets of the Company by agreement, in form and substance satisfactory to the Executive, to expressly assume and agree to perform under this Plan in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place. Regardless of whether such agreement is executed, the terms of this Plan shall be binding upon any successor in accordance with the operation of law and such successor shall be deemed the "Company" for purposes of this Plan.

8.2 Assignment by the Executive. This Plan shall inure to the benefit of and be enforceable by the Executive's personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees, and legatees. If the Executive dies while any amount would still be payable to him or her hereunder had he or she continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with the terms of this Plan to the Executive's Beneficiary. If the Executive has not named a Beneficiary, then such amounts shall be paid to the Executive in accordance with the Company's regular payroll practices or to the Executive's estate, as applicable.

Article 9. Miscellaneous

9.1 Employment Status. Except as may be provided under any other agreement between the Executive and the Company, the employment of the Executive by the Company is "at will" and may be terminated by either the Executive or the Company at any time, subject to applicable law.

9.2 Code Section 409A.

(a) All expenses or other reimbursements under this Plan shall be made on or prior to the last day of the taxable year following the taxable year in which such expenses were incurred by the Executive (provided that if any such reimbursements constitute taxable income to the Executive, such reimbursements shall be paid no later than March 15th of the calendar year following the calendar year in which the expenses to be reimbursed were incurred), and no such reimbursement or expenses eligible for reimbursement in any taxable year shall in any way affect the expenses eligible for reimbursement in any other taxable year.

(b) For purposes of Code Section 409A, the Executive's right to receive any installment payment pursuant to this Plan shall be treated as a right to receive a series of separate and distinct payments.

(c) Whenever a payment under this Plan specifies a payment period with reference to a number of days (e.g., "payment shall be made within thirty (30) days following the date of termination"), the actual date of payment within the specified period shall be within the sole discretion of the Company.

(d) A termination of employment shall not be deemed to have occurred for purposes of any provision of this Plan providing for the payment of any amounts or benefits upon or following a termination of employment unless such termination is also a "separation from service" within the meaning of Code Section 409A and, for purposes of any such provision of this Plan, references to a "termination," "termination of employment" or like terms shall mean "separation from service."

(e) Notwithstanding any other provision of this Plan to the contrary, in no event shall any payment under this Plan that constitutes "deferred compensation" for purposes of Code Section 409A be subject to offset unless otherwise permitted by Code Section 409A.

(f) Notwithstanding any provisions in this Plan to the contrary, whenever a payment under this Plan may be made upon the Release Effective Date, and the period in which the Executive could adopt the release (along with its accompany revocation period) crosses calendar years, no payments shall be made until the succeeding calendar year.

9.3 Entire Plan. This Plan supersedes any prior agreements or understandings, oral or written, between the parties hereto, with respect to the subject matter hereof, and constitutes the entire agreement of the parties with respect thereto. Without limiting the generality of the foregoing sentence, this Plan completely supersedes any and all prior employment agreements entered into by and between the Company and the Executive, and all amendments thereto, in their entirety. Notwithstanding the foregoing, if the Executive has entered into any agreements or commitments with the Company with regard to Confidential Information, noncompetition, nonsolicitation, or nondisparagement, such agreements or commitments will remain valid and will be read in harmony with this Plan to provide maximum protection to the Company. For the avoidance of doubt, the Original Plan shall remain outstanding, provided that following the

Effective Date no additional employees shall become participants in the Original Plan and in no event shall any employee be entitled to participate in both this Plan and the Original Plan.

9.4 Severability. In the event that any provision or portion of this Plan shall be determined to be invalid or unenforceable for any reason, the remaining provisions of this Plan shall be unaffected thereby and shall remain in full force and effect.

9.5 Tax Withholding. The Company may withhold from any benefits payable under this Plan all federal, state, city, or other taxes as may be required pursuant to any law or governmental regulation or ruling.

9.6 Beneficiaries. The Executive may designate one (1) or more persons or entities as the primary and/or contingent beneficiaries of any amounts to be received under this Plan.

Such designation must be in the form of a signed writing acceptable to the Board or the Board's designee. The Executive may make or change such designation at any time.

9.7 Payment Obligation Absolute. The Company's obligation to make the payments provided for herein shall be absolute and unconditional, and shall not be affected by any circumstances, including, without limitation, any offset, counterclaim, recoupment, defense, or other right which the Company may have against the Executive or anyone else.

Except as provided in Article 3 of this Plan, the Executive shall not be obligated to seek other employment in mitigation of the amounts payable or arrangements made under any provision of this Plan, and the obtaining of any such other employment shall in no event effect any reduction of the Company's obligations to make the payments and arrangements required to be made under this Plan.

9.8 Contractual Rights to Benefits. Subject to approval and ratification by the Board, this Plan establishes and vests in the Executive a contractual right to the benefits to which he or she is entitled hereunder. However, nothing herein contained shall require or be deemed to require, or prohibit or be deemed to prohibit, the Company to segregate, earmark, or otherwise set aside any funds or other assets, in trust or otherwise, to provide for any payments to be made or required hereunder.

9.9 Modification. No provision of this Plan may be modified, waived, or discharged with respect to any particular Executive unless such modification, waiver, or discharge is agreed to in writing and signed by such Executive and by an authorized member of the Committee, or by the respective parties' legal representatives and successors, provided, however, that the Committee may unilaterally amend this Plan without the Executive's consent if such amendment does not materially adversely alter or impair in any significant manner any rights or obligations of the Executive under the Plan.

9.10 Gender and Number. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine; the plural shall include the singular and the singular shall include the plural.

9.11 Applicable Law. To the extent not preempted by the laws of the United States, the laws of the state of New Jersey shall be the controlling law in all matters relating to this Plan.

IN WITNESS WHEREOF, NRG Energy; Inc. has caused this Plan document to be executed by a duly authorized officer effective as of April 1, 2018.

ATTEST

/s/ Jennifer Wallace

NRG Energy, Inc.

Jennifer Wallace
Senior Vice President, Administration

EXHIBIT 31.1

CERTIFICATION

I, Mauricio Gutierrez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ MAURICIO GUTIERREZ

Mauricio Gutierrez
Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2018

EXHIBIT 31.2

CERTIFICATION

I, Kirkland B. Andrews, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KIRKLAND B. ANDREWS

Kirkland B. Andrews
Chief Financial Officer
(Principal Financial Officer)

Date: August 2, 2018

EXHIBIT 31.3

CERTIFICATION

I, David Callen, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID CALLEN

David Callen
Chief Accounting Officer
(Principal Accounting Officer)

Date: August 2, 2018

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of NRG Energy, Inc. on Form 10-Q for the quarter ended June 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-Q”), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Form 10-Q.

Date: August 2, 2018

/s/ MAURICIO GUTIERREZ
Mauricio Gutierrez
Chief Executive Officer
(Principal Executive Officer)

/s/ KIRKLAND B. ANDREWS
Kirkland B. Andrews
Chief Financial Officer
(Principal Financial Officer)

/s/ DAVID CALLEN
David Callen
Chief Accounting Officer
(Principal Accounting Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of this Form 10-Q or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NRG Energy, Inc. and will be retained by NRG Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.