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

FORM 10-Q

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

For the Quarterly Period Ended: September 30, 2021

☐ **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	**41-1724239**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

910 Louisiana Street Houston Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 537-3000

(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol(s)	Name of Exchange on Which Registered
Common Stock, par value $0.01	NRG	New York Stock Exchange

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 ☒ **No** ☐

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

Yes ☒ **No** ☐

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 ☒ **Accelerated filer** ☐ **Non-accelerated filer** ☐ **Smaller reporting company** ☐ **Emerging growth company** ☐

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

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

Yes ☐ **No** ☒

As of November 4, 2021, there were 244,838,651 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 the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the 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 *Risk Factors*, in Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2020 and the following:

- Business uncertainties related to the acquisition of Direct Energy and NRG's ability to integrate the operations of Direct Energy with its own;
- NRG's ability to obtain and maintain retail market share;
- General economic conditions, changes in the wholesale power and gas markets and fluctuations in the cost of fuel;
- Volatile power and gas supply costs and demand for power and gas;
- Changes in law, including judicial and regulatory decisions;
- Hazards customary to the power production industry and power generation operations, such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that NRG may not have adequate insurance to cover losses as a result of such hazards;
- The effectiveness of NRG's risk management policies and procedures and the ability of NRG's counterparties to satisfy their financial commitments;
- NRG's ability to enter into contracts to sell power or gas and procure fuel on acceptable terms and prices;
- NRG's inability to estimate with any degree of certainty the future impact that COVID-19, any resurgence of COVID-19, or other pandemic may have on NRG's results of operations, financial position, risk exposure and liquidity;
- NRG's ability to successfully integrate, realize cost savings and manage any acquired businesses;
- NRG's ability to engage in successful acquisitions and divestitures, as well as other mergers and acquisitions activity;
- 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;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Government regulation, including changes in market rules, rates, tariffs and environmental laws;
- NRG's ability to develop and innovate new products, as retail and wholesale markets continue to change and evolve;
- 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;
- 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 in the future;
- Operating and financial restrictions placed on NRG and its subsidiaries that are contained in NRG's corporate credit agreements, and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;
- Cyber terrorism and inadequate cybersecurity, data breaches 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;
- The ability of NRG and its counterparties to develop and build new power generation facilities;
- 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 market initiatives, corporate efficiencies, asset strategy, and a range of other programs throughout NRG to reduce costs or generate revenues;
- NRG's ability to successfully evaluate investments and achieve intended financial results in new business and growth initiatives;

- NRG's ability to develop and maintain successful partnering relationships as needed.

Forward-looking statements speak only as of the date they were made and NRG 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 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:

2020 Form 10-K	NRG's Annual Report on Form 10-K for the year ended December 31, 2020
ACE	Affordable Clean Energy
AESO	Alberta Electric System Operator
Agua Caliente	Agua Caliente Solar Project, a 290 MW photovoltaic power station located in Yuma County, Arizona in which NRG owned a 35% interest
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 power prices	Volume-weighted average power prices, net of average fuel costs and reflecting the impact of settled hedges
BTU	British Thermal Unit
Business	NRG Business, which serves business customers
CAA	Clean Air Act
CAISO	California Independent System Operator
CARES Act	Coronavirus Aid, Relief, and Economic Security Act of 2020
CDD	Cooling Degree Day
CFTC	U.S. Commodity Futures Trading Commission
Centrica	Centrica plc
CO_2	Carbon Dioxide
ComEd	Commonwealth Edison
Company	NRG Energy, Inc.
Convertible Senior Notes	As of September 30, 2021, consists of NRG's $575 million unsecured 2.75% Convertible Senior Notes due 2048
Cottonwood	Cottonwood Generating Station, a 1,153 MW natural gas-fueled plant
COVID-19	Coronavirus Disease 2019
CPP	Clean Power Plan
CPUC	California Public Utilities Commission
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
Economic gross margin	Sum of energy revenue, capacity revenue, retail revenue and other revenue, less cost of fuels, purchased power and other cost of sales
EGU	Electric Generating Unit
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESPP	NRG Energy, Inc. Amended and Restated Employee Stock Purchase Plan
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FTRs	Financial Transmission Rights
GAAP	Generally accepted accounting principles in the U.S.
GHG	Greenhouse Gas
Green Mountain Energy	Green Mountain Energy Company
GW	Gigawatts
GWh	Gigawatt Hour
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 upon whether the electricity output measured is gross or net generation. Heat rates are generally expressed as BTU per net kWh
Home	NRG Home, which serves residential customers
HLW	High-level radioactive waste
ICE	Intercontinental Exchange
IESO	Independent Electricity System Operator
ISO	Independent System Operator, also referred to as RTOs
ISO-NE	ISO New England Inc.
Ivanpah	Ivanpah Solar Electric Generation Station, a 393 MW solar thermal power plant located in California's Mojave Desert in which NRG owns 54.5% interest
kWh	Kilowatt-hour
LaGen	Louisiana Generating, LLC
LTIPs	Collectively, the NRG long-term incentive plan ("LTIP") and the NRG GenOn LTIP
MDth	Thousand Dekatherms
Midwest Generation	Midwest Generation, LLC
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MW	Megawatts
MWh	Saleable megawatt hour net of internal/parasitic load megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
Net CONE	Net cost of new entry
Net Exposure	Counterparty credit exposure to NRG, net of collateral
Net Revenue Rate	Sum of retail revenues less TDSP transportation charges
Nodal	Nodal Exchange is a derivatives exchange
NOL	Net Operating Loss
NOx	Nitrogen Oxides
NPNS	Normal Purchase Normal Sale
NRC	U.S. Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
Nuclear Decommissioning Trust Fund	NRG's nuclear decommissioning trust fund assets, which are for the Company's portion of the decommissioning of the STP, Units 1 & 2
Nuclear Waste Policy Act	U.S. Nuclear Waste Policy Act of 1982
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI/OCL	Other Comprehensive Income/(Loss)
Petra Nova	Petra Nova Parish Holdings, LLC
PJM	PJM Interconnection, LLC
PM2.5	Particulate Matter that has a diameter of less than 2.5 micrometers
PPA	Power Purchase Agreement
PUCT	Public Utility Commission of Texas
RCRA	Resource Conservation and Recovery Act of 1976
Receivables Facility	NRG Receivables LLC, a bankruptcy remote, special purpose, wholly-owned indirect subsidiary of the Company's $800 million accounts receivables securitization facility due 2022, which was amended on July 26, 2021
Receivables Securitization Facilities	Collectively, the Receivables Facility and the Repurchase Facility

Repurchase Facility	NRG's $75 million uncommitted repurchase facility related to the Receivables Facility due 2022, which was amended on July 26, 2021
Revolving Credit Facility	The Company's $3.7 billion revolving credit facility due 2024, was amended on May 28, 2019 and August 20, 2020
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Organization, also referred to as ISOs
SEC	U.S. Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
Senior Notes	As of September 30, 2021, NRG's $5.1 billion outstanding unsecured senior notes consisting of $875 million of the 6.625% senior notes due 2027, $821 million of 5.75% senior notes due 2028, $733 million of the 5.25% senior notes due 2029, $500 million of the 3.375% senior notes due 2029, $1.0 billion of the 3.625% senior notes due 2031 and $1.1 billion of the 3.875% senior notes due 2032
Senior Secured First Lien Notes	As of September 30, 2021, NRG’s $2.5 billion outstanding Senior Secured First Lien Notes consists of $600 million of the 3.75% Senior Secured First Lien Notes due 2024, $500 million of the 2.0% Senior Secured First Lien Notes due 2025, $900 million of the 2.45% Senior Secured First Lien Notes due 2027 and $500 million of the 4.45% Senior Secured First Lien Notes due 2029
Services	NRG Services, which primarily includes the services businesses acquired in the Direct Energy Acquisition
SNF	Spent Nuclear Fuel
SO_2	Sulfur Dioxide
SOFR	Secured overnight financing rate
South Central Portfolio	NRG's South Central Portfolio, which owned and operated a portfolio of generation assets consisting of Bayou Cove, Big Cajun-I, Big Cajun-II, Cottonwood and Sterlington, was sold on February 4, 2019. NRG is leasing back the Cottonwood facility through May 2025
STP	South Texas Project — nuclear generating facility located near Bay City, Texas in which NRG owns a 44% interest
STPNOC	South Texas Project Nuclear Operating Company
TDSP	Transmission/distribution service provider
U.S.	United States of America
U.S. DOE	U.S. Department of Energy
VaR	Value at Risk
VIE	Variable Interest Entity
Winter Storm Uri	A major winter and ice storm that had widespread impacts across North America occurring in February 2021

PART I — FINANCIAL INFORMATION

ITEM 1 — CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

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

	Three months ended September 30,		Nine months ended September 30,	
(In millions, except for per share amounts)	**2021**	**2020**	**2021**	**2020**
Operating Revenues				
Total operating revenues	$ 6,609	$ 2,809	$ 19,943	$ 7,066
Operating Costs and Expenses				
Cost of operations (excluding depreciation and amortization shown below)	3,692	2,034	13,496	4,925
Depreciation and amortization	199	99	569	318
Impairment losses	—	29	306	29
Selling, general and administrative costs	318	216	973	592
Provision for credit losses	64	26	715	74
Acquisition-related transaction and integration costs	17	12	81	13
Total operating costs and expenses	4,290	2,416	16,140	5,951
Gain on sale of assets	—	—	17	6
Operating Income	2,319	393	3,820	1,121
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	15	36	23	37
Impairment losses on investments	—	—	—	(18)
Other income, net	8	11	42	52
Loss on debt extinguishment, net	(57)	—	(57)	(1)
Interest expense	(122)	(99)	(374)	(292)
Total other expense	(156)	(52)	(366)	(222)
Income Before Income Taxes	2,163	341	3,454	899
Income tax expense	545	92	840	216
Net Income	1,618	249	2,614	683
Income per Share				
Weighted average number of common shares outstanding — basic	245	244	245	246
Income per Weighted Average Common Share — Basic	$ 6.60	$ 1.02	$ 10.67	$ 2.78
Weighted average number of common shares outstanding — diluted	245	245	245	247
Income per Weighted Average Common Share — Diluted	$ 6.60	$ 1.02	$ 10.67	$ 2.77

See accompanying notes to condensed consolidated financial statements.

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

(In millions)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Net Income	$ 1,618	$ 249	$ 2,614	$ 683
Other Comprehensive (Loss)/Income				
Foreign currency translation adjustments	(11)	4	(6)	2
Defined benefit plans	1	—	20	—
Other comprehensive (loss)/income	(10)	4	14	2
Comprehensive Income	$ 1,608	$ 253	$ 2,628	$ 685

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except share data)	September 30, 2021 (Unaudited)	December 31, 2020 (Audited)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 259	$ 3,905
Funds deposited by counterparties	1,748	19
Restricted cash	14	6
Accounts receivable, net	3,096	904
Inventory	445	327
Derivative instruments	8,528	560
Cash collateral paid in support of energy risk management activities	21	50
Prepayments and other current assets	461	257
Total current assets	14,572	6,028
Property, plant and equipment, net	1,976	2,547
Other Assets		
Equity investments in affiliates	167	346
Operating lease right-of-use assets, net	293	301
Goodwill	1,801	579
Intangible assets, net	2,915	668
Nuclear decommissioning trust fund	957	890
Derivative instruments	2,671	261
Deferred income taxes	1,994	3,066
Other non-current assets	619	216
Total other assets	11,417	6,327
Total Assets	$ 27,965	$ 14,902
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and finance leases	504	1
Current portion of operating lease liabilities	79	69
Accounts payable	1,967	649
Derivative instruments	6,032	499
Cash collateral received in support of energy risk management activities	1,748	19
Accrued expenses and other current liabilities	1,679	678
Total current liabilities	12,009	1,915
Other Liabilities		
Long-term debt and finance leases	7,957	8,691
Non-current operating lease liabilities	257	278
Nuclear decommissioning reserve	316	303
Nuclear decommissioning trust liability	619	565
Derivative instruments	1,489	385
Deferred income taxes	74	19
Other non-current liabilities	1,166	1,066
Total other liabilities	11,878	11,307
Total Liabilities	23,887	13,222
Commitments and Contingencies		
Stockholders' Equity		
Common stock; $0.01 par value; 500,000,000 shares authorized; 423,545,261 and 423,057,848 shares issued and 244,779,313 and 244,231,933 shares outstanding at September 30, 2021 and December 31, 2020, respectively	4	4
Additional paid-in-capital	8,525	8,517
Retained earnings/(accumulated deficit)	971	(1,403)
Treasury stock, at cost 178,765,948 and 178,825,915 shares at September 30, 2021 and December 31, 2020, respectively	(5,230)	(5,232)
Accumulated other comprehensive loss	(192)	(206)
Total Stockholders' Equity	4,078	1,680
Total Liabilities and Stockholders' Equity	$ 27,965	$ 14,902

See accompanying notes to condensed consolidated financial statements.

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

	Nine months ended September 30,	
(In millions)	**2021**	**2020**
Cash Flows from Operating Activities		
Net Income	$ 2,614	$ 683
Adjustments to reconcile net income to cash provided by operating activities:		
Distributions from and equity in earnings of unconsolidated affiliates	8	6
Depreciation and amortization	569	318
Accretion of asset retirement obligations	21	46
Provision for credit losses	715	74
Amortization of nuclear fuel	39	40
Amortization of financing costs and debt discounts	30	23
Loss on debt extinguishment, net	57	1
Amortization of in-the-money contracts, emissions allowances and retirements of RECs	111	60
Amortization of unearned equity compensation	16	17
Net gain on sale and disposal of assets	(29)	(22)
Impairment losses	306	47
Changes in derivative instruments	(4,419)	(7)
Changes in deferred income taxes and liability for uncertain tax benefits	782	202
Changes in collateral deposits in support of energy risk management activities	1,970	96
Changes in nuclear decommissioning trust liability	38	39
Oil lower of cost or market adjustment	—	29
Changes in other working capital	(973)	(266)
Cash provided by operating activities	1,855	1,386
Cash Flows from Investing Activities		
Payments for acquisitions of businesses, net of cash acquired	(3,534)	(277)
Capital expenditures	(219)	(167)
Net sales/(purchases) of emission allowances	6	(15)
Investments in nuclear decommissioning trust fund securities	(460)	(360)
Proceeds from the sale of nuclear decommissioning trust fund securities	424	318
Proceeds from sale of assets, net of cash disposed	198	15
Changes in investments in unconsolidated affiliates	—	2
Cash used by investing activities	(3,585)	(484)
Cash Flows from Financing Activities		
Payments of dividends to common stockholders	(239)	(221)
Payments for share repurchase activity	(9)	(229)
Net receipts/(payments) from settlement of acquired derivatives that include financing elements	396	(6)
Repayments of long-term debt and finance leases	(1,360)	(62)
Proceeds from issuance of long-term debt	1,100	59
Payments for debt extinguishment costs	(48)	—
Payments of debt issuance costs	(18)	(24)
Proceeds from issuance of common stock	1	1
Net repayments of Revolving Credit Facility and Receivables Securitization Facilities	—	(83)
Purchase of and distributions to noncontrolling interests from subsidiaries	—	(2)
Cash used by financing activities	(177)	(567)
Effect of exchange rate changes on cash and cash equivalents	(2)	(2)
Net (Decrease)/Increase in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash	(1,909)	333
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period	3,930	385
Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period	$ 2,021	$ 718

See accompanying notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Additional Paid-In Capital	Retained Earnings/ (Accumulated Deficit)	Treasury Stock	Accumulated Other Comprehensive Loss	Total Stock-holders' Equity
Balance at December 31, 2020	$ 4	$ 8,517	$ (1,403)	$ (5,232)	$ (206)	$ 1,680
Net loss			(82)			(82)
Other comprehensive income					3	3
Equity-based awards activity, net[(a)]		(5)				(5)
Issuance of common stock		1				1
Common stock dividends and dividend equivalents declared[(b)]			(80)			(80)
Balance at March 31, 2021	$ 4	$ 8,513	$ (1,565)	$ (5,232)	$ (203)	$ 1,517
Net income			1,078			1,078
Other comprehensive income					21	21
Shares reissuance for ESPP				2		2
Equity-based awards activity, net		6				6
Common stock dividends and dividend equivalents declared[(b)]			(80)			(80)
Balance at June 30, 2021	$ 4	$ 8,519	$ (567)	$ (5,230)	$ (182)	$ 2,544
Net income			1,618			1,618
Other comprehensive loss					(10)	(10)
Equity-based awards activity, net		6				6
Common stock dividends and dividend equivalents declared[(b)]			(80)			(80)
Balance at September 30, 2021	$ 4	$ 8,525	$ 971	$ (5,230)	$ (192)	$ 4,078

(In millions)	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Loss	Total Stock-holders' Equity
Balance at December 31, 2019	$ 4	$ 8,501	$ (1,616)	$ (5,039)	$ (192)	$ 1,658
Net income			121			121
Other comprehensive loss					(15)	(15)
Repurchase of partners' equity interest in VIE		18				18
Share repurchases				(150)		(150)
Equity-based awards activity, net[(a)]		(21)				(21)
Common stock dividends and dividend equivalents declared[(b)]			(75)			(75)
Balance at March 31, 2020	$ 4	$ 8,498	$ (1,570)	$ (5,189)	$ (207)	$ 1,536
Net income			313			313
Other comprehensive income					13	13
Shares reissuance for ESPP				2		2
Share repurchases				(47)		(47)
Equity-based awards activity, net		6				6
Issuance of common stock		1				1
Common stock dividends and dividend equivalents declared[(b)]			(74)			(74)
Balance at June 30, 2020	$ 4	$ 8,505	$ (1,331)	$ (5,234)	$ (194)	$ 1,750
Net income			249			249
Other comprehensive income					4	4
Equity-based awards activity, net		6				6
Common stock dividends and dividend equivalents declared[(b)]			(75)			(75)
Balance at September 30, 2020	$ 4	$ 8,511	$ (1,157)	$ (5,234)	$ (190)	$ 1,934

(a) Includes $(9) million and $(27) million of equivalent shares purchased in lieu of tax withholding on equity compensation issuances for the quarters ended March 31, 2021 and 2020, respectively

(b) Dividends per common share were $0.325 for the quarters ended September 30, June 30 and March 31, 2021 and $0.30 for the quarters ended September 30, June 30 and March 31, 2020

See accompanying notes to condensed consolidated financial statements.

Note 1 — Nature of Business and Basis of Presentation

General

NRG Energy, Inc., or NRG or the Company, is a consumer services company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to customers by producing and selling energy and related products and services, nation-wide in the U.S. and Canada in a manner that delivers value to all of NRG's stakeholders. The Company sells energy, services, and innovative, sustainable solutions and advisory services to approximately 6 million Home customers under the names NRG, Reliant, Direct Energy, Green Mountain Energy, Stream, and XOOM Energy, as well as other brand names owned by NRG, supported by approximately 23,000 MW of generation, including approximately 4,850 MW of fossil generation assets held for sale as of September 30, 2021 and approximately 1,600 MW of its PJM coal fleet with a retirement date of June 2022.

On January 5, 2021, the Company acquired Direct Energy, which is a leading retail provider of electricity, natural gas, and home and business energy related products and services, as well as a participant in the wholesale gas and power markets, in the U.S. and Canada. Refer to Note 4, *Acquisitions and Dispositions,* for further discussion of the acquisition of Direct Energy. The acquired operations of Direct Energy are integrated into the existing NRG segment structure. Domestic customer and market operations are combined into the corresponding geographical segments of Texas, East and West/Services/Other. The West/Services/Other segment includes activity related to the Canadian operations as well as the services businesses.

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 2020 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 September 30, 2021, and the results of operations, comprehensive income, cash flows and statements of stockholders' equity for the three and nine months ended September 30, 2021 and 2020.

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

Note 2 — Summary of Significant Accounting Policies

Other Balance Sheet Information

The following table presents the accumulated depreciation included in property, plant and equipment, net and accumulated amortization included in intangible assets, net:

(In millions)	September 30, 2021	December 31, 2020
Property, plant and equipment accumulated depreciation	$ 1,543	$ 1,936
Intangible assets accumulated amortization	1,542	1,357

Credit Losses

On January 1, 2020, the Company adopted ASU No. 2016-13, *Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*, or ASU No. 2016-13, using the modified retrospective approach. Following the adoption of the new standard, the Company's process of estimating expected credit losses remains materially consistent with its historical practice.

Retail trade receivables are reported on the balance sheet net of the allowance for credit losses. The Company accrues a provision for current expected credit losses based on (i) estimates of uncollectible revenues by analyzing accounts receivable aging and current and reasonable forecasts of expected economic factors including, but not limited to, unemployment rates and weather-related events, (ii) historical collections and delinquencies, and (iii) counterparty credit ratings for commercial and industrial customers.

The following table represents the activity in the allowance for credit losses for the three and nine months ended September 30, 2021 and 2020:

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	2021	2020	2021	2020
Beginning balance	$ 761	$ 47	$ 67	$ 43
Acquired balance from Direct Energy	—	—	112	—
Provision for credit losses	64	26	715	74
Write-offs	(41)	(19)	(124)	(71)
Recoveries collected	8	3	22	11
Ending balance	$ 792	$ 57	$ 792	$ 57

The increase in the provision for credit losses during the three months ended September 30, 2021, compared to the same period in 2020 was primarily due to the impact of Winter Storm Uri on counterparty credit risk. The increase in the provision for credit losses during the nine months ended September 30, 2021, compared to the same period in 2020 was primarily due to the impacts of Winter Storm Uri on bilateral finance hedging risk of $403 million, counterparty credit risk of $152 million and ERCOT default shortfall payments of $83 million.

Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash

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

(In millions)	September 30, 2021	December 31, 2020
Cash and cash equivalents	$ 259	$ 3,905
Funds deposited by counterparties	1,748	19
Restricted cash	14	6
Cash and cash equivalents, funds deposited by counterparties and restricted cash shown in the statement of cash flows	$ 2,021	$ 3,930

Funds deposited by counterparties consist of cash held by the Company as a result of collateral posting obligations from its counterparties. Though some amounts are segregated into separate accounts, not all funds are contractually restricted. Based on the Company's intention, these funds are not available for the payment of general corporate obligations; however, they are available for liquidity management. 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 within the Company's projects that are restricted for specific uses.

Recent Accounting Developments - Guidance Adopted in 2021

ASU 2019-12 — In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes,* or ASU 2019-12, to simplify various aspects related to accounting for income taxes. The guidance in ASU 2019-12 amends the general principles in Topic 740 to eliminate certain exceptions for recognizing deferred taxes for investment, performing intraperiod allocation and calculating income taxes in interim periods. This ASU also includes guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. The Company adopted the amendments effective January 1, 2021 using the prospective approach. The adoption did not have a material impact on the Company's results of operations, cash flows, or statement of financial position.

Recent Accounting Developments - Guidance Not Yet Adopted

ASU 2020-06 — In August 2020, the FASB issued ASU No. 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40)*, or ASU 2020-06. The guidance in ASU 2020-06 reduces the number of accounting models for convertible debt instruments and convertible preferred stock. In addition, ASU 2020-06 improves and amends the related earnings per share guidance. This standard is effective for fiscal years beginning after December 15, 2021 and interim periods within those fiscal years. The Company is currently in the process of assessing the impact of this guidance on the consolidated financial statements and disclosures.

ASU 2021-08 — In October 2021, the FASB issued ASU No. 2021-08, *Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers*, or ASU 2021-08. Under current GAAP, an acquirer generally recognizes assets acquired and liabilities assumed in a business combination, including contract assets and contract liabilities arising from revenue contracts with customers and other similar contracts that are accounted for in accordance with ASC 606, *Revenue from Contracts with Customers*, or ASC 606, at fair value on the acquisition date. ASU 2021-08 requires that an entity recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606. At the acquisition date, an acquirer should account for the related revenue contracts in accordance with ASC 606 as if it had originated the contracts, which should generally result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. This update also provides certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. The amendments in this update are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years and should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted, including adoption in an interim period. Adoption during an interim period requires retrospective application to all business combinations for which the acquisition date occurs on or after the beginning of the fiscal year that includes the interim period of early application and prospectively to all business combinations that occur on or after the date of initial application. The Company does not expect the adoption of ASU 2021-08 to have a material impact on the consolidated financial statements and disclosures.

Note 3 — Revenue Recognition

Performance Obligations

As of September 30, 2021, estimated future fixed fee performance obligations are $158 million for the remaining three months of fiscal year 2021, and $345 million, $89 million, $37 million and $20 million for the fiscal years 2022, 2023, 2024 and 2025, respectively. Certain performance obligations relate to the fossil generating assets that are planned for sale to Generation Bridge, as further described in Note 4, *Acquisitions and Dispositions.* These performance obligations are for cleared auction MWs in the PJM, ISO-NE, NYISO and MISO capacity auctions and are subject to penalties for non-performance.

Disaggregated Revenues

The following tables represent the Company's disaggregation of revenue from contracts with customers for the three and nine months ended September 30, 2021 and 2020:

(In millions)	**Three months ended September 30, 2021**				
	Texas	**East**	**West/Services/ Other**	**Corporate/ Eliminations**	**Total**
Retail revenue:					
Home[(a)]	*$ 1,776*	*$ 470*	*$ 400*	*$ —*	*$ 2,646*
Business	*727*	*2,228*	*350*	*—*	*3,305*
Total retail revenue	2,503	2,698	750	—	5,951
Energy revenue[(b)]	18	201	113	4	336
Capacity revenue[(b)]	—	172	17	—	189
Mark-to-market for economic hedging activities[(c)]	(1)	(3)	(6)	13	3
Contract amortization	—	(7)	4	—	(3)
Other revenue[(b)]	115	16	6	(4)	133
Total operating revenue	2,635	3,077	884	13	6,609
Less: Lease revenue	—	—	2	—	2
Less: Realized and unrealized ASC 815 revenue	38	76	(8)	14	120
Less: Contract amortization	—	(7)	4	—	(3)
Total revenue from contracts with customers	$ 2,597	$ 3,008	$ 886	$ (1)	$ 6,490

(a) Home includes Services

(b) The following table represents the realized revenues related to derivative instruments that are accounted for under ASC 815 and included in the amounts above:

(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate/ Eliminations**	**Total**
Energy revenue	$ —	$ 38	$ 2	$ 1	$ 41
Capacity revenue	—	42	—	—	42
Other revenue	39	(1)	(4)	—	34

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

(In millions)	**Three months ended September 30, 2020**				
	Texas	**East**	**West/Services/ Other**	**Corporate/ Eliminations**	**Total**
Retail revenue:					
Home[(a)]	*$ 1,633*	*$ 327*	*$ 27*	*$ —*	*$ 1,987*
Business	*288*	*27*	*—*	*—*	*315*
Total retail revenue	1,921	354	27	—	2,302
Energy revenue[(b)]	11	93	117	1	222
Capacity revenue[(b)]	—	158	16	—	174
Mark-to-market for economic hedging activities[(c)]	1	43	(10)	5	39
Other revenue[(b)]	59	18	(1)	(4)	72
Total operating revenue	1,992	666	149	2	2,809
Less: Lease revenue	—	—	5	—	5
Less: Realized and unrealized ASC 815 revenue	10	115	(10)	5	120
Total revenue from contracts with customers	$ 1,982	$ 551	$ 154	$ (3)	$ 2,684

(a) Home includes Services

(b) The following table represents the realized revenues related to derivative instruments that are accounted for under ASC 815 and included in the amounts above:

(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate/ Eliminations**	**Total**
Energy revenue	$ —	$ 23	$ 13	$ (1)	$ 35
Capacity revenue	—	49	—	—	49
Other revenue	9	—	(13)	1	(3)

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

(In millions)	Nine months ended September 30, 2021 Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Retail revenue:					
Home[(a)]	*$ 4,484*	*$ 1,469*	*$ 1,439*	*$ (1)*	*$ 7,391*
Business	*2,091*	*6,560*	*887*	—	*9,538*
Total retail revenue	6,575	8,029	2,326	(1)	16,929
Energy revenue[(c)]	317	428	238	6	989
Capacity revenue[(c)]	—	568	47	—	615
Mark-to-market for economic hedging activities[(d)]	(5)	(53)	(60)	19	(99)
Contract amortization	—	(15)	(4)	—	(19)
Other revenue[(b)(c)]	1,475	45	17	(9)	1,528
Total operating revenue	8,362	9,002	2,564	15	19,943
Less: Lease revenue	—	1	5	—	6
Less: Realized and unrealized ASC 815 revenue	129	193	(73)	20	269
Less: Contract amortization	—	(15)	(4)	—	(19)
Total revenue from contracts with customers	$ 8,233	$ 8,823	$ 2,636	$ (5)	$ 19,687

(a) Home includes Services

(b) Other Revenue in Texas includes ancillary revenues of $1.2 billion driven by high pricing during Winter Storm Uri

(c) The following table represents the realized revenues related to derivative instruments that are accounted for under ASC 815 and included in the amounts above:

(In millions)	Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Energy revenue	$ —	$ 122	$ (4)	$ 2	$ 120
Capacity revenue	—	119	—	—	119
Other revenue	134	5	(9)	(1)	129

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

(In millions)	Nine months ended September 30, 2020 Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Retail revenue:					
Home[(a)]	*$ 3,938*	*$ 926*	*$ 66*	*$ (1)*	*$ 4,929*
Business	*796*	*70*	—	—	*866*
Total retail revenue	4,734	996	66	(1)	5,795
Energy revenue[(b)]	21	157	252	(1)	429
Capacity revenue[(b)]	—	471	47	—	518
Mark-to-market for economic hedging activities[(c)]	1	63	6	8	78
Other revenue[(b)]	172	45	36	(7)	246
Total operating revenue	4,928	1,732	407	(1)	7,066
Less: Lease revenue	—	1	14	—	15
Less: Realized and unrealized ASC 815 revenue	24	239	50	5	318
Total revenue from contracts with customers	$ 4,904	$ 1,492	$ 343	$ (6)	$ 6,733

(a) Home includes Services

(b) The following table represents the realized revenues related to derivative instruments that are accounted for under ASC 815 and included in the amounts above:

(In millions)	Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Energy revenue	$ —	$ 60	$ 42	$ (3)	$ 99
Capacity revenue	—	114	—	—	114
Other revenue	23	2	2	—	27

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

Contract Balances

The following table reflects the contract assets and liabilities included in the Company's balance sheet as of September 30, 2021 and December 31, 2020:

(In millions)	September 30, 2021	December 31, 2020
Deferred customer acquisition costs	$ 124	$ 113
Accounts receivable, net - Contracts with customers	2,955	866
Accounts receivable, net - Derivative instruments	136	33
Accounts receivable, net - Affiliate	5	5
Total accounts receivable, net	$ 3,096	$ 904
Unbilled revenues (included within Accounts receivable, net - Contracts with customers)	$ 1,268	$ 393
Deferred revenues[(a)]	312	60

(a) Deferred revenues from contracts with customers for the nine months ended September 30, 2021 and the year ended December 31, 2020 were approximately $303 million and $31 million, respectively

The revenue recognized from contracts with customers during the nine months ended September 30, 2021 and 2020 relating to the deferred revenue balance at the beginning of each period was $23 million and $13 million, respectively. The revenue recognized from contracts with customers during the three months ended September 30, 2021 and 2020 relating to the deferred revenue balance at the beginning of each period was $162 million and $31 million, respectively. The change in deferred revenue balances during the three and nine months ended September 30, 2021 and 2020 was primarily due to bill credits owed to certain C&I customers, a portion of which is long-term, as a result of power pricing during Winter Storm Uri and the timing difference of when consideration was received and when the performance obligation was transferred.

Note 4 — Acquisitions and Dispositions

Acquisitions

Direct Energy Acquisition

On January 5, 2021 (the "Acquisition Closing Date"), the Company acquired all of the issued and outstanding common shares of Direct Energy, a North American subsidiary of Centrica. Direct Energy is a leading retail provider of electricity, natural gas, and home and business energy related products and services in North America, with operations in all 50 U.S. states and 8 Canadian provinces. The acquisition increased NRG's retail portfolio by over 3 million customers and strengthens its integrated model. It also broadens the Company's presence in the Northeast and into states and locales where it did not previously operate, supporting NRG's objective to diversify its business.

The Company paid an aggregate purchase price of $3.625 billion in cash and an initial purchase price adjustment of $77 million. The Company funded the purchase price using a combination of $715 million of cash on hand, $166 million from a draw on its Revolving Credit Facility (of which $107 million was used to fund acquisition costs and financing fees that are not included in the aggregate purchase price above), as well as approximately $2.9 billion in secured and unsecured corporate debt issued in December 2020. The purchase price adjustment resulted in a reduction of $3 million, which is in negotiation with Centrica. The Company expects to receive this payment from Centrica in 2021. The Company also increased its collective liquidity and collateral facilities by $3.4 billion as of the Acquisition Closing Date to meet the additional liquidity requirements related to the acquisition, as detailed in the following table:

	(In millions)
Available on Acquisition Closing Date	
Revolving Credit Facility commitment increase	$ 802
Revolving Credit Facility new tranche	273
Facility agreement in connection with the sale of pre-capitalized trust securities	874
Available as of December 31, 2020	
Credit default swap facility	150
Revolving accounts receivable financing facility	750
Repurchase facility	75
Bilateral letter of credit facilities	475
Total Increases to Liquidity and Collateral Facilities	$ 3,399

For further discussion see Note 9, *Long-term Debt and Finance Leases,* and also Note 13, *Receivables Securitization and Repurchase Facility,* to the Company's 2020 Form 10-K.

Acquisition costs were $1 million and $24 million for the three and nine months ended September 30, 2021, respectively, and are included in acquisition-related transaction and integration costs in the Company's consolidated statement of operations.

The acquisition has been recorded as a business combination under ASC 805 with identifiable assets acquired and liabilities assumed provisionally recorded at their estimated fair values on the acquisition date. The initial accounting for the business combination is not complete because the evaluation necessary to assess the fair value of certain net assets acquired and the amount of goodwill to be recognized is still in process. The provisional amounts are subject to revision until the evaluations are completed to the extent that additional information is obtained about the facts and circumstances that existed as of the Acquisition Closing Date.

The purchase price is provisionally allocated as follows:

		(In millions)
Current Assets		
Cash and cash equivalents	$	152
Funds deposited by counterparties		21
Restricted cash		9
Accounts receivable, net		1,802
Inventory		106
Derivative instruments		1,014
Cash collateral paid in support of energy risk management activities		233
Prepayments and other current assets		183
Total current assets		3,520
Property, plant and equipment, net		151
Other Assets		
Goodwill[(a)]		1,257
Intangible assets, net:		
Customer relationships[(b)]		1,277
Customer and supply contracts[(b)]		610
Trade names[(b)]		310
Renewable energy credits		124
Total intangible assets, net		2,321
Derivative instruments		531
Other non-current assets		31
Total other assets		4,140
Total Assets	$	7,811
Current Liabilities		
Accounts payable	$	1,120
Derivative instruments		1,266
Cash collateral received in support of energy risk management activities		21
Accrued expenses and other current liabilities		690
Total current liabilities		3,097
Other Liabilities		
Derivative instruments		562
Deferred income taxes		338
Other non-current liabilities		115
Total other liabilities		1,015
Total Liabilities	$	4,112
Direct Energy Purchase Price	$	3,699

(a) Goodwill arising from the acquisition is attributed to the value of the platform acquired and the synergies expected from combining the operations of Direct Energy with NRG's existing businesses. Goodwill was provisionally allocated to the Texas, East, and West/Services/Other segments of $424 million, $663 million and $170 million, respectively. Goodwill expected to be deductible for tax purposes is $337 million

(b) The weighted average amortization period for total amortizable intangible assets is 12 years

Measurement Period Adjustments

The following measurement period adjustments were recognized during the quarter ended September 30, 2021:

(In millions)	Increase/(Decrease)
Assets	
Goodwill	$ 11
Intangible assets, net	(32)
Total decrease in assets	$ (21)
Liabilities	
Accounts payable	$ (270)
Accrued expenses and other current liabilities	248
Deferred income taxes	(1)
Other non-current liabilities	2
Total decrease in liabilities	$ (21)

The measurement period adjustments to the provisional amounts are attributable primarily to refinement of the underlying assumptions used to estimate the fair value of assets acquired and liabilities assumed as more information is obtained about facts and circumstances that existed as of the Acquisition Closing Date.

Fair Value Measurement of Intangible Assets

The provisional fair values of intangible assets as of the Acquisition Closing Date were measured primarily based on significant inputs that are observable and unobservable in the market and thus represent Level 2 and Level 3 measurements, respectively. Significant inputs were as follows:

Customer relationships — Customer relationships, reflective of Direct Energy's customer base, were valued using an excess earning method of the income approach. Under this approach, the Company estimated the present value of expected future cash flows resulting from existing customer relationships, considering attrition and charges for contributory assets (such as net working capital, fixed assets, workforce and trade names) utilized in the business, discounted at an independent power producer peer group's weighted average cost of capital. The customer relationships are amortized to depreciation and amortization, ratably based on discounted future cash flows. The weighted average amortization period is 12 years.

Customer and supply contracts — The fair value of in-market and out-of-market customer and supply contracts were estimated based on contractual terms compared to market prices as of the Acquisition Closing Date. The majority of the contracts were valued using prices provided by external sources, primarily price quotations available through broker or over-the-counter and online exchanges. For contracts for which external sources or observable market quotes were not available, these values were based on valuation techniques including, but not limited to, internal models based on fundamental analysis of the market and extrapolation of the observable market data with similar characteristics. In addition, the Company applied a credit reserve to reflect credit risk, which is calculated based on published default probabilities. The customer and supply contracts are amortized to revenue and cost of operations, respectively, based upon the fair market value, as of the acquisition date, for each delivery month. The weighted average amortization period is 14 years.

Trade names — Trade names were valued using a "relief from royalty" method of the income approach. Under this approach, the fair value is estimated to be the present value of royalties saved because NRG owns the intangible asset and therefore does not have to pay a royalty for its use. The trade names are amortized to depreciation and amortization, on a straight line basis, over a weighted average amortization period of 15 years.

Renewable energy credits — Renewable energy credits were valued based on the market prices as of the Acquisition Closing Date. Renewable energy credits are retired, as required, for the applicable compliance period. They are expensed to cost of operations based on customer usage.

Fair Value Measurement of Derivative Assets and Liabilities

The fair values of derivatives assets and liabilities as of the Acquisition Closing Date were as follows:

	Fair Value			
(In millions)	Total	Level 1	Level 2	Level 3
Derivatives assets	$ 1,545	$ 155	$ 1,272	$ 118
Derivatives liabilities	$ 1,828	$ 207	$ 1,489	$ 132

Refer to Note 5, *Fair Value of Financial Instruments* to this Form 10-Q and Note 5, *Fair Value of Financial Instruments* to the Company's 2020 Form 10-K for discussion on derivative fair value measurements.

Supplemental Information

For the three and nine months ended September 30, 2021 Direct Energy contributed revenue and income before income taxes as follows:

(In millions)	Three months ended September 30, 2021	Nine months ended September 30, 2021
Revenue	$ 3,599	$ 10,718
Income before income taxes	2,010	3,457

Supplemental Pro Forma Financial Information for the nine months ended September 30, 2021 and 2020[(a)]

The following table provides pro forma combined financial information of NRG and Direct Energy, after giving effect to the Direct Energy acquisition and related financing transactions as if they had occurred on January 1, 2020. The pro forma financial information has been prepared for illustrative and informational purposes only, and is not intended to project future operating results or indicative of what our financial performance would have been had the transactions occurred on the date assumed. No effect has been given to operating synergies.

(In millions)	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Total operating revenues	$ 19,932	$ 16,039
Net Income	2,585	832

(a) Pro forma comparative financial information for the three months ended September 30, 2021 and 2020 has not been included as computation of such information is impracticable as Direct Energy's pre-acquisition financial statements for the three months ended September 30, 2020 were not prepared in accordance with GAAP

Amounts above reflect certain pro forma adjustments that were directly attributable to the Direct Energy acquisition. These adjustments include the following:

(i) Income statement effects of fair value adjustments based on the preliminary purchase price allocation including amortization of intangible assets, depreciation of property, plant and equipment and lease expense.

(ii) Interest expense assumes the financing transactions directly attributable to the Direct Energy acquisition occurred on January 1, 2020.

(iii) Removal of Direct Energy historical interest expense associated with related party notes receivable/payable between Direct Energy and Centrica and its subsidiaries, as those notes are assumed to be repaid as of January 1, 2020.

(iv) Elimination of transactions between NRG and Direct Energy.

(v) Adjustments to reflect all acquisition costs occurring during the nine months ended September 30, 2020.

(vi) Tax effects of pro forma adjustments on both periods and shifting the recognition of one time tax benefits resulting from the acquisition from the nine months ended September 30, 2021 to the period ended September 30, 2020.

Midwest Generation Lease Purchase

On September 29, 2020, Midwest Generation acquired all of the ownership interests in the Powerton facility and Units 7 and 8 of the Joliet facility, which were being leased through 2034 and 2030, respectively, for approximately $260 million. The purchase was funded with cash-on-hand. Upon closing the operating lease liability of $148 million was eliminated.

Dispositions

On February 28, 2021, the Company entered into a definitive purchase agreement with Generation Bridge, an affiliate of ArcLight Capital Partners, to sell approximately 4,850 MW of fossil generating assets from its East and West regions of operations for total proceeds of $760 million, subject to standard purchase price adjustments and certain other indemnifications. The purchase price adjustments will include a working capital deduction for cash flows generated of approximately $11 million per month from the beginning of the year until the closing of the transaction, in lieu of cash flows generated during the year. As part of the transaction, NRG is entering into a tolling agreement for its 866 MW Arthur Kill plant in New York City through April 2025. The transaction is expected to close by the end of 2021 and is subject to various closing conditions, approvals and consents, including approval from the NYPSC. The transaction has received FERC approval and approval under the Hart-Scott-Rodino Act.

As of September 30, 2021, the following is classified as held for sale in the Consolidated Balance Sheet:

	(In millions)[a]
Current assets[b]	$ 51
Property, plant and equipment, net	391
Other non-current assets	3
Total non-current assets[c]	394
Total assets held for sale	$ 445
Current liabilities[d]	14
Non-current liabilities[e]	61
Total liabilities held for sale	$ 75

(a) Property, plant and equipment, net for the East and West/Services/Other segments was $242 million and $149 million, respectively. The remaining assets and liabilities were primarily in the East segment
(b) Included in prepayments and other current assets in the Consolidated Balance Sheet
(c) Included in other non-current assets in the Consolidated Balance Sheet
(d) Included in accrued expenses and other current liabilities in the Consolidated Balance Sheet
(e) Included in other non-current liabilities in the Consolidated Balance Sheet

On February 3, 2021, the Company closed on the sale of its 35% ownership in the Agua Caliente solar project to Clearway Energy, Inc. for $202 million. NRG recognized a gain on the sale of $17 million, including cash disposed of $7 million.

The Company completed other asset sales for cash proceeds of $3 million and $15 million during the nine months ended September 30, 2021 and 2020, respectively.

Note 5 — Fair Value of Financial Instruments

For cash and cash equivalents, funds deposited by counterparties, restricted cash, accounts and other receivables, accounts payable, and cash collateral paid and received in support of energy risk management activities, the carrying amounts approximate fair values 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:

	September 30, 2021		December 31, 2020	
(In millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Notes receivable	$ 2	$ 2	$ 2	$ 2
Liabilities:				
Long-term debt, including current portion [a]	8,537	8,897	8,781	9,446

(a) Excludes deferred financing costs, which are recorded as a reduction to long-term debt in 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 certain notes receivable of the Company is based on expected future cash flows discounted at market interest rate and is classified as Level 3 within the fair value hierarchy.

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:

	September 30, 2021			
(In millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Investments in securities (classified within other current and non-current assets)	$ 23	$ 7	$ 16	$ —
Nuclear trust fund investments:				
Cash and cash equivalents	29	29	—	—
U.S. government and federal agency obligations	76	75	1	—
Federal agency mortgage-backed securities	93	—	93	—
Commercial mortgage-backed securities	43	—	43	—
Corporate debt securities	116	—	116	—
Equity securities	503	503	—	—
Foreign government fixed income securities	4	—	4	—
Other trust fund investments (classified within other non-current assets):				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Foreign exchange contracts	1	—	1	—
Commodity contracts	11,198	2,161	8,474	563
Measured using net asset value practical expedient:				
Equity securities — nuclear trust fund investments	93			
Equity securities (classified within other non-current assets)	8			
Total assets	$ 12,188	$ 2,776	$ 8,748	$ 563
Derivative liabilities:				
Commodity contracts	$ 7,521	$ 1,376	$ 5,893	$ 252
Total liabilities	$ 7,521	$ 1,376	$ 5,893	$ 252

	December 31, 2020			
(In millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Investments in securities (classified within other current and non-current assets)	$ 25	$ 10	$ 15	$ —
Nuclear trust fund investments:				
Cash and cash equivalents	23	23	—	—
U.S. government and federal agency obligations	70	69	1	—
Federal agency mortgage-backed securities	89	—	89	—
Commercial mortgage-backed securities	36	—	36	—
Corporate debt securities	144	—	144	—
Equity securities	434	434	—	—
Foreign government fixed income securities	7	1	6	—
Other trust fund investments (classified within other non-current assets):				
U.S. government and federal agency obligations	1	1	—	—
Derivative assets:				
Commodity contracts	821	59	623	139
Measured using net asset value practical expedient:				
Equity securities — nuclear trust fund investments	87			
Equity securities (classified within other non-current assets)	8			
Total assets	$ 1,745	$ 597	$ 914	$ 139
Derivative liabilities:				
Commodity contracts	$ 884	$ 86	$ 643	$ 155
Total liabilities	$ 884	$ 86	$ 643	$ 155

The following table reconciles, for the three and nine months ended September 30, 2021 and 2020, the beginning and ending balances for financial instruments that are recognized at fair value in the condensed consolidated financial statements, using significant unobservable inputs:

	Fair Value Measurement Using Significant Unobservable Inputs (Level 3)	
	Three months ended September 30, 2021	Nine months ended September 30, 2021
(In millions)	Derivatives[a]	Derivatives[a]
Beginning balance	$ 574	$ (16)
Contracts added from Direct Energy acquisition	—	(15)
Total (losses)/gains realized/unrealized— included in earnings	(175)	187
Purchases	—	78
Transfers into Level 3[b]	(108)	64
Transfers out of Level 3[b]	20	13
Ending balance	$ 311	$ 311
(Losses)/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 period end	$ (237)	$ 184

(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 September 30, 2020	Nine months ended September 30, 2020
(In millions)	Derivatives[a]	Derivatives[a]
Beginning balance	$ 152	$ 38
Total (losses) realized/unrealized — included in earnings	(92)	(18)
Purchases	(10)	6
Transfers into Level 3[b]	(11)	22
Transfers out of Level 3[b]	13	4
Ending balance	$ 52	$ 52
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 period end	$ 23	$ 50

(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. These contracts are valued based on various valuation techniques including, but not limited to, internal models based on a fundamental analysis of the market and extrapolation of the observable market data with similar characteristics. As of September 30, 2021, contracts valued with prices provided by models and other valuation techniques make up 5% of derivative assets and 3% of derivative liabilities.

NRG's significant positions classified as Level 3 include physical and financial natural gas and power contracts executed in illiquid markets, as well as FTRs. The significant unobservable inputs used in developing fair value include illiquid natural gas and 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 September 30, 2021 and December 31, 2020:

	September 30, 2021						
	Fair Value				Input/Range		
(In millions)	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
Natural Gas Contracts	$ 19	$ 3	Discounted Cash Flow	Forward Market Price (per MMBtu)	$ 3	$ 49	$ 19
Power Contracts	512	218	Discounted Cash Flow	Forward Market Price (per MWh)	3	263	40
FTRs	32	31	Discounted Cash Flow	Auction Prices (per MWh)	(131)	755	—
	$ 563	$ 252					

	December 31, 2020						
	Fair Value				Input/Range		
(In millions)	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
Power Contracts	$ 111	$ 143	Discounted Cash Flow	Forward Market Price (per MWh)	$ 10	$ 105	$ 21
FTRs	28	12	Discounted Cash Flow	Auction Prices (per MWh)	(28)	43	0
	$ 139	$ 155					

The following table provides sensitivity of fair value measurements to increases/(decreases) in significant unobservable inputs as of September 30, 2021 and December 31, 2020:

Significant Unobservable Input	Position	Change In Input	Impact on Fair Value Measurement
Forward Market Price Natural Gas/Power	Buy	Increase/(Decrease)	Higher/(Lower)
Forward Market Price Natural Gas/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 September 30, 2021, the credit reserve resulted in a $7 million decrease primarily within cost of operations. As of December 31, 2020, the credit reserve resulted in a $2 million increase primarily within 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 2020 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, as well as retail customer credit risk through its retail load activities.

Counterparty Credit Risk

The Company's counterparty credit risk policies are disclosed in its 2020 Form 10-K. As of September 30, 2021, counterparty credit exposure, excluding credit exposure from RTOs, ISOs, registered commodity exchanges and certain long-term agreements, was $2.9 billion and NRG held collateral (cash and letters of credit) against those positions of $1.1 billion, resulting in a net exposure of $1.9 billion. NRG periodically receives collateral from counterparties in excess of their exposure. Collateral amounts shown include such excess while net exposure shown excludes excess collateral received. Approximately 59% of the Company's exposure before collateral is expected to roll off by the end of 2022. 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	49 %
Financial institutions	51
Total as of September 30, 2021	100 %

Category by Counterparty Credit Quality	Net Exposure [(a)(b)] (% of Total)
Investment grade	78 %
Non-investment grade/non-rated	22
Total as of September 30, 2021	100 %

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

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

The Company currently has no exposure to wholesale counterparties in excess of 10% of total net exposure discussed above as of September 30, 2021. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration.

During Winter Storm Uri, the Company experienced nonperformance by a counterparty in one of its bilateral financial hedging transactions, resulting in exposure of $403 million. The Company is pursuing all means available to enforce its rights under this transaction but, given the size of the exposure, cannot determine with certainty what the amount of its ultimate recovery will be. The full exposure was recorded as a provision for credit losses during the nine months ended September 30, 2021.

RTOs and ISOs

The Company participates in the organized markets of CAISO, ERCOT, AESO, IESO, ISO-NE, MISO, NYISO and PJM, known as RTOs or ISOs. Trading in the majority of these markets is approved by FERC, whereas in the case of ERCOT, it is approved by the PUCT, and whereas in the case of AESO and IESO, both exist provincially with AESO primarily subject to Alberta Utilities Commission and the IESO to the Ontario Energy Board. These ISOs may include credit policies that, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. As a result, the counterparty credit risk to these markets is limited to NRG’s share of the overall market and are excluded from the above exposures.

Exchange Traded Transactions

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

Long-Term Contracts

Counterparty credit exposure described above excludes credit risk exposure under certain long-term contracts, primarily solar PPAs. As external sources or observable market quotes are not always available to estimate such exposure, the Company values these contracts based on various techniques including, but not limited to, internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Based on these valuation techniques, as of September 30, 2021, aggregate credit risk exposure managed by NRG to these counterparties was approximately $1.4 billion for the next five years.

Retail Customer Credit Risk

The Company is exposed to retail credit risk through the Company's retail electricity and gas providers, which serve Home and Business customers. Retail credit risk results in losses when a customer fails to pay for services rendered. The losses may result from both non-payment 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 September 30, 2021, the Company's retail customer credit exposure to Home and Business customers was diversified across many customers and various industries, as well as government entities. As a result of Winter Storm Uri, the Company incurred additional credit losses from Business customers primarily due to a segment of customers whose contracts included a pass through of wholesale power prices which were significantly escalated during the storm and from customers who failed to meet their obligations in ERCOT load curtailment programs.

Note 6 — Nuclear Decommissioning Trust Fund

NRG's Nuclear Decommissioning Trust Fund assets, which are for the decommissioning of its 44% interest in STP, 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 for the securities held in the trust funds, as well as information about the contractual maturities of those securities.

	As of September 30, 2021				As of December 31, 2020			
(In millions, except maturities)	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	$ 29	$ —	$ —	—	$ 23	$ —	$ —	—
U.S. government and federal agency obligations	76	4	—	12	70	6	—	10
Federal agency mortgage-backed securities	93	3	—	24	89	4	—	24
Commercial mortgage-backed securities	43	1	—	27	36	2	—	27
Corporate debt securities	116	8	1	14	144	13	—	12
Equity securities	596	439	—	—	521	372	—	—
Foreign government fixed income securities	4	—	—	12	7	1	—	10
Total	$ 957	$ 455	$ 1		$ 890	$ 398	$ —	

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

	Nine months ended September 30,	
(In millions)	2021	2020
Realized gains	$ 10	$ 22
Realized losses	(6)	(11)
Proceeds from sale of securities	424	318

Note 7 — Accounting for Derivative Instruments and Hedging Activities

Energy-Related Commodities

As of September 30, 2021, NRG had energy-related derivative instruments extending through 2036. The Company marks these derivatives to market through the statement of operations. NRG has executed power purchase agreements extending through 2038 that qualified for the NPNS exception and were therefore exempt from fair value accounting treatment.

Foreign Exchange Contracts

NRG is exposed to changes in foreign currency associated with the purchase of USD denominated natural gas for its Canadian business. In order to manage the Company's foreign exchange risk, NRG entered into foreign exchange contracts. As of September 30, 2021, NRG had foreign exchange contracts extending through 2024. The Company marks these derivatives to market through the statement of operations.

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 September 30, 2021 and December 31, 2020. 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 (In millions)	
Category	**Units**	**September 30, 2021**	**December 31, 2020**
Emissions	Short Ton	1	1
Renewable Energy Certificates	Certificates	13	5
Coal	Short Ton	3	2
Natural Gas	MMBtu	663	(286)
Oil	Barrels	1	—
Power	MWh	185	57
Capacity	MW/Day	—	(1)
Foreign Exchange	Dollars	$ 218	$ —

The increase in positions was primarily the result of the Direct Energy acquisition.

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	
(In millions)	**September 30, 2021**	**December 31, 2020**	**September 30, 2021**	**December 31, 2020**
Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Foreign exchange contracts - current	$ 1	$ —	$ —	$ —
Commodity contracts - current	8,527	560	6,032	499
Commodity contracts - long-term	2,671	261	1,489	385
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	$ 11,199	$ 821	$ 7,521	$ 884

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			
(In millions)	**Gross Amounts of Recognized Assets / Liabilities**	**Derivative Instruments**	**Cash Collateral (Held) / Posted**	**Net Amount**
As of September 30, 2021				
Foreign exchange contracts:				
Derivative assets	$ 1	$ —	$ —	$ 1
Total foreign exchange contracts	$ 1	$ —	$ —	$ 1
Commodity contracts:				
Derivative assets	$ 11,198	$ (6,946)	$ (1,712)	$ 2,540
Derivative liabilities	(7,521)	6,946	—	(575)
Total commodity contracts	$ 3,677	$ —	$ (1,712)	$ 1,965
Total derivative instruments	$ 3,678	$ —	$ (1,712)	$ 1,966

(In millions)	Gross Amounts Not Offset in the Statement of Financial Position: Gross Amounts of Recognized Assets / Liabilities	Derivative Instruments	Cash Collateral (Held) / Posted	Net Amount
As of December 31, 2020				
Commodity contracts:				
Derivative assets	$ 821	$ (658)	$ (5)	$ 158
Derivative liabilities	(884)	658	—	(226)
Total commodity contracts	$ (63)	$ —	$ (5)	$ (68)

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 and fair value hedges are reflected in current period results of operations.

The following table summarizes the pre-tax effects of economic hedges that have not been designated as cash flow hedges or fair value hedges and trading activity on the Company's statement of operations. The effect of foreign exchange and commodity hedges are included within operating revenues and cost of operations.

(In millions)	Three months ended September 30,		Nine months ended September 30,	
Unrealized mark-to-market results	2021	2020	2021	2020
Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges	$ (97)	$ (101)	$ (58)	$ (62)
Reversal of acquired (gain)/loss positions related to economic hedges	(42)	(2)	206	2
Net unrealized gains/(losses) on open positions related to economic hedges	1,924	(15)	3,875	73
Total unrealized mark-to-market gains/(losses) for economic hedging activities	1,785	(118)	4,023	13
Reversal of previously recognized unrealized (gains) on settled positions related to trading activity	(6)	(7)	(16)	(14)
Net unrealized gains on open positions related to trading activity	14	2	18	19
Total unrealized mark-to-market gains/(losses) for trading activity	8	(5)	2	5
Total unrealized gains/(losses)	$ 1,793	$ (123)	$ 4,025	$ 18

(In millions)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Unrealized gains/(losses) included in operating revenues - commodities	$ 11	$ 34	$ (97)	$ 83
Unrealized gains/(losses) included in cost of operations - commodities	1,777	(157)	4,121	(65)
Unrealized gains included in cost of operations - foreign exchange	5	—	1	—
Total impact to statement of operations	$ 1,793	$ (123)	$ 4,025	$ 18

The reversals of acquired 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 nine months ended September 30, 2021, the $3.9 billion unrealized gain from open economic hedge positions was primarily the result of an increase in value of forward positions as a result of increases in natural gas and power prices.

For the nine months ended September 30, 2020, the $73 million unrealized gain from open economic hedge positions was primarily the result of an increase in value of forward positions as a result of decreases in New York capacity and power prices, as well as increases in ERCOT power prices.

Credit Risk Related Contingent Features

Certain of the Company's hedging and trading agreements contain provisions that entitle the counterparty to demand that the Company post additional collateral if the counterparty determines that there has been deterioration in the Company's credit quality, generally termed "adequate assurance" under the agreements, or require the Company to post additional collateral if there were a downgrade in the Company's credit rating. In addition, as a result of the acquisition of Direct Energy from Centrica, certain of the Company's agreements as of September 30, 2021, were still supported by credit support posted by Centrica, and as a result could require the Company to post collateral upon a deterioration or downgrade of Centrica. The collateral potentially required for all contracts with adequate assurance clauses that are in a net liability position as of September 30, 2021 was $865 million. The Company is also party to certain marginable agreements under which it has net liability position, but the counterparty has not called for the collateral due, which was $92 million as of September 30, 2021. In the event of a downgrade in the Company's credit rating and if called for by the counterparty, $35 million of additional collateral would be required for all contracts with credit rating contingent features as of September 30, 2021.

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

Note 8 — Impairments

2021 Impairment Losses

PJM Asset Impairments — During the second quarter of 2021, the results of the PJM Base Residual Auction for the 2022/2023 delivery year were released leading the Company to announce the near-term retirement of a significant portion of its PJM coal generating assets in June 2022. The Company considered the decline in PJM capacity prices and the near-term retirement dates of certain assets to be a trigger for impairment and performed impairment tests on the PJM generating assets and the goodwill associated with Midwest Generation. The Company measured the impairment losses on the PJM generation assets and Midwest Generation goodwill as the difference between the carrying amount and the fair value of the PJM generating assets and Midwest Generation reporting unit, respectively. Fair values were determined using an income approach in which the Company applied a discounted cash flow methodology to the long-term budgets for the plants and reporting unit. Significant inputs impacting the income approach include the Company's long-term view of capacity and fuel prices, projected generation, the physical and economic characteristics of each plant, and the discount rate applied to the after-tax cash flow projections. Impairment losses of $271 million and $35 million were recorded in the East segment on the PJM generating assets and Midwest Generation goodwill, respectively.

2020 Impairment Losses

Home Solar — During the third quarter of 2020, the Company concluded its Home Solar business was held for sale as a result of advanced negotiations to sell the business. NRG recorded impairment losses of $29 million in the West/Other segment to adjust the carrying amount of the assets and liabilities to fair market value based on indicative sale prices.

Petra Nova Parish Holdings — During the first quarter of 2020, due to the decline in oil prices, NRG determined that the carrying amount of the Company's equity method investment exceeded the fair value of the investment and that the decline was considered to be other-than-temporary. In determining the fair value, the Company utilized an income approach to estimate future project cash flows. The Company recorded an impairment loss of $18 million in the Texas segment, which included the anticipated drawdown of the $12 million letter of credit posted in September 2019 to cover certain project debt reserve requirements.

Note 9 — Long-term Debt and Finance Leases

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

(In millions, except rates)	September 30, 2021	December 31, 2020	Interest rate %
Recourse debt:			
Senior Notes, due 2026	$ —	$ 1,000	7.250
Senior Notes, due 2027	875	1,230	6.625
Senior Notes, due 2028	821	821	5.750
Senior Notes, due 2029	733	733	5.250
Senior Notes, due 2029	500	500	3.375
Senior Notes, due 2031	1,030	1,030	3.625
Senior Notes, due 2032	1,100	—	3.875
Convertible Senior Notes, due 2048[(a)]	575	575	2.750
Senior Secured First Lien Notes, due 2024	600	600	3.750
Senior Secured First Lien Notes, due 2025	500	500	2.000
Senior Secured First Lien Notes, due 2027	900	900	2.450
Senior Secured First Lien Notes, due 2029	500	500	4.450
Tax-exempt bonds	466	466	1.250 - 4.750
Subtotal recourse debt	8,600	8,855	
Finance leases	13	4	various
Subtotal long-term debt and finance leases (including current maturities)	8,613	8,859	
Less current maturities	(504)	(1)	
Less debt issuance costs	(89)	(93)	
Discounts	(63)	(74)	
Total long-term debt and finance leases	$ 7,957	$ 8,691	

(a) As of the ex-dividend date of October 29, 2021, the Convertible Senior Notes were convertible at a price of $44.89, which is equivalent to a conversion rate of approximately 22.2761 shares of common stock per $1,000 principal amount

Recourse Debt

Issuance of 2032 Senior Notes

On August 23, 2021, the Company issued $1.1 billion of aggregate principal amount at par of 3.875% senior notes due 2032 (the "2032 Senior Notes"). The 2032 Senior Notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. Interest is paid semi-annually beginning on February 15, 2022 until the maturity date of February 15, 2032. The 2032 Senior Notes were issued under NRG's Sustainability-Linked Bond Framework, which sets out certain sustainability targets, including reducing greenhouse gas emissions. Failure to meet such sustainability targets will result in a 25 basis point increase to the interest rate payable on the 2032 Senior Notes from and including August 15, 2026. The proceeds of the 2032 Senior Notes, along with cash on hand, were used to fund the redemption of $1.0 billion 7.250% Senior Notes due 2026 and $355 million of 6.625% Senior Notes due 2027.

2021 Senior Note Redemptions

On August 24, 2021, the Company redeemed $1.4 billion in aggregate principal of its Senior Notes for $1.4 billion using the proceeds of the 2032 Senior Notes and cash on hand. In connection with the redemptions, a $57 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $9 million, during the nine months ended September 30, 2021. The Company redeemed an additional $500 million of its 6.625% Senior Notes due 2027 in October 2021.

(In millions, except percentages)	Principal Repurchased	Cash Paid[a]	Average Early Redemption Percentage
7.250% Senior Notes, due 2026	$ 1,000	$ 1,056	103.625 %
6.625% Senior Notes, due 2027	355	369	103.313 %
Total Redemptions during the nine months ended September 30, 2021	$ 1,355	$ 1,425	
6.625% Senior Notes, due 2027	$ 500	$ 524	103.313 %
Total Redemptions January 1, 2021 through November 4, 2021	$ 1,855	$ 1,949	

(a) Includes accrued interest of $22 million and $29 million for redemptions through September 30, 2021 and November 4, 2021, respectively

Receivables Securitization Facilities

On July 26, 2021, NRG Receivables LLC, a wholly-owned indirect subsidiary of the Company, entered into the First Amendment to its accounts receivable securitized borrowing facility dated September 22, 2020 with a group of conduit lenders and banks and Royal Bank of Canada, as Administrative Agent (as amended, the "Receivables Facility") to, among other things, (i) increase the existing revolving commitments by $50 million to an aggregate amount of $800 million, (ii) extend the maturity date until July 26, 2022, (iii) make certain adjustments to the pool of receivables through the Receivables Facility and certain related covenants and (iv) provide for revised language relating to interest determination based on SOFR in case of a LIBOR cessation or the occurrence of certain other trigger events. As of September 30, 2021, there were no outstanding borrowings and there were $400 million in letters of credit issued under the Receivables Facility.

On July 26, 2021, the Company renewed its existing Repurchase Facility to, among other things, (i) extend the maturity date to July 26, 2022 and (ii) provide for revised language relating to interest determination based on SOFR in case of a LIBOR cessation or the occurrence of certain other trigger events.

Revolving Credit Facility

During the third quarter of 2020, the Company amended its existing credit agreement to, among other things, (i) increase the existing revolving commitments in an aggregate amount of $802 million, and (ii) provide for a new tranche of revolving commitments in an aggregate amount of $273 million with a maturity date of July 5, 2023. The maturity date of the new revolving tranche of commitments may, upon request by the Company, and at the option of each applicable lender under the new tranche be extended to May 28, 2024, which is the maturity date of the existing and increased commitments. Other than with respect to the maturity date, the terms of all revolving commitments and loans made pursuant thereto are identical. The increase in the existing commitments, and the commitments with respect to the new tranche were effective on August 20, 2020 and became available on January 5, 2021 upon the closing of the Direct Energy Acquisition. As of September 30, 2021, total revolving commitments available, subject to usage, under the amended credit agreement was $3.7 billion.

Non-Recourse Debt

Put Option Agreement for Senior Debt Issuance

As further discussed in Part IV, Item 15, Note 14, *Long-term Debt and Finance Leases* of the Company's 2020 Form 10-K, the Company entered into a Put Option Agreement for Senior Debt Issuances (the "P-Caps"). In connection with the issuance of the P-Caps, on December 11, 2020, NRG entered into an amended and restated facility agreement for the issuance of letters of credit (the "LC Agreement") with Deutsche Bank Trust Company Americas as collateral agent (the "Collateral Agent") and administrative agent pursuant to which certain financial institutions (the "LC Issuers") have agreed to provide letters of credit in an aggregate amount not to exceed $874 million to support the operations of NRG and its subsidiaries and minority investments, including to replace certain letters of credit and other credit support issued for the account of entities acquired pursuant to the Direct Energy Acquisition. In addition, on December 11, 2020, the Trust entered into an amended and restated pledge and control agreement (the "Pledge Agreement"), among NRG, the Trust and the Collateral Agent for the LC Issuers, under which the Trust agreed to grant a pledge over the Eligible Treasury Assets in favor of the Collateral Agent for the benefit of the LC Issuers. Pursuant to the LC Agreement and the Pledge Agreement, the Collateral Agent is entitled to withdraw Eligible Treasury Assets from the Trust's pledged account, following notice to NRG, in the event NRG has failed to reimburse amounts drawn under any letter of credit issued pursuant to the LC Agreement, and the LC Issuers have the right to instruct the

Collateral Agent to enforce the pledge over the Eligible Treasury Assets upon the occurrence of any event of default under the LC Agreement. The LC Agreement and the Pledge Agreement were available on January 5, 2021. As of September 30, 2021, $864 million of letters of credit were issued under the LC Agreement.

Note 10 — Investments Accounted for Using the Equity Method and Variable Interest Entities, or VIEs

Entities that are not Consolidated

NRG accounts for the Company's significant investments using the equity method of accounting. NRG's carrying value of equity investments can be impacted by a number of elements including impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates. On February 3, 2021, the Company sold its 35% ownership in Agua Caliente to Clearway Energy, Inc. for $202 million as further described in Note 4, *Acquisitions and Dispositions.*

Variable Interest Entities that are Consolidated

The Company has a controlling financial interest that has been identified as a VIE under ASC 810 in NRG Receivables LLC, which has entered into financing transactions related to the Receivables Facility as further described in Note 13, *Receivables Securitization and Repurchase Facility,* to the Company's 2020 Form 10-K.

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

(In millions)	September 30, 2021	December 31, 2020
Accounts receivable	$ 730	$ 647
Other current assets	—	2
Total assets	730	649
Current liabilities	78	78
Net assets	$ 652	$ 571

Note 11 — Changes in Capital Structure

As of September 30, 2021 and December 31, 2020, 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, 2020	423,057,848	(178,825,915)	244,231,933
Shares issued under LTIPs	487,413	—	487,413
Shares issued under ESPP	—	59,967	59,967
Balance as of September 30, 2021	423,545,261	(178,765,948)	244,779,313
Shares issued under LTIPs	1,913	—	1,913
Shares issued under ESPP	—	57,425	57,425
Balance as of November 4, 2021	423,547,174	(178,708,523)	244,838,651

Employee Stock Purchase Plan

In March 2019, the Company reopened participation in the ESPP, which allows eligible employees to elect to withhold between 1% and 10% of their eligible compensation to purchase shares of NRG common stock at the lesser of 95% of its market value on the offering date or 95% of the fair market value on the exercise date. An offering date occurs each April 1 and October 1. An exercise date occurs each September 30 and March 31.

NRG Common Stock Dividends

During the first quarter of 2021, NRG increased the annual dividend to $1.30 from $1.20 per share and expects to target an annual dividend growth rate of 7-9% per share in subsequent years. A quarterly dividend of $0.325 per share was paid on the Company's common stock during the three months ended September 30, 2021. On October 15, 2021, NRG declared a quarterly dividend on the Company's common stock of $0.325 per share, payable on November 15, 2021 to stockholders of record as of November 1, 2021. Beginning in the first quarter of 2022, NRG will increase the annual dividend by 8% to $1.40 per share.

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

Note 12 — Income Per Share

Basic income per common share is computed by dividing net income by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted income per share is computed in a manner consistent with that of basic income per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The outstanding relative performance stock units, non-vested restricted stock units, market stock units, and non-qualified stock options are not considered outstanding for purposes of computing basic income per share. However, these instruments are included in the denominator for purposes of computing diluted income per share under the treasury stock method. The Convertible Senior Notes are convertible, under certain circumstances, into the Company's common stock, cash or combination thereof (at NRG's option). There is no dilutive effect for the Convertible Senior Notes due to the Company's expectation to settle the liability in cash.

The reconciliation of NRG's basic and diluted income per share is shown in the following table:

	Three months ended September 30,		Nine months ended September 30,	
(In millions, except per share data)	**2021**	**2020**	**2021**	**2020**
Basic income per share:				
Net income	$ 1,618	$ 249	$ 2,614	$ 683
Weighted average number of common shares outstanding - basic	245	244	245	246
Income per weighted average common share — basic	$ 6.60	$ 1.02	$ 10.67	$ 2.78
Diluted income per share:				
Net income	$ 1,618	$ 249	$ 2,614	$ 683
Weighted average number of common shares outstanding - basic	245	244	245	246
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	—	1	—	1
Weighted average number of common shares outstanding - dilutive	245	245	245	247
Income per weighted average common share — diluted	$ 6.60	$ 1.02	$ 10.67	$ 2.77

As of September 30, 2021 and 2020 the Company had an insignificant number of outstanding equity instruments that are anti-dilutive and were not included in the computation of the Company's diluted income per share.

Note 13 — Segment Reporting

The Company's segment structure reflects how management currently makes financial decisions and allocates resources. The Company manages its operations based on the combined results of the retail and wholesale generation businesses with a geographical focus.

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 allocation of capital, as well as net income/(loss).

The acquired operations of Direct Energy are integrated into the existing NRG segment structure. Domestic customer and market operations are combined into the corresponding geographical segments of Texas, East and West/Services/Other. The West/Services/Other segment includes activity related to the Canadian operations as well as the services businesses.

	Three months ended September 30, 2021					
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate**	**Eliminations**	**Total**
Operating revenues	$ 2,635	$ 3,077	$ 884	$ —	$ 13	$ 6,609
Depreciation and amortization	84	88	20	7	—	199
Equity in earnings of unconsolidated affiliates	(2)	—	17	—	—	15
Income/(loss) before income taxes	251	1,989	131	(208)	—	2,163
Net income/(loss)	**$ 251**	**$ 1,976**	**$ 130**	**$ (739)**	**$ —**	**$ 1,618**
Total assets as of September 30, 2021	**$ 9,929**	**$ 19,940**	**$ 4,655**	**$ 10,507**	**$ (17,066)**	**$ 27,965**

	Three months ended September 30, 2020					
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate**	**Eliminations**	**Total**
Operating revenues	$ 1,992	$ 666	$ 149	$ —	$ 2	$ 2,809
Depreciation and amortization	49	33	10	7	—	99
Impairment losses	—	—	29	—	—	29
Equity in losses of unconsolidated affiliates	—	—	36	—	—	36
Income/(loss) before income taxes	287	146	23	(115)	—	341
Net income/(loss)	**$ 287**	**$ 145**	**$ 23**	**$ (206)**	**$ —**	**$ 249**

	Nine months ended September 30, 2021					
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate**	**Eliminations**	**Total**
Operating revenues	$ 8,362	$ 9,002	$ 2,564	$ —	$ 15	$ 19,943
Depreciation and amortization	245	238	65	21	—	569
Impairment losses	—	306	—	—	—	306
Gain on sale of assets	—	—	17	—	—	17
Equity in (losses)/earnings of unconsolidated affiliates	(3)	—	26	—	—	23
Income/(loss) before income taxes	600	3,136	254	(536)	—	3,454
Net income/(loss)	**$ 600**	**$ 3,107**	**$ 251**	**$ (1,344)**	**$ —**	**$ 2,614**

	Nine months ended September 30, 2020					
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate**	**Eliminations**	**Total**
Operating revenues	$ 4,928	$ 1,732	$ 407	$ —	$ (1)	$ 7,066
Depreciation and amortization	167	97	28	26	—	318
Impairment losses	—	—	29	—	—	29
Gain on sale of assets	—	—	1	5	—	6
Equity in (losses)/earnings of unconsolidated affiliates	(3)	—	40	—	—	37
Income/(loss) before income taxes	799	308	98	(306)	—	899
Net income/(loss)	**$ 799**	**$ 307**	**$ 97**	**$ (520)**	**$ —**	**$ 683**

Note 14 — Income Taxes

Effective Income Tax Rate

The income tax provision consisted of the following:

(In millions, except rates)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Income before income taxes	$ 2,163	$ 341	$ 3,454	$ 899
Income tax expense	545	92	840	216
Effective income tax rate	25.2 %	27.0 %	24.3 %	24.0 %

For the three months ended September 30, 2021, the effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense. For the nine months ended September 30, 2021, the effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense partially offset by one-time tax benefits, as a result of the acquisition of Direct Energy, on the revaluation of state deferred tax assets, NOLs and valuation allowance. For the same periods in 2020, the effective tax rates were higher than the statutory rate of 21% due to state tax expense partially offset by an excess tax benefit related to share-based compensation.

Uncertain Tax Benefits

As of September 30, 2021, NRG had a non-current tax liability of $25 million for uncertain tax benefits from positions taken on various federal and state income tax returns and accrued interest. For the nine months ended September 30, 2021, NRG accrued an immaterial amount of interest relating to the uncertain tax benefits. As of September 30, 2021, NRG had cumulative interest and penalties related to these uncertain tax benefits of $3 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 and Canada. The Company is no longer subject to U.S. federal income tax examinations for years prior to 2017. With few exceptions, state and local income tax examinations are no longer open for years prior to 2012.

Note 15 — Related Party Transactions

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

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

(In millions)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Revenues from Related Parties Included in Operating Revenues				
Gladstone	$ 1	$ 1	$ 2	$ 2
Ivanpah[(a)]	9	11	30	34
Midway-Sunset	1	1	4	4
Total	$ 11	$ 13	$ 36	$ 40

(a) Also includes fees under project management agreements with each project company

Note 16 — Commitments and Contingencies

Commitments

The Company disclosed its commitments in Note 24, *Commitments and Contingencies*, to the Company's 2020 Form 10-K. NRG completed the acquisition of Direct Energy on January 5, 2021 and assumed additional purchased energy commitments as detailed below.

Purchased Energy Commitments

NRG assumed additional long-term contractual commitments related to electricity and natural gas products, including power purchases, gas transportation and storage. The Company's minimum commitments under such outstanding agreements as of the Acquisition Closing Date are estimated as follows:

	(In millions)
2021	$ 246
2022	396
2023	272
2024	180
2025	134
Thereafter	450
Total	$ 1,678

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of property and assets owned by NRG and the guarantors of its senior debt. NRG uses the first lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedges. To the extent that the underlying hedge positions for a counterparty are out-of-the-money to NRG, the counterparty may have a claim under the first lien program. As of September 30, 2021, all hedges under the first lien program were out-of-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 accruals for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. As applicable, the Company has established an adequate accrual for the applicable legal matters, including regulatory and environmental matters as further discussed in Note 17, *Regulatory Matters*, and Note 18, *Environmental Matters*. In addition, legal costs are expensed as incurred. Management has assessed each of the following matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, the Company is unable to predict the outcome of these legal proceedings or reasonably estimate the scope or amount of any associated costs and potential liabilities. As additional information becomes available, management adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of the Company's liabilities and contingencies could be at amounts that are different from their currently recorded accruals and that such differences 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.

Environmental Lawsuits

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

Consumer Lawsuits

Similar to other energy service companies ("ESCOs") operating in the industry, from time-to-time, the Company and/or its subsidiaries may be subject to consumer lawsuits in various jurisdictions where they sell natural gas and electricity.

Variable Price Cases — In the cases set forth below, referred to as the Variable Price Cases, such actions involve consumers alleging that one of the Company's ESCOs promised that consumers would pay the same or less than they would have paid if they stayed with their default utility or previous energy supplier. The underlying claims of each case are similar and the Company continues to deny the allegations and is vigorously defending these matters. These matters were known and accrued for at the time of each acquisition.

<u>XOOM Energy</u>
XOOM Energy is a defendant in a putative class action lawsuit pending in New York. This case is in the discovery phase.

<u>Direct Energy</u>
There are four putative class actions pending against Direct Energy: (1) Linda Stanley v. Direct Energy (S.D.N.Y Apr. 2019) - The parties mediated in June and agreed on a settlement. Once the settlement is drafted and signed, it will be submitted to the Court for approval; (2) Martin Forte v. Direct Energy (N.D.N.Y. Mar. 2017) - Direct Energy's Motion for Summary Judgment and Plaintiff's Class Certification are fully briefed and awaiting a ruling; (3) Richard Schafer v. Direct Energy (W.D.N.Y. Dec. 2019; on appeal 2nd Cir. N.Y.) - The trial court dismissed this action. Plaintiff appealed to the Second Circuit Court of Appeals. Oral arguments took place in April 2021. Subsequently, the Second Circuit issued a summary opinion vacating the district court's dismissal of the case. The matter was remanded back to the district court for further action; and (4) Julie and Richard Lane v. Direct Energy (S.D.Ill. Jun. 2019) - Plaintiffs have amended their Complaint in response to the Court dismissing all claims except a claim under the Illinois Consumer Protection Act. Direct Energy's Motion to Dismiss was granted by the Court on April 26, 2021. The time to appeal this determination has passed.

Telephone Consumer Protection Act ("TCPA") Cases — In the cases set forth below, referred to as the TCPA Cases, such actions involve consumers alleging violations of the Telephone Consumer Protection Act of 1991, as amended, by receiving calls, texts or voicemails without consent in violation of the federal Telemarketing Sales Rule, and/or state counterpart legislation. The underlying claims of each case are similar. The Company denies the allegations asserted by plaintiffs and intends to vigorously defend these matters. These matters were known and accrued for at the time of the acquisition.

There are two putative class actions pending against Direct Energy: (1) Brittany Burk v. Direct Energy (S.D. Tex. Feb. 2019) - The briefing on Direct Energy's Motion to Dismiss and Plaintiff's Class Certification is complete. The Court denied Plaintiff's Motion for Class Certification and Motion for Substitution of a New Plaintiff on September 20, 2021. The parties have reached a settlement of the plaintiff's individual claims and expect the Court to dismiss the matter in the next 30 to 60 days; and (2) Matthew Dickson v. Direct Energy (N.D.Ohio Jan. 2018) - Direct Energy has filed a Third-Party Petition against its vendor, Total Marketing Concepts, LLC, who placed voicemails without consent from Direct Energy and in violation of the parties' agreement. The case was stayed pending the outcome of an appeal to the Sixth Circuit based on the unconstitutionality of the TCPA during the period from 2015-2020. The Sixth Circuit found the TCPA was in effect during that period and remanded the case back to the trial court. The stay has been lifted and the Company plans to refile its previous motions and start discovery.

Winter Storm Uri Lawsuits

The Company has been named in certain property damage and wrongful death claims that have been filed in connection with Winter Storm Uri. At this time, the Company is unable to determine the extent or impact of these various litigation matters due to their preliminary nature. The Company intends to vigorously defend these matters.

Indemnifications and Other Contractual Arrangements

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 LaGen in the United States District Court for the Middle District of Louisiana. The plaintiffs claimed 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 sought damages for the alleged improper charges and a declaration as to which charges were proper under the contract. In February 2020, the court dismissed this lawsuit without prejudice for lack of subject matter jurisdiction. On March 17, 2020, plaintiffs filed a lawsuit in the Nineteenth Judicial District Court for the Parish of East Baton Rouge in Louisiana alleging substantially the same matters. On February 4, 2019, NRG sold the South Central Portfolio, including the entities subject to this litigation. However, NRG has agreed to indemnify the purchaser for certain losses suffered in connection therewith.

Note 17 — Regulatory Matters

Environmental regulatory matters are discussed within Note 18, *Environmental Matters.*

NRG operates in a highly regulated industry and is subject to regulation by various federal, state and provincial agencies. As such, NRG is affected by regulatory developments at the federal, state and provincial 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 operations.

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

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

South Central — On August 4, 2016, NRG received a document hold notice from FERC regarding conduct in the MISO and PJM markets. FERC Office of Enforcement Staff investigated potential violations of MISO rules involving bidding for the Big Cajun 2 facility, as well as other aspects of NRG's operations in MISO. On August 18, 2020, FERC Office of Enforcement presented NRG with its preliminary findings. NRG responded to the preliminary findings on January 15, 2021. On September 16, 2021, FERC Office of Enforcement Staff informed NRG that the investigation is closed with no further action.

Note 18 — Environmental Matters

NRG is subject to a wide range of environmental laws in the development, construction, ownership and operation of power plants. These laws generally require that governmental permits and approvals be obtained before construction and maintained during operation of power plants. The electric generation industry has been facing increasingly stringent requirements regarding air quality, GHG emissions, combustion byproducts, water discharge and use, and threatened and endangered species. In general, future laws are expected to require the addition of emissions controls or other environmental controls or to impose additional 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. The Company has elected to use a $1 million disclosure threshold, as permitted, for environmental proceedings to which the government is a party.

Air

On July 8, 2019, the EPA promulgated the ACE rule, which rescinded the CPP, which had sought to broadly regulate CO_2 emissions from the power sector. The ACE rule required states that have coal-fired EGUs to develop plans to seek heat rate improvements from coal-fired EGUs. On January 19, 2021, the D.C. Circuit vacated the ACE rule (but on February 22, 2021, at the EPA's request, stayed the issuance of the portion of the mandate that would vacate the repeal of the CPP). On October 29, 2021, the U.S. Supreme Court agreed to review the D.C. Circuit's decision, which should provide some clarity regarding the scope of the EPA's authority to regulate CO_2 under the Clean Air Act. The Company expects the EPA to promulgate a new rule to regulate GHG emissions from power plants after a decision from the U.S. Supreme Court.

Water

Effluent Limitations Guidelines — In November 2015, the EPA revised the Effluent Limitations Guidelines ("ELG") for Steam Electric Generating Facilities, which imposed more stringent requirements (as individual permits were renewed) for wastewater streams from FGD, fly ash, bottom ash, and flue gas mercury control. On September 18, 2017, the EPA promulgated a final rule that, among other things, postponed 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 amended the rule. On October 13, 2020, the EPA amended the 2015 ELG rule by: (i) altering the stringency of certain limits for FGD wastewater; (ii) relaxing the zero-discharge requirement for bottom ash transport water; and (iii) changing several deadlines. On July 26, 2021, the EPA announced that it is initiating a new rulemaking to evaluate revising the ELG rule. While the EPA is developing the new rule, the existing rule (as amended in 2020) will stay in place, and the EPA expects permitting authorities to continue to implement the current regulation. The EPA anticipates releasing a proposed rule in fall 2022. In October 2021, NRG informed its regulators that the Company intends to comply with the ELG by ceasing combustion of coal by the end of 2028 at its domestic coal units outside of Texas, and installing appropriate controls by the end of 2025 at its two plants in Texas.

Byproducts, Wastes, Hazardous Materials and Contamination

In April 2015, the EPA finalized the rule regulating byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. In September 2017, the EPA agreed to reconsider the rule. On July 30, 2018, the EPA promulgated a rule that amended the 2015 ash rule by extending some of the deadlines and providing more flexibility for compliance. On August 21, 2018, the D.C. Circuit found, among other things, that the EPA had not adequately regulated unlined ponds and legacy ponds. In 2019 and 2020, the EPA proposed several changes to this rule. On August 28, 2020, the EPA finalized "A Holistic Approach to Close Part A: Deadline to Initiate Closure," which amended the April 2015 Rule to address the August 2018 D.C. Circuit decision and extend some of the deadlines. On November 12, 2020, the EPA finalized "A Holistic Approach to Closure Part B," which further amended the April 2015 Rule to, among other things, provide procedures for requesting approval to operate existing impoundments with an alternative liner. The Company has updated its estimates of required environmental capital expenditures.

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

The discussion and analysis below has been organized as follows:

- Executive summary, including 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.

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 nine months ended September 30, 2021 and 2020. Also refer to NRG's 2020 Form 10-K, which includes detailed discussions of various items impacting the Company's business, results of operations and financial condition, including: General section; Strategy section; Business Overview section, including how regulation, weather, and other factors affect NRG's business; and Critical Accounting Policies and Estimates section.

Executive Summary

Introduction and Overview

NRG is a consumer services company built on dynamic retail brands with diverse generation assets. NRG brings the power of energy to customers by producing and selling energy and related products and services, nation-wide in the U.S. and Canada in a manner that delivers value to all of NRG's stakeholders. The Company sells energy, services, and innovative, sustainable solutions and advisory services to approximately 6 million Home customers under the names NRG, Reliant, Direct Energy, Green Mountain Energy, Stream, and XOOM Energy, as well as other brand names owned by NRG, supported by approximately 23,000 MW of generation, including approximately 4,850 MW of fossil generation assets held for sale as of September 30, 2021 and approximately 1,600 MW of its PJM coal fleet with a retirement date of June 2022.

Strategy

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

To effectuate the Company's strategy, NRG is focused on: (i) serving the energy needs of end-use residential, commercial and industrial, and wholesale customers in competitive markets through multiple brands and channels; (ii) offering a variety of energy products and services, including renewable energy solutions, that are differentiated by innovative features, premium service, sustainability, and loyalty/affinity programs; (iii) excellence in operating performance of its existing assets; (iv) optimal hedging of NRG's portfolio; and (v) engaging in disciplined and transparent capital allocation.

The Company is implementing a four-year plan beginning in 2022 to invest $2 billion in order to achieve growth through optimization of the Company's core power and natural gas sales, as well as integrated solution sales within our core network in both power and home services.

Sustainability is an integral part of NRG's strategy and ties directly to business success, reduced risks and brand value. In 2019, NRG announced the acceleration of its science-based GHG emissions reduction goals to align with prevailing climate science, which seeks to limit global warming in the post-industrial era to 1.5 degrees Celsius. NRG is targeting a 50% reduction by 2025, from its current 2014 baseline, and net-zero emissions by 2050.

Energy Regulatory Matters

The Company's regulatory matters are described in the Company's 2020 Form 10-K in Item 1, Business — *Regulatory Matters.* These matters have been updated below and in Note 17, *Regulatory Matters.*

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

In March 2021, President Biden announced a framework for his "Build Back Better" initiative. The framework includes policies to address climate change across the whole of the federal government through the tax code, an energy efficiency and clean energy incentives, research and development, among other areas of focus. "Build Back Better" is currently on two tracks in Congress, with a bipartisan, $1.2 trillion "core infrastructure" bill that is awaiting a vote in the U.S. House of Representatives and a budget reconciliation bill to address additional priorities that is still being drafted by both Chambers. Both are expected to come to a vote by the end of the year, if not before. NRG is closely monitoring both legislative and executive agency action and expects to be an active participant as these legislative proposals are shaped and finalized.

On April 22, 2021, the President announced that the United States' Nationally Defined Contribution to the international Paris Climate Agreement will be an economy-wide reduction in greenhouse gas emissions of 50-52% by 2030, relative to 2005 levels. Further regulatory climate-related announcements are likely from the Biden Administration in the lead up to the Conference of the Parties 26 meeting being held in early November in Glasgow, Scotland.

State and Provincial Energy Regulation

Illinois Legislation — Illinois Governor J.B. Pritzker signed the Climate and Equitable Jobs Act (Public Act 102-0662) into law on September 15, 2021, which targets 100% clean energy by 2050. Three key provisions of the new law are decarbonization, incentives to transition coal plants into clean energy facilities and nuclear subsidies. The new law will require non-public coal or oil electric generating units larger than 25 MWs to permanently reduce all CO2e and copollutant emissions to zero no later than January 1, 2030. Non-public electric generating units that use gas as a fuel must permanently reduce all CO2e and copollutant emissions to zero, including through unit retirement or the use of 100% green hydrogen in a timeframe ranging from January 1, 2030 to January 1, 2045 depending on certain emission rates and proximity to an environmental justice community. The new energy law also provides $173 million in incentives to develop solar and battery storage at coal generating sites that may be available to NRG.

Regional Regulatory Developments

NRG is affected by rule and tariff changes that occur in the ISO regions. For further discussion on regulatory developments see Note 17, *Regulatory Matters*.

Texas

Legislative Activity Post-Winter Storm Uri — The Texas Legislature has conducted committee hearings during its Special Sessions to continue to evaluate the design of the ERCOT wholesale market and the weatherization of sources of power and fuel supply and related infrastructure. The PUCT is engaged in extensive rulemaking proposals to implement legislation passed during the Regular Session, most notably in response to Senate Bill ("SB") 3, the comprehensive package of electric industry reforms passed in the wake of Winter Storm Uri.

Public Utility Commission of Texas' Actions with Respect to Wholesale Pricing and Market Design — In September 2021, the PUCT opened a rulemaking project to evaluate whether it should amend its rules to adjust the High System Wide Offer cap ("HCAP") from $9,000 MWh to $4,500 MWh. Several stakeholders have filed comments advocating that any adjustment to the HCAP should be implemented in connection with reforms to the Operating Reserves Demand Curve ("ORDC") to ensure prices in the competitive market appropriately reflect the value of operating reserves. This rulemaking project is currently pending, with an expected resolution either at the end of 2021 or early 2022.

In accordance with SB3, Chairman Lake, has announced that he intends to release a "blueprint" for ERCOT market design reforms this fall. Stakeholders filed proposed market-design revisions on September 30, 2021. Proposals include extensions of the ORDC, the introduction of new reserves products for dispatchable capacity and winter fuel, and the institution of a load-serving entity reliability obligation that would require forward bilateral contracting during seasons of projected resource inadequacy.

Activity on Securitization and ERCOT Pricing during Winter Storm Uri — The Texas Legislature acted to pass a variety of securitization vehicles, including House Bill ("HB") 4492, to finance exceptionally high power and gas costs from Winter Storm Uri. HB4492 provides for approximately $800 million in financing to cover short payments resulting from defaults and up to $2.1 billion for highly priced ancillary service and operating reserve deployment adders ("ORDPA") during the event.

On July 16, 2021, ERCOT filed two applications requesting the PUCT to issue Debt Obligation Orders (DOOs") in relation to these two categories of cost in Docket No. 52321 and 52322. On September 20, 2021, an unopposed partial settlement was filed in Docket No. 52322, related to ERCOT's application for the $2.1 billion in ancillary service and ORDPA charges. On October 13, 2021, the PUCT issued an Order adopting the settlement's methodology for allocation of proceeds based on a load serving entity's ("LSEs") exposure to relevant costs as calculated by the LSE's prevailing load-ratio share during the period of Winter Storm Uri, and a further redistribution of proceeds initially allocated to other LSEs and customers who opt-out of securitization. The PUCT also issued an Order on October 13, 2021 to approve ERCOT's application for financing of $800 million in default costs under Docket No. 52321.

Under the DOOs, loans or securitized bonds would be issued by ERCOT through a bankruptcy remote special purpose entity as the borrower. The proceeds of these borrowings then would be paid to affected market participants for default-related short payments and to load-serving entities for certain ancillary-servicing and ORDPA costs. In turn, ERCOT would charge non-bypassable fees to all qualified scheduling entities and to all load-serving entities. With respect to ancillary services and ORDPA securitization, HB4492 does provide for a one-time opt-out for certain load-serving entities or individual transmission-level customers who in exchange for foregoing any securitization-related proceeds likewise avoid future fees assessed by ERCOT for the use of repaying ERCOT's debt obligations. However, nearly all competitive REPs are required by the law to participate, ensuring the charge established by the law is competitively neutral.

All opt-outs must be filed no later than 45 days following the Commission's October 13, 2021 order. Approximately 55 days after the Commission's order, ERCOT will file with the PUCT a calculation of LSEs' share of proceeds based on the settlement methodology, and LSEs will have 70 days from the date of the Commission's order to validate or challenge this calculation. The opt-outs and calculations noted above will be processed in the PUCT's parallel securitization proceeding, Docket No. 52364. NRG will be obligated to refund or provide invoice adjustments for a portion of whatever it receives to customers to whom relevant costs are passed-through.

With respect to Docket No. 52321, the $800 million proceeds will pay those short-paid market participants and reimburse congestion revenue rights account holders for amounts related to the default of market participants other than electric co-operatives Brazos Electric Power Cooperative, Inc. ("Brazos") and Rayburn Country Electric Cooperative, Inc. ("Rayburn"), which are dealt with separately and discussed below. ERCOT's market protocols provide for short payments to be extinguished through a process of uplift, whereby the cost of defaults is allocated to all market participants, including retailers, generators, municipal and co-operative utilities, and financial traders. However, the total amount of this uplift is limited by ERCOT's current protocols to $2.5 million per month. Consequently, it would take approximately 99 years for the current net short-pay balance to be uplifted to the market under the current market rules. NRG's undiscounted share of the uplift based on its current market share is estimated to be approximately $189 million and has been short-paid $83 million. The remaining $106 million has been discounted based on the 99 year repayment term and present value of $12 million was recorded as an additional liability. Taken together, HB4492 and SB1580, discussed below, provide an avenue for the complete resolution of market participant defaults and resulting short payments in ERCOT resulting from Winter Storm Uri.

Electric Co-operative Bankruptcy and Securitization — SB1580 provides for and purports to require electric co-operatives with large unpaid balances to ERCOT to securitize those debts and promptly repay ERCOT. If they do not, the law would require the PUCT to order ERCOT to suspend their participation in the wholesale market. To date, the PUCT as not taken an action in this regard.

Of the defaults in the ERCOT market, two electric co-operatives, Brazos and Rayburn, constitute the vast majority. Brazos currently is in bankruptcy. On June 14, 2021, NRG filed a proof of claim in the bankruptcy proceeding of Brazos. On August 18, 2021, Brazos initiated an adversary proceeding challenging ERCOT's claim. To the extent the Bankruptcy Court reduces or disallows ERCOT's claims against Brazos, this could impose a risk on NRG with respect to its claims. Therefore, on September 17, 2021, NRG and similarly situated parties filed a motion in the adversary proceeding. The Bankruptcy Court conducted a hearing on NRG's proposed intervention on October 18, 2021. Trial in the adversary proceeding is currently scheduled for February 21, 2022.

Meanwhile, Rayburn announced in the context of PUCT Docket No. 52322 that it intended to securitize the amounts owed to ERCOT, and as part of the PUCT order in that proceeding, was acknowledged to have opted out of the HB4492 securitization related to ancillary services an ORDPA costs, in view of its intentions to securitize the much larger amount that it continues to owe ERCOT.

Reliability and Plant Operations Standards — The PUCT established Project 51840, a rulemaking to establish weatherization standards, and issued a notice for comments in response to provisions of SB3 that require mandatory standards for power generators and others within the electric-power sector. SB3 provides that the standards adopted by the PUCT be implemented by generation owners, be subject to ERCOT inspections, and that ERCOT provide asset owners with a reasonable period of time to remedy any violation. Continuing violations would be subject to an administrative penalty and a requirement that a third-party contractor assess the asset owner's weatherization plans. On July 19, 2021, the PUCT filed draft weatherization standards for discussion purposes, and on July 30,2021, NRG filed comments in response to the draft standards. On August 24, 2021, Commission Staff issued a proposal for publication. NRG, through its trade association, filed comments. On October 21, 2021, Commissioners of the PUCT voted to adopt the rule without substantial modifications from the proposal.

Concurrently, FERC Staff and NERC issued preliminary findings of a report entitled *February 2021 Cold Weather Grid Operations* at the September 23, 2021 FERC open meeting. The agency announced it expects a final report by winter 2021-22. Preliminary recommendations include requiring generation owners subject to NERC reliability standards to meet certain weatherization standards for cold weather. It is not clear how such reliability standards will interact with state-level requirements, or when they would be promulgated through the NERC and FERC regulatory process.

PJM

PJM'S Variable Resource Requirement Curve — On July 9, 2021, the Court of Appeals for the D.C. Circuit issued a decision denying in part and granting in part an appeal by several PJM state consumer advocates regarding FERC's order approving revisions to PJM's Variable Resource Requirement Curve ("VRR"). The VRR is the demand curve that represents the slope of bids in the auction that ultimately results in the price and quantity of capacity allocated to load-serving entities, including NRG. The VRR curve is based on several inputs, including the Net CONE. The court upheld PJM's use of a greenfield gas-fired combustion turbine as the reference unit to establish Net CONE. However, the court remanded back to FERC the issue of allowing generators to have a 10% adder to their offer to supply capacity in the PJM market. The outcome could affect PJM's capacity market prices.

PJM Revisions to Minimum Offer Price Rule — On July 30, 2021, PJM filed a proposed tariff change at FERC to largely eliminate the current minimum offer price rules ("MOPR") except in very narrow cases. The proposal would eliminate: (i) the current MOPR for new entrant natural gas resources effective with the 2023/2024 delivery year and (ii) the expanded MOPR established in FERC's December 2019 Order to address out-of-market subsidies. On September 30, 2021, PJM's proposal went into effect by operation of law because the FERC Commissioners were split 2-2 as to the lawfulness of the change. Multiple parties filed motions for rehearing. The proposed revisions would allow PJM to address specific and narrow instances of buyer-side market power through subsequent filings at FERC. Any changes to the PJM capacity market construct may impact the outcome of future Base Residual Auctions. On October 25, 2021, FERC accepted PJM's request for a delay of the Base Residual Auction for the 2023/2024 Delivery Year from December 1, 2021 until January 25, 2022.

PJM's ORDC Filing and Compliance Directives — On March 29, 2019, PJM proposed energy and reserve market reforms to enhance price formation in reserve markets, which includes modifying its ORDC and aligning market-based reserve products in Day-Ahead and Real-Time markets. On May 21, 2020, FERC approved PJM's proposed energy and reserve market reforms. FERC also directed PJM to implement a forward-looking Energy and Ancillary Services Offset to be used in PJM's capacity markets. PJM submitted a compliance filing to revise its tariff on August 5, 2020. On November 12, 2020, FERC approved two PJM compliance filings regarding PJM's reserve markets and the forward-looking Energy and Ancillary Services Offset. Parties filed appeals at the Court of Appeals for the D.C. Circuit of FERC's orders, and on August 13, 2021, FERC filed a motion to voluntary remand the case back to the agency. PJM has delayed the implementation of the forward-looking Energy and Ancillary Services Offset until October 1, 2022.

Independent Market Monitor Market Seller Offer Cap Complaint — On February 21, 2019, the Independent Market Monitor filed a complaint alleging that the current Market Seller Offer Cap is too high. A number of parties, including PJM, filed protests to the filing arguing that, among other things, the Market Monitor failed to support its claim that the expected number of performance hours used to calculate the cap is overstated. On March 18, 2021, finding that the calculation of the default Market Seller Offer Cap was unjust and unreasonable, the Order permitted the current PJM May 2021 capacity auction for the 2022/2023 delivery rule to continue under the existing rules and set a procedural schedule for parties to file briefs with possible solutions. On September 2, 2021, FERC issued an order adopting the PJM Independent Market Monitor's proposal, which effectively eliminates the Market Seller Offer Cap except in very limited situations and requires unit specific cost review by the Independent Market Monitor for the majority of offers into the auctions. As required by the Order, PJM submitted its compliance tariff on October 4, 2021. On October 4, certain parties filed a motion for rehearing. The removal of the Offer Caps may impact the outcome of future Base Residual Auctions.

Indiana Municipal Power Agency and City of Lawrenceburg, Indiana Complaint on Station Power — On September 17, 2020, FERC issued an order in response to a complaint and request for declaratory judgement challenging the station power wholesale netting provisions in PJM's tariff. FERC found that it does not have jurisdiction over the supply of station power and the provision of station power is a retail sale subject to state jurisdiction. The order established a Section 206 proceeding and required PJM to submit a filing to show why the station service netting provisions of its tariff are just and reasonable. Lawrenceburg Power, LLC filed for rehearing, which was denied by operation of law on November 19, 2020 and they subsequently appealed to the D.C. Circuit. The matter is pending. On November 23, 2020, PJM submitted its station power compliance filing to FERC. In an April 27, 2021 Order, FERC found that PJM's Tariff regarding station power netting was unjust and unreasonable, but accepted in part and rejected in part PJM's compliance filing, and required PJM to make an additional compliance filing within 30 days of the Order. On May 27, 2021, PJM made an additional compliance filing. This decision could affect the rates that plants pay for station power.

New England

Changes to Capacity Markets — FERC held a technical conference on Modernizing Electric Market Design for the New England markets on May 25, 2021. ISO-NE leadership represented that they would work on Minimum Offer Price Rule and other related matters with the expectation of making a filing for FERC's consideration in early 2022. ISO-NE and market participants continue to discuss ISO-NE's proposal to eliminate the Minimum Offer Price Rule in the stakeholder process. Changes to the Forward Capacity Market's mitigation rules may impact the outcome of future Forward Capacity Auctions.

New York

Changes to Capacity Markets — The NYISO and stakeholders are discussing potential capacity market rule changes that may significantly alter the applicability of existing Buyer Side Mitigation rules as well as capacity accreditation. The NYISO plans to file a proposal regarding the capacity market mitigation reforms by late 2021. Changes to NYISO's Buyer Side Mitigation rules may impact the outcome of future capacity auctions.

California

California Resource Adequacy Proceedings — Since a summer 2020 heat storm that resulted in emergency load curtailments, the State of California and CAISO have embarked on numerous new regulatory activities while redirecting existing proceedings related to the topic of resource adequacy. On March 25, 2021, the CPUC directed the state's major investor-owned utilities to engage in up to 1.5 GW of emergency procurement for 2021 and 2022 and is currently evaluating further procurement directives through 2023. In the same docket, the CPUC approved a new demand response program for use during emergency conditions. As part of the Integrated Resource Procurement docket, the CPUC approved a decision on June 24, 2021 that will require all Load Serving Entities to procure a pro rata share of 11.5 GW of new non-fossil resource adequacy from 2023 to 2026. To replace the retiring Diablo Canyon nuclear plant, this will consist largely of GHG-free energy, long-duration storage, baseload renewables and energy storage. The CPUC and CAISO are also proposing major structural reforms of the resource adequacy program in California that would begin in 2024.

Midway-Sunset Reliability Must Run Proceeding — San Joaquin Energy, LLC, a subsidiary of NRG, owns a 50%, non-controlling interest in the Midway-Sunset Cogeneration Company ("MSCC"). MSCC owns a cogeneration facility near Fellows, California and submitted mothball notices for the cogeneration facility to the CAISO in the latter half of 2020. On December 17, 2020, the CAISO Board effectively rejected the mothball notices by authorizing its staff to designate the MSCC facility as a reliability must-run ("RMR") resource conditioned on execution of a RMR contract. On September 27, 2021, the CAISO gave notice to MSCC extending the term of the RMR Agreement through December 31, 2022. On January 29, 2021, MSCC made its RMR filing at FERC. Multiple parties filed protests and on March 16, 2021, MSCC filed a response to those protests. On April 2, 2021, FERC accepted the RMR filing, suspended it to become effective February 1, 2021 subject to refund and established hearing and settlement judge proceedings. The parties are engaging in settlement proceedings.

Canada

Alberta Energy Market — In December 2020, prior to its acquisition by NRG, Direct Energy filed a Non-Energy Rate Application with the Alberta Utilities Commission ("AUC") to approve cost recovery for the 2020-2022 period. Major cost elements of this application relate to bad debt, corporate costs, and customer care and billing contracts. The Company engaged in a mediation and settlement process, and on April 20, 2021 an all-party settlement was executed, and was filed with the AUC on April 23, 2021. The AUC approved the settlement agreement on June 4, 2021. Separately, the Company received approval from the AUC of a negotiated rate settlement for its electricity focused 2020-2022 Energy Price Setting Plan which went into effect on July 1, 2021. The Company has completed the last repayment to the Balancing Pool and the Alberta government as part of its 90-day utility bill deferral program. This program, effective March 18, 2020, was designed to assist residential, farms, and small business customers who were negatively affected by COVID-19 related economic circumstances by temporarily deferring their utility bill payments. The program was also designed to mitigate bad debt risks associated with the implementation of the program.

Environmental Regulatory Matters

NRG is subject to numerous environmental laws in the development, construction, ownership and operation of power plants. These laws generally require that governmental permits and approvals be obtained before construction and maintained during operation of power plants. Federal and state environmental laws historically have become more stringent over time. Future laws may require the addition of emissions controls or other environmental controls or impose restrictions on the Company's operations. Complying with environmental laws often involves specialized human resources and significant capital and operating expenses, as well as occasionally curtailing operations. The COVID-19 pandemic may prevent the Company from complying with certain of its environmental requirements, which federal and state regulators have recognized. 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 affect the Company have been revised recently by the EPA, including ash storage and disposal requirements, NAAQS revisions and implementation and effluent limitation guidelines. Some of these recent revisions may, in turn, be revised by the new U.S. presidential administration. NRG will evaluate the impact of these regulations as they are revised but cannot fully predict the impact of each until anticipated revisions and legal challenges are resolved. The Company's environmental matters are described in the Company's 2020 Form 10-K in Item 1, Business - *Environmental Matters* and Item 1A, Risk Factors. These matters have been updated in Note 18, *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 may become more stringent. The Company maintains a comprehensive compliance strategy to address continuing and new requirements. Complying with increasingly stringent air regulations could require the installation of additional emissions control equipment at some NRG facilities or retiring of units if installing such controls is not economic. Significant changes to air regulatory programs affecting the Company are described below.

CPP/ACE Rules — The attention in recent years on GHG emissions has resulted in federal and state regulations. In October 2015, the EPA promulgated the CPP, addressing GHG emissions from existing EGUs. On February 9, 2016, the U.S. Supreme Court stayed the CPP. In July 2019, EPA promulgated the ACE rule, which rescinded the CPP, which had sought to broadly regulate CO_2 emissions from the power sector. On January 19, 2021, the D.C. Circuit vacated the ACE rule (but on February 22, 2021, at the EPA's request, stayed the issuance of the portion of the mandate that would vacate the repeal of the CPP). On October 29, 2021, the U.S. Supreme Court agreed to review the D.C. Circuit's decision, which should provide some clarity regarding the scope of the EPA's authority to regulate CO_2 under the Clean Air Act. The Company expects the EPA to promulgate a new rule to regulate GHG emissions from power plants after a decision from the U.S. Supreme Court.

Byproducts, Wastes, Hazardous Materials and Contamination

In April 2015, the EPA finalized the rule regulating byproducts of coal combustion (e.g., ash and gypsum) as solid wastes under the RCRA. In September 2017, the EPA agreed to reconsider the rule. On July 30, 2018, the EPA promulgated a rule that amended the 2015 ash rule by extending some of the deadlines and providing more flexibility for compliance. On August 21, 2018, the D.C. Circuit found, among other things, that the EPA had not adequately regulated unlined ponds and legacy ponds. In 2019 and 2020, the EPA proposed several changes to this rule. On August 28, 2020, the EPA finalized "A Holistic Approach to Closure Part A: Deadline to Initiate Closure," which amended the April 2015 Rule to address the August 2018 D.C. Circuit decision and extend some of the deadlines. On November 12, 2020, the EPA finalized "A Holistic Approach to Closure Part B: Alternative Demonstration for Unlined Surface Impoundments," which further amended the April 2015 Rule to, among other things, provide procedures for requesting approval to operate existing ash impoundments with an alternate liner. The Company has updated its estimates of required environmental capital expenditures to address this revised rule.

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws, a current or previous owner or operator of a facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products. NRG may be responsible for property damage, personal injury and investigation and remediation costs incurred by a party in connection with hazardous material releases or threatened releases. These laws impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and the courts have interpreted liability under such laws to be strict (without fault) and joint and several. Cleanup obligations can often be triggered during the closure or decommissioning of a facility, in addition to spills during its operations. Further discussions of affected NRG sites can be found in Note 16, *Commitments and Contingencies*, to the condensed consolidated financial statements.

Nuclear Waste — The federal government's program to construct a nuclear waste repository at Yucca Mountain, Nevada was discontinued in 2010. Since 1998, the U.S. DOE has been in default of the federal government's obligations to begin accepting spent nuclear fuel, or SNF, and high-level radioactive waste, or HLW, under the Nuclear Waste Policy Act. Owners of nuclear plants, including the owners of STP, had been required to enter into contracts setting out the obligations of the owners and the U.S. DOE, including the fees to be paid by the owners for the U.S. DOE's services to license a spent fuel repository. Effective May 16, 2014, the U.S. DOE stopped collecting the fees.

On February 5, 2013, STPNOC entered into a settlement agreement with the U.S. DOE for payment of damages relating to the U.S. DOE's failure to accept SNF and HLW under the Nuclear Waste Policy Act through December 31, 2013, which has been extended three times through addendums to cover payments through December 31, 2022. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the U.S., nor has the NRC licensed any such facilities. STPNOC currently stores all SNF generated by its nuclear generating facilities on-site. STPNOC plans to continue to assert claims against the U.S. DOE for damages relating to the U.S. DOE's failure to accept SNF and HLW.

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended in 1985, the state of Texas is required to provide, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the state. Texas is currently in a compact with the state of Vermont, and the compact low-level waste facility located in Andrews County in Texas has been operational since 2012.

Water

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

Effluent Limitations Guidelines — In November 2015, the EPA revised the Effluent Limitations Guidelines for Steam Electric Generating Facilities, which imposed more stringent requirements (as individual permits were renewed) for wastewater streams from FGD, fly ash, bottom ash, and flue gas mercury control. On September 18, 2017, the EPA promulgated a final rule that, among other things, postponed 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 amended the rule. On October 13, 2020, the EPA amended the 2015 ELG rule by: (i) altering the stringency of certain limits for FGD wastewater; (ii) relaxing the zero-discharge requirement for bottom ash transport water; and (iii) changing several deadlines. On July 26, 2021, the EPA announced that it is initiating a new rulemaking to evaluate revising the ELG rule. While the EPA is developing the new rule, the existing rule (as amended in 2020) will stay in place, and the EPA expects permitting authorities to continue to implement the current regulation. The EPA anticipates releasing a proposed rule in fall 2022. In October 2021, NRG informed its regulators that the Company intends to comply with the ELG by ceasing combustion of coal by the end of 2028 at its domestic coal units outside of Texas, and installing appropriate controls by the end of 2025 at its two plants in Texas.

Regional Environmental Developments

Ash Regulation in Illinois — On July 30, 2019, Illinois enacted legislation that requires the state to promulgate regulations regarding coal ash at surface impoundments. On April 15, 2021, the state promulgated the implementing regulation, which became effective on April 21, 2021. The new regulation requires NRG to apply for initial operating permits for its coal ash surface impoundments by October 31, 2021 and construction permits (for closure) starting in 2022.

Significant Events

The following significant events have occurred during 2021 as further described within this Management's Discussion and Analysis and the condensed consolidated financial statements:

Financing Activities

On August 23, 2021, the Company issued $1,100 million of aggregate principal amount at par of 3.875% senior notes due 2032 (the "2032 Senior Notes"). The 2032 Senior Notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. The 2032 Senior Notes were issued under NRG's Sustainability-Linked Bond Framework, which sets out certain sustainability targets, including reducing greenhouse gas emissions. Failure to meet such sustainability targets will result in a 25 basis point increase to the interest rate payable on the 2032 Senior Notes from and including August 15, 2026.

On August 24, 2021, the Company redeemed $1,355 million in aggregate principal of its Senior Notes for $1,425 million using the proceeds of the 2032 Senior Notes and cash on hand, resulting in total deleveraging of $255 million. In connection with the redemptions, a $57 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $9 million, during the nine months ended September 30, 2021. As a result of these financing activities, annualized interest savings are expected to be approximately $53 million. The Company redeemed an additional $500 million of its 6.625% Senior Notes due 2027 during October 2021.

Extreme Weather Event in Texas During February 2021

During February 2021, Texas experienced unprecedented cold temperatures for a prolonged duration, resulting in a power emergency, blackouts, and an estimated all-time peak demand of 77 GW (without load shed). Ahead of the event, NRG launched residential customer communications calling for conservation across all of its brands, and initiated residential and commercial and industrial demand response programs to curtail customer load. The Company maximized available generating capacity and brought in additional resources to supplement in-state staff with technical and operating experts from the rest of its U.S. fleet.

During the nine months ended September 30, 2021, Winter Storm Uri's financial impact to loss before income taxes was a loss of $1.1 billion. A number of factors may mitigate or increase the financial impact, such as recently passed regulatory securitization packages, finalizing meter and settlement data, potential customer and counterparty risk including ERCOT's shortfall payments and uplift charges, and one-time cost savings.

Direct Energy Acquisition

On January 5, 2021, the Company acquired Direct Energy, a North American subsidiary of Centrica. Direct Energy is a leading retail provider of electricity, natural gas, and home and business energy related products and services in North America, with operations in all 50 U.S. states and 8 Canadian provinces. The acquisition increases NRG's retail portfolio by over 3 million customers and complements its integrated model. It also broadens the Company's presence in the Northeast and into states and locales where it does not currently operate, supporting NRG's objective to diversify its business.

The Company paid an aggregate purchase price of $3.625 billion in cash and an initial purchase price adjustment of $77 million. The Company funded the purchase price using a combination of $715 million of cash on hand, $166 million from a draw on its Revolving Credit Facility (of which $107 million was used to fund acquisition costs and financing fees that are not included in the aggregate purchase price above), as well as approximately $2.9 billion in secured and unsecured corporate debt issued in December 2020. The purchase price adjustment resulted in a reduction of $3 million, which is in negotiation with Centrica. The Company expects to receive this payment from Centrica during 2021. NRG expects to realize annual synergies of $175 million, $225 million, and $300 million in 2021, 2022, and 2023, respectively.

Limestone Extended Outage

In early July 2021, Limestone Unit 1 came offline as a result of damage to the duct work associated with the flue gas desulfurization system. Based on management's current assessment of necessary remediation efforts, Unit 1 is expected to remain on an outage until the second quarter of 2022.

Retirement of 1,600 MWs of PJM coal capacity

During the second quarter of 2021, the results of the PJM Base Residual Auction for the 2022/2023 delivery year were released, leading the Company to announce the near-term retirement of a significant portion of its PJM coal generating assets in June 2022. On July 30, 2021, PJM identified reliability impacts resulting from the proposed deactivation of one of those assets, Indian River Unit 4. On August 27, 2021 the Company notified PJM that it would continue operations at Indian River Unit 4 until the reliability upgrades identified by PJM were completed, provided that the unit receives a satisfactory and compensatory 'reliability must run' arrangement. The Company recorded impairment losses of $271 million and $35 million on the PJM generating assets and Midwest Generation goodwill, respectively, in connection with the decline in PJM capacity prices and the near-term retirement dates of certain assets, Note 8, *Impairments*. The Company is continuing to evaluate the viability of the remaining PJM generating assets in light of the auction results.

Sale of Agua Caliente

On February 3, 2021, the Company completed the sale of its 35% ownership in Agua Caliente to Clearway Energy, Inc. for $202 million. NRG recognized a gain on the sale of $17 million, including cash disposed of $7 million. On October 21, 2019, the Company had repaid the Agua Caliente Borrower 1 notes associated with the project of $83 million.

Sale of 4.8 GW of Fossil Generation Assets

On February 28, 2021, the Company entered into a definitive purchase agreement with Generation Bridge, an affiliate of ArcLight Capital Partners, to sell approximately 4,850 MW of fossil generating assets from its East and West regions of operations for total proceeds of $760 million, subject to standard purchase price adjustments and certain other indemnifications. The purchase price adjustments will include a working capital deduction for cash flows generated of approximately $11 million per month from the beginning of the year until the closing of the transaction, in lieu of cash flows generated during the year. As part of the transaction, NRG is entering into a tolling agreement for its 866 MW Arthur Kill plant in New York City through April 2025.

The transaction is expected to close by the end of 2021 and is subject to various closing conditions, approvals and consents, including approval from the NYPSC. The transaction has received FERC approval and approval under the Hart-Scott-Rodino Act.

Renewable Power Purchase Agreements

The Company's strategy is to procure mid to long-term generation through power purchase agreements. As of September 30, 2021, NRG has entered into PPAs totaling approximately 2.7 GW with third-party project developers and other counterparties. The tenor of these agreements is an average of twelve years. The Company expects to continue evaluating and executing similar agreements that support the needs of the business.

COVID-19

As the COVID-19 pandemic continues, NRG remains focused on protecting the health and well-being of its employees, while supporting its customers and the communities in which it operates and assuring the continuity of its operations. During 2020, NRG migrated a substantial portion of its employees to a remote work environment. The first COVID-19 vaccine became available in the United States in December 2020. Vaccines have become increasingly accessible since the initial rollout and all adults across the nation became eligible to receive a vaccine as of April 19, 2021. The Company has completed its phased approach to return employees to the offices following a set of safety protocols to ensure employee well-being.

While the pandemic presents risks to the Company's business, as further described in the Company's 2020 Form 10-K in Part II, Item 1A — *Risk Factors*, there was not a material adverse impact on the Company's results of operations for the nine months ended September 30, 2021. NRG believes it has sufficient liquidity on hand to continue business operations in light of current circumstances posed by the pandemic. As disclosed in the Liquidity and Capital Resources section, the Company has total available liquidity of $3.3 billion as of September 30, 2021, consisting of cash on hand, its Revolving Credit Facility, and additional facilities.

The situation surrounding COVID-19 remains fluid and the potential for a material adverse impact on the Company exists as long as the virus impacts the level of economic activity in the United States and abroad. While the Company expects the risk to decrease as vaccinations continue to be administered, NRG cannot reasonably estimate with any degree of certainty the full impact COVID-19, nor any resurgence of COVID-19, may have on the Company's results of operations, financial position, and liquidity. The extent to which the COVID-19 pandemic may impact the Company's business, operating results, financial condition, risk exposure or liquidity will depend on future developments, including the duration of the pandemic, travel restrictions, business and workforce disruptions, any resurgence of the pandemic and the effectiveness of actions taken to contain, mitigate and treat the disease.

Trends Affecting Results of Operations and Future Business Performance

Except as set forth below, the Company's trends are described in the Company's 2020 Form 10-K in Item 7, M*anagement's Discussion and Analysis of Financial Condition and Results of Operations - Business Environment.*

Global Supply Chain Disruptions — There are currently global supply chain disruptions impacting natural gas, coal and other fuels and materials necessary for the production and sale of electricity to our retail customers. These supply chain disruptions are due in part to increased demand driven by a number of factors outside the Company's control including the COVID-19 pandemic, labor shortages and extreme weather events in the United States. These factors are impacting the dispatch of generation facilities, as well as the costs to serve our retail customers in the markets in which we operate. The Company expects supply chain disruptions will continue throughout the remainder of 2021 and into 2022. We are working closely with our suppliers and customers to minimize any potential adverse impacts of these events. We will continue to actively monitor all direct and indirect potential impacts of the supply chain disruptions, and will seek to mitigate and minimize their impact on our business.

Changes in Accounting Standards

See Note 2, *Summary of Significant Accounting Policies*, for a discussion of recent accounting developments.

Consolidated Results of Operations

The following table provides selected financial information for the Company:

(In millions, except as otherwise noted)	Three months ended September 30, 2021	2020	Change	Nine months ended September 30, 2021	2020	Change
Operating Revenues						
Retail revenue	$ 5,951	$ 2,302	$ 3,649	$ 16,929	$ 5,795	$11,134
Energy revenue[a]	336	222	114	989	429	560
Capacity revenue[a]	189	174	15	615	518	97
Mark-to-market for economic hedging activities	3	39	(36)	(99)	78	(177)
Contract amortization	(3)	—	(3)	(19)	—	(19)
Other revenues[a][b]	133	72	61	1,528	246	1,282
Total operating revenues	6,609	2,809	3,800	19,943	7,066	12,877
Operating Costs and Expenses						
Cost of fuel	465	300	(165)	1,530	666	(864)
Purchased power	3,212	439	(2,773)	9,039	1,162	(7,877)
Other cost of sales [c]	1,430	776	(654)	5,735	1,971	(3,764)
Mark-to-market for economic hedging activities	(1,782)	157	1,939	(4,122)	65	4,187
Contract and emissions credit amortization [c]	(45)	2	47	19	4	(15)
Operations and maintenance	332	265	(67)	1,036	837	(199)
Other cost of operations	80	95	15	259	220	(39)
Cost of operations (excluding depreciation and amortization shown below)	3,692	2,034	(1,658)	13,496	4,925	(8,571)
Depreciation and amortization	199	99	(100)	569	318	(251)
Impairment losses	—	29	29	306	29	(277)
Selling, general and administrative costs	318	216	(102)	973	592	(381)
Provision for credit losses	64	26	(38)	715	74	(641)
Acquisition-related transaction and integration costs	17	12	(5)	81	13	(68)
Total operating costs and expenses	4,290	2,416	(1,874)	16,140	5,951	(10,189)
Gain on sale of assets	—	—	—	17	6	11
Operating Income	2,319	393	1,926	3,820	1,121	2,699
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	15	36	(21)	23	37	(14)
Impairment losses on investments	—	—	—	—	(18)	18
Other income, net	8	11	(3)	42	52	(10)
Loss on debt extinguishment, net	(57)	—	(57)	(57)	(1)	(56)
Interest expense	(122)	(99)	(23)	(374)	(292)	(82)
Total other expense	(156)	(52)	(104)	(366)	(222)	(144)
Income Before Income Taxes	2,163	341	1,822	3,454	899	2,555
Income tax expense	545	92	(453)	840	216	(624)
Net Income	$ 1,618	$ 249	$ 1,369	$ 2,614	$ 683	$ 1,931
Business Metrics						
Average natural gas price — Henry Hub ($/MMBtu)	$ 4.01	$ 1.98	103 %	$ 3.18	$ 1.88	69 %

(a) Includes gains and losses from financially settled transactions
(b) Includes trading gains and losses and ancillary revenues
(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 September 30, 2021 and 2020

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 September 30, 2021 and 2020. The average on-peak power prices increased across the regions for the three months ended September 30, 2021 as compared to the same period in 2020 as a result of higher natural gas prices.

	Average on Peak Power Price ($/MWh)		
	Three months ended September 30,		
Region	2021	2020	Change %
Texas			
ERCOT - Houston[a]	$ 47.11	$ 28.59	65 %
ERCOT - North[a]	46.16	27.91	65 %
East			
NY J/NYC[b]	$ 54.75	$ 27.32	100 %
NEPOOL[b]	52.57	27.20	93 %
COMED (PJM)[b]	48.36	25.82	87 %
PJM West Hub[b]	51.32	28.24	82 %
West			
MISO - Louisiana Hub[b]	$ 44.95	$ 24.83	81 %
CAISO - SP15[b]	72.02	61.94	16 %

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

The following table summarizes average realized power prices for NRG, including the impact of settled hedges, for the three months ended September 30, 2021 and 2020:

	Average Realized Power Price ($/MWh)		
	Three months ended September 30,		
Segment	2021	2020	Change %
East[a]	$ 37.26	$ 31.23	19 %
West/Services/Other	50.31	48.39	4 %

(a) Average Realized Power Price reflects energy sales from the generation fleet, omitting sales to the retail component of the East Segment. Intercompany financial transactions hedging generation with the retail business make up ($9.84)/MWh in the three months ended September 30, 2021 and $4.09/MWh in the three months ended September 30, 2020

The average realized power prices increased in East and West/Services/Other for the three months ended September 30, 2021 as compared to the same period in 2020, as a result of the Company's multi-year hedging program and higher natural gas prices.

Gross Margin

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

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 fuel, purchased power and other cost of sales. Economic gross margin does not include mark-to-market gains or losses on economic hedging activities, contract and emissions credit amortization, or depreciation and amortization, operations and maintenance, or other cost of operations.

The below tables present the composition and reconciliation of gross margin and economic gross margin for the three months ended September 30, 2021 and 2020:

	Three months ended September 30, 2021				
($ In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate/ Eliminations**	**Total**
Retail revenue	$ 2,503	$ 2,698	$ 750	$ —	$ 5,951
Energy revenue	18	201	113	4	336
Capacity revenue	—	172	17	—	189
Mark-to-market for economic hedging activities	(1)	(3)	(6)	13	3
Contract amortization	—	(7)	4	—	(3)
Other revenue[(a)]	115	16	6	(4)	133
Operating revenue	2,635	3,077	884	13	6,609
Cost of fuel	(305)	(93)	(69)	1	(466)
Purchased power	(583)	(2,295)	(331)	(2)	(3,211)
Other cost of sales[(b)(c)(d)]	(909)	(194)	(327)	—	(1,430)
Mark-to-market for economic hedging activities	(81)	1,786	90	(13)	1,782
Contract and emission credit amortization	(7)	61	(9)	—	45
Depreciation and amortization	(84)	(88)	(20)	(7)	(199)
Gross margin	**$ 666**	**$ 2,254**	**$ 218**	**$ (8)**	**$ 3,130**
Less: Mark-to-market for economic hedging activities, net	(82)	1,783	84	—	1,785
Less: Contract and emission credit amortization, net	(7)	54	(5)	—	42
Less: Depreciation and amortization	(84)	(88)	(20)	(7)	(199)
Economic gross margin	**$ 839**	**$ 505**	**$ 159**	**$ (1)**	**$ 1,502**

(a) Includes trading gains and losses and ancillary revenues

(b) Includes capacity and emissions credits

(c) Includes $802 million and $8 million of TDSP expense in Texas and East, respectively

(d) Excludes depreciation and amortization shown separately

Business Metrics	Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Retail sales					
Home electricity sales volume (GWh)	13,486	4,032	512		18,030
Business electricity sales volume (GWh)	10,583	14,794	2,672		28,049
Home natural gas sales volume (MDth)	—	5,148	6,580		11,728
Business natural gas sales volume (MDth)	—	334,503	20,666		355,169
Average retail Home customer count (in thousands) [(a)]	3,030	1,819	960		5,809
Ending retail Home customer count (in thousands) [(a)]	3,043	1,784	954		5,781
Power generation					
GWh sold	11,841	4,267	2,246		18,354
GWh generated:[(b)]					
Coal	5,558	2,375	—		7,933
Gas	3,756	750	1,970		6,476
Nuclear	2,527	—	—		2,527
Oil	—	106	—		106
Total	11,841	3,231	1,970		17,042

(a) Home customer count includes recurring residential customers and municipal aggregations, as well as recurring Services customers

(b) Includes owned and leased generation, as well as tolls, and excludes equity investments

($ In millions)	Three months ended September 30, 2020				
	Texas	East	West/ Services/Other	Corporate/ Eliminations	Total
Retail revenue	$ 1,921	$ 354	$ 27	$ —	$ 2,302
Energy revenue	11	93	117	1	222
Capacity revenue	—	158	16	—	174
Mark-to-market for economic hedging activities	1	43	(10)	5	39
Other revenue	59	18	(1)	(4)	72
Operating revenue	1,992	666	149	2	2,809
Cost of fuel	(206)	(58)	(36)	—	(300)
Purchased power	(287)	(140)	(13)	1	(439)
Other cost of sales[(a)(b)(c)]	(647)	(103)	(26)	—	(776)
Mark-to-market for economic hedging activities	(153)	2	(1)	(5)	(157)
Contract and emission credit amortization	(2)	—	—	—	(2)
Depreciation and amortization	(49)	(33)	(10)	(7)	(99)
Gross margin	**$ 648**	**$ 334**	**$ 63**	**$ (9)**	**$ 1,036**
Less: Mark-to-market for economic hedging activities, net	(152)	45	(11)	—	(118)
Less: Contract and emission credit amortization, net	(2)	—	—	—	(2)
Less: Depreciation and amortization	(49)	(33)	(10)	(7)	(99)
Economic gross margin	**$ 851**	**$ 322**	**$ 84**	**$ (2)**	**$ 1,255**

(a) Includes capacity and emissions credits

(b) Includes $595 million and $3 million of TDSP expense in Texas and East, respectively

(c) Excludes depreciation and amortization shown separately

Business Metrics					
Retail sales					
Home electricity sales volume (GWh)	12,849	3,028	—		15,877
Business electricity sales volume (GWh)	4,886	439	—		5,325
Home natural gas sales volume (MDth)	—	1,850	—		1,850
Average retail Home customer count (in thousands)[(a)]	2,452	1,154	—		3,606
Ending retail Home customer count (in thousands)[(a)]	2,460	1,139	—		3,599
Power generation					
GWh sold	11,294	3,426	2,418		17,138
GWh generated[(b)]					
Coal	5,265	1,110	—		6,375
Gas	3,102	1,089	2,200		6,391
Nuclear	2,531	—	—		2,531
Oil	—	174	—		174
Total	10,898	2,373	2,200		15,471

(a) Home customer count includes recurring residential customers and municipal aggregations

(b) Includes owned and leased generation, and excludes equity investments

The table below represents the weather metrics for the three months ended September 30, 2021 and 2020:

	Three months ended September 30,		
Weather Metrics	**Texas**	**East**	**West/Services/ Other [b]**
2021			
CDDs [a]	1,589	784	1,134
HDDs [a]	—	38	5
2020			
CDDs	1,640	874	1,152
HDDs	6	72	4
10-year average			
CDDs	1,690	818	1,159
HDDs	2	56	10

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

(b) The West/Services/Other weather metrics are comprised of the average of the CDD and HDD regional results for the West - California and West - South Central regions

Gross Margin and Economic Gross Margin

Gross margin increased $2.1 billion and economic gross margin increased $247 million during the three months ended September 30, 2021, compared to the same period in 2020.

The tables below describe the changes in gross margin and economic gross margin by segment:

Texas

	(In millions)
Higher gross margin due to Winter Storm Uri, primarily due to ERCOT 180 day settlements	$ 13
The following explanations exclude the impact of Winter Storm Uri:	
Lower gross margin primarily due to a 20% increase in overall average costs to serve the retail load, driven primarily by increases in power and fuel costs of $110 million; partially offset by increased net revenue rates as a result of changes in customer term, product and mix of $0.60 per MWh, or $12 million	(98)
Lower net revenue due to a decrease in load of 290,000 MWhs from weather	(24)
Higher gross margin due to increased volumes from the acquisition of Direct Energy in January 2021	59
Higher gross margin from market optimization activities	29
Higher net revenue due to customer mix	4
Other	5
Decrease in economic gross margin	$ (12)
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	70
Increase in contract and emission credit amortization	(5)
Increase in depreciation and amortization	(35)
Increase in gross margin	**$ 18**

East

	(In millions)	
Higher gross margin due to increased volumes from the acquisition of Direct Energy in January 2021, including \$153 million from power and \$59 million from natural gas	$	212
Higher gross margin from market optimization activities		6
Higher gross margin due to an 18% increase in PJM capacity volumes, partially offset by a 12% decrease in New England capacity prices and a 5% decrease in New York realized capacity prices		5
Lower gross margin from higher supply costs of \$11.75 per MWh, or \$39 million and lower volumes due to attrition, weather and customer mix of \$22 million, partially offset by higher revenue of \$5.75 per MWh, or \$19 million		(42)
Other		2
Increase in economic gross margin	$	183
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		1,738
Decrease in contract amortization		54
Increase in depreciation and amortization		(55)
Increase in gross margin	**$**	**1,920**

West/Services/Other

	(In millions)	
Higher gross margin due to increased volumes from the acquisition of Direct Energy in January 2021	$	104
Higher gross margin due to commercial optimization activities		12
Lower gross margin primarily due to prior year MISO uplift payments resulting from out-of-market dispatch during Hurricane Laura		(30)
Lower gross margin at the gas plants due to a 111% increase in fuel cost while realized power prices remained constant		(15)
Other		4
Increase in economic gross margin	$	75
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges		95
Increase in contract amortization		(5)
Increase in depreciation and amortization		(10)
Increase in gross margin	**$**	**155**

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 $1.9 billion during the three months ended September 30, 2021, compared to the same period in 2020.

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

	Three months ended September 30, 2021				
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Eliminations**	**Total**
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 1	$ (1)	$ 2	$ (1)	$ 1
Reversal of acquired (gain) positions related to economic hedges	—	(2)	—	—	(2)
Net unrealized (losses)/gains on open positions related to economic hedges	(2)	—	(8)	14	4
Total mark-to-market (losses)/gains in operating revenues	$ (1)	$ (3)	$ (6)	$ 13	$ 3
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (99)	$ (2)	$ 2	$ 1	$ (98)
Reversal of acquired (gain)/loss positions related to economic hedges	(47)	31	(24)	—	(40)
Net unrealized gains on open positions related to economic hedges	65	1,757	112	(14)	1,920
Total mark-to-market (losses)/gains in operating costs and expenses	$ (81)	$ 1,786	$ 90	$ (13)	$ 1,782

	Three months ended September 30, 2020				
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Eliminations**	**Total**
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized losses on settled positions related to economic hedges	$ 2	$ 25	$ 1	$ 1	$ 29
Net unrealized (losses)/gains on open positions related to economic hedges	(1)	18	(11)	4	10
Total mark-to-market gains/(losses) in operating revenues	$ 1	$ 43	$ (10)	$ 5	$ 39
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges	$ (128)	$ (1)	$ —	$ (1)	$ (130)
Reversal of acquired (gain)/loss positions related to economic hedges	(3)	1	—	—	(2)
Net unrealized (losses)/gains on open positions related to economic hedges	(22)	2	(1)	(4)	(25)
Total mark-to-market (losses)/gains in operating costs and expenses	$ (153)	$ 2	$ (1)	$ (5)	$ (157)

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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 September 30, 2021, the $3 million gain in operating revenues from economic hedge positions was driven primarily by an increase in the value of open positions. The $1.8 billion gain in operating costs and expenses from economic hedge positions was driven primarily by an increase in the value of open positions as a result of increases in natural gas and Northeast power prices, partially offset by the reversal of previously recognized unrealized gains on contracts that settled during the period and acquired contracts that settled during the period.

For the three months ended September 30, 2020, the $39 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 the value of open positions as a result of decreases in New York capacity prices. The $157 million loss in operating costs and expenses from economic hedge positions was driven primarily by the reversal of previously recognized unrealized gains on contracts that settled during the period as well as a decrease in the value of open positions as a result of increases in natural gas prices and ERCOT heat rate contraction.

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 September 30, 2021 and 2020. The realized and unrealized financial and physical trading results are included in operating revenue. The Company's trading activities are subject to limits based on the Company's Risk Management Policy.

	Three months ended September 30,	
(In millions)	**2021**	**2020**
Trading gains/(losses)		
Realized	$ 31	$ 3
Unrealized	8	(5)
Total trading gains/(losses)	$ 39	$ (2)

Operations and Maintenance Expense

Operations and maintenance expense are comprised of the following:

(In millions)	**Texas**	**East**	**West/Services/ Other**	**Corporate**	**Eliminations**	**Total**
Three months ended September 30, 2021	$ 160	$ 121	$ 52	$ —	$ (1)	$ 332
Three months ended September 30, 2020	147	94	23	2	(1)	265

Operations and maintenance expense increased by $67 million for the three months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to the acquisition of Direct Energy in January 2021	$ 66
Increase in major maintenance primarily due to the duration and scope of forced outages in Texas during the third quarter of 2021	9
Increase in variable operations and maintenance expense driven by higher generation at the PJM coal facilities in the third quarter of 2021	7
Decrease driven by lower retail operations costs	(8)
Decrease in lease expense primarily driven by the buyout of the lease at Midwest Generation in 2020	(6)
Other	(1)
Increase in operations and maintenance expense	$ 67

Other Cost of Operations

Other cost of operations are comprised of the following:

(In millions)	**Texas**	**East**	**West/Services/ Other**	**Total**
Three months ended September 30, 2021	$ 47	$ 31	$ 2	$ 80
Three months ended September 30, 2020	63	24	8	95

Other costs of operations decreased by $15 million for the three months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Decrease primarily due to ARO expense in 2020 at Jewett Mine as a result of regulatory requirements	$ (21)
Decrease due to lower gross receipt taxes driven by lower retail revenues in legacy brands	(5)
Increase due to the acquisition of Direct Energy in January 2021	16
Other	(5)
Decrease in other cost of operations	$ (15)

Depreciation and Amortization

Depreciation and amortization are comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Corporate	Total
Three months ended September 30, 2021	$ 84	$ 88	$ 20	$ 7	$ 199
Three months ended September 30, 2020	49	33	10	7	99

Depreciation and amortization increased by $100 million primarily due to amortization of acquired intangibles in connection with the acquisition of Direct Energy in January 2021.

Impairment Losses

Impairment losses of $29 million were recorded during the three months ended September 30, 2020 related to advanced negotiations to sell the Home Solar business, as further discussed in Note 8*, Impairments*.

Selling, General and Administrative Costs

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

(In millions)	Texas	East	West/Services/ Other	Corporate	Total
Three months ended September 30, 2021	$ 148	$ 110	$ 44	$ 16	$ 318
Three months ended September 30, 2020	129	68	16	3	216

Selling, general and administrative costs increased by $102 million for the three months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to the acquisition of Direct Energy in January 2021	$ 102
Increase due to higher consulting costs	6
Increase due to higher legal expenses related to Winter Storm Uri and medical expenses	5
Decrease due to the favorable resolution of a legal matter	(15)
Other	4
Increase in selling, general and administrative costs	$ 102

Provision for Credit Losses

Provision for credit losses are comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Total
Three months ended September 30, 2021	$ 58	$ 3	$ 3	$ 64
Three months ended September 30, 2020	24	1	1	26

Provision for credit losses increased by $38 million for the three months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to Winter Storm Uri, related to counterparty credit risk	$ 32
Increase due to the acquisition of Direct Energy in January 2021, partially offset by improved collections in the legacy brands	6
Increase in provision for credit losses	$ 38

Acquisition-Related Transaction and Integration Costs

Acquisition-related transaction and integration costs increased $5 million for the three months ended September 30, 2021 compared to the three months ended September 30, 2020 primarily due to the integration of Direct Energy in 2021.

Equity in earnings of unconsolidated affiliates

Equity in earnings of unconsolidated affiliates was $21 million lower for the three months ended September 30, 2021 compared to the three months ended September 30, 2020, primarily due to the sale of the Agua Caliente solar project in the first quarter of 2021 and unfavorable weather resulting in decreased earnings at Ivanpah in 2021.

Loss on debt extinguishment, Net

Loss on debt extinguishment of $57 million was recorded for the three months ended September 30, 2021, in connection with the redemption of senior notes, as further discussed in Note 9*, Long-term Debt and Finance Leases.*

Interest Expense

Interest expense increased by $23 million for the three months ended September 30, 2021, compared to the same period in 2020, primarily due to financings entered into in connection with the Direct Energy acquisition.

Income Tax Expense

For the three months ended September 30, 2021, an income tax expense of $545 million was recorded on a pre-tax income of $2.2 billion. For the same period in 2020, income tax expense of $92 million was recorded on pre-tax income of $341 million. The effective tax rates were 25.2% and 27.0% for the three months ended September 30, 2021 and 2020, respectively.

For the three months ended September 30, 2021, the effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense. For the same period in 2020, the effective tax rate was higher than the statutory rate of 21% due to state tax expense, partially offset by an excess tax benefit related to share-based compensation.

Management's discussion of the results of operations for the nine months ended September 30, 2021 and 2020

Electricity Prices

The following table summarizes average on peak power prices for each of the major markets in which NRG operates for the nine months ended September 30, 2021 and 2020. The average on-peak power prices increased significantly in Texas due to the impact from Winter Storm Uri. The average on-peak power prices increased in East and West/Services/Other due to higher gas prices.

	Average on Peak Power Price ($/MWh)		
	Nine months ended September 30,		
Region	**2021**	**2020**	**Change %**
Texas			
ERCOT - Houston [a]	$ 240.14	$ 26.09	820 %
ERCOT - North[a]	236.75	24.12	882 %
East			
NY J/NYC[b]	$ 45.04	$ 23.38	93 %
NEPOOL[b]	47.17	24.02	96 %
COMED (PJM)[b]	38.00	22.13	72 %
PJM West Hub[b]	40.04	23.84	68 %
West			
MISO - Louisiana Hub[b]	$ 40.11	$ 23.01	74 %
CAISO - SP15[b]	51.22	36.60	40 %

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

The following table summarizes average realized power prices for NRG, including the impact of settled hedges, for the nine months ended September 30, 2021 and 2020:

	Average Realized Power Price ($/MWh)		
	Nine months ended September 30,		
Segment	**2021**	**2020**	**Change %**
East[a]	$ 37.70	$ 33.92	11 %
West/Services/Other	39.97	35.18	14 %

(a) Average Realized Power Price reflects energy sales from the generation fleet, omitting sales to the retail component of the East Segment. Intercompany financial transactions hedging generation with the retail business make up ($5.10)/MWh in the nine months ended September 30, 2021 and $12.10/MWh in the nine months ended September 30, 2020

The average realized power prices fluctuated in the East and West/Services/Other at different rates for the nine months ended September 30, 2021, as compared to the same period in 2020, as a result of the Company's multi-year hedging program, increased natural gas prices and warmer June temperatures in California.

Winter Storm Uri

During the nine months ended September 30, 2021, Winter Storm Uri's financial impact to loss before income taxes was a loss of $1.1 billion. The following impacts are further discussed in the related sections below:

(In millions)	Nine months ended September 30, 2021
Gross margin - Texas	$ (560)
Gross margin - East	146
Gross margin - West/Services/Other	13
Total gross margin	(401)
Operations and maintenance expense	(2)
Selling, general and administrative costs	(29)
Provision for credit losses	(638)
Total impact to loss before income taxes	$ (1,070)

A number of factors may mitigate or increase the financial impact, such as recently passed regulatory securitization packages, potential customer and counterparty risk including ERCOT's shortfall payments and uplift charges, and one-time cost savings.

Gross Margin

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

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 fuel, purchased power and other cost of sales. Economic gross margin does not include mark-to-market gains or losses on economic hedging activities, contract and emissions credit amortization, depreciation and amortization, operations and maintenance, or other cost of operations.

The below tables present the composition and reconciliation of gross margin and economic gross margin for the nine months ended September 30, 2021 and 2020:

	Nine months ended September 30, 2021				
($ In millions)	Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Retail revenue	$ 6,575	$ 8,029	$ 2,326	$ (1)	$ 16,929
Energy revenue	317	428	238	6	989
Capacity revenue	—	568	47	—	615
Mark-to-market for economic hedging activities	(5)	(53)	(60)	19	(99)
Contract amortization	—	(15)	(4)	—	(19)
Other revenue [(a)]	1,475	45	17	(9)	1,528
Operating revenue	8,362	9,002	2,564	15	19,943
Cost of fuel	(1,243)	(155)	(133)	1	(1,530)
Purchased power	(1,978)	(6,140)	(919)	(2)	(9,039)
Other cost of sales [(b)(c)(d)]	(3,570)	(1,045)	(1,120)	—	(5,735)
Mark-to-market for economic hedging activities	1,072	2,849	220	(19)	4,122
Contract and emission credit amortization	—	(8)	(11)	—	(19)
Depreciation and amortization	(245)	(238)	(65)	(21)	(569)
Gross margin	**$ 2,398**	**$ 4,265**	**$ 536**	**$ (26)**	**$ 7,173**
Less: Mark-to-market for economic hedging activities, net	1,067	2,796	160	—	4,023
Less: Contract and emission credit amortization, net	—	(23)	(15)	—	(38)
Less: Depreciation and amortization	(245)	(238)	(65)	(21)	(569)
Economic gross margin	**$ 1,576**	**$ 1,730**	**$ 456**	**$ (5)**	**$ 3,757**

(a) Includes trading gains and losses and ancillary revenues

(b) Includes capacity and emissions credits

(c) Includes $2.0 billion and $24 million of TDSP expense in Texas and East, respectively

(d) Excludes depreciation and amortization shown separately

Business Metrics	Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Retail sales					
Home electricity sales volume (GWh)	34,304	11,137	1,649		47,090
Business electricity sales volume (GWh)	25,180	40,373	7,321		72,874
Home natural gas sales volume (MDth)	—	53,077	62,200		115,277
Business natural gas sales volume (MDth)	—	1,141,892	79,712		1,221,604
Average retail Home customer count (in thousands)[(a)]	3,059	1,871	968		5,898
Ending retail Home customer count (in thousands)[(a)]	3,043	1,784	954		5,781
Power generation					
GWh sold	29,020	10,000	5,954		44,974
GWh generated [(b)]					
Coal	14,188	4,887	—		19,075
Gas	7,789	1,324	5,606		14,719
Nuclear	7,043	—	—		7,043
Oil	—	189	—		189
Total	29,020	6,400	5,606		41,026

(a) Home customer count includes recurring residential customers and municipal aggregations, as well as recurring Services customers

(b) Includes owned and leased generation, as well as tolls, and excludes equity investments

($ In millions)	Nine months ended September 30, 2020 Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Retail revenue	$ 4,734	$ 996	$ 66	$ (1)	$ 5,795
Energy revenue	21	157	252	(1)	429
Capacity revenue	—	471	47	—	518
Mark-to-market for economic hedging activities	1	63	6	8	78
Other revenue	172	45	36	(7)	246
Operating revenue	4,928	1,732	407	(1)	7,066
Cost of fuel	(432)	(132)	(102)	—	(666)
Purchased Power	(755)	(389)	(22)	4	(1,162)
Other cost of sales [(a) (b) (c)]	(1,663)	(271)	(37)	—	(1,971)
Mark-to-market for economic hedging activities	(63)	7	(1)	(8)	(65)
Contract and emission credit amortization	(4)	—	—	—	(4)
Depreciation and amortization	(167)	(97)	(28)	(26)	(318)
Gross margin	**$ 1,844**	**$ 850**	**$ 217**	**$ (31)**	**$ 2,880**
Less: Mark-to-market for economic hedging activities, net	(62)	70	5	—	13
Less: Contract and emission credit amortization, net	(4)	—	—	—	(4)
Less: Depreciation and amortization	(167)	(97)	(28)	(26)	(318)
Economic gross margin	**$ 2,077**	**$ 877**	**$ 240**	**$ (5)**	**$ 3,189**

(a) Includes capacity and emissions credits

(b) Includes $1.5 billion and $8 million of TDSP expense in Texas and East, respectively

(c) Excludes depreciation and amortization shown separately

	Texas	East	West/Services/ Other	Corporate/ Eliminations	Total
Business Metrics					
Retail sales					
Home electricity sales volume (GWh)	30,360	7,931	—		38,291
Business electricity sales volume (GWh)	13,555	1,193	—		14,748
Natural gas sales volume (MDth)	—	15,949	—		15,949
Average retail Home customer count (in thousands)[(a)]	2,446	1,188	—		3,634
Ending retail Home customer count (in thousands)[(a)]	2,460	1,139	—		3,599
Power generation					
GWh sold	24,868	7,193	7,163		39,224
GWh generated [(b)]					
Coal	12,102	1,504	—		13,606
Gas	5,117	1,717	6,801		13,635
Nuclear	7,093	—	—		7,093
Oil	—	258	—		258
Total	24,312	3,479	6,801		34,592

(a) Home customer count includes recurring residential customers and municipal aggregations

(b) Includes owned and leased generation, and excludes equity investments

The table below represents the weather metrics for the nine months ended September 30, 2021 and 2020:

Weather Metrics	Nine months ended September 30, Texas	East	West/Services/Other [(b)]
2021			
CDDs [(a)]	2,574	1,184	1,693
HDDs [(a)]	1,202	2,929	1,398
2020			
CDDs	2,822	1,283	1,790
HDDs	867	2,751	1,176
10-year average			
CDDs	2,809	1,212	1,767
HDDs	998	2,974	1,270

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

(b) The West/Services/Other weather metrics are comprised of the average of the CDD and HDD regional results for the West-California and West-South Central regions

Gross Margin and Economic Gross Margin

Gross margin increased $4.3 billion and economic gross margin increased $568 million, both of which include intercompany sales, during the nine months ended September 30, 2021, compared to the same period in 2020.

The tables below describe the changes in gross margin and economic gross margin by segment:

Texas

	(In millions)
Lower gross margin due to Winter Storm Uri, primarily driven by an increase in unhedgeable ancillary and operating reserve demand curve	$ (560)
The following explanations exclude the impact of Winter Storm Uri:	
Lower gross margin due to a 14% increase in overall average costs to serve the retail load, driven primarily by increases in power and fuel costs, totaling $168 million; partially offset by higher net revenue rates as a result of changes in customer term, product and mix of $2 per MWh, or $96 million	(72)
Lower net revenue due to a decrease in load of 701,000 MWhs from weather	(60)
Lower net revenue due to attrition and customer mix	(52)
Higher gross margin due to increased volumes from the acquisition of Direct Energy in January 2021	227
Higher gross margin due to market optimization activities	14
Other	2
Decrease in economic gross margin	$ (501)
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	1,129
Decrease in contract and emission credit amortization	4
Increase in depreciation and amortization	(78)
Increase in gross margin	**$ 554**

East

	(In millions)
Higher gross margin due to Winter Storm Uri, primarily driven by natural gas optimization during volatile pricing that occurred during the weather event	$ 146
The following explanations exclude the impact of Winter Storm Uri:	
Higher gross margin due to increased volumes from the acquisition of Direct Energy in January 2021, including $335 million from power activity and $329 million from natural gas activity	664
Higher business demand response gross margin primarily from the early settlement of capacity obligations in 2021 compared to the same period in 2020	63
Higher gross margin due to a lower of cost or market adjustment on oil inventory in 2020	29
Higher gross margin from market optimization activities	20
Lower gross margin from lower volumes due to attrition, weather and customer mix of $42 million and higher supply costs of $5.50 per MWh, or $41 million, partially offset by higher revenue of $4 per MWh, or $30 million	(53)
Lower gross margin due to a 15% decrease in average realized pricing primarily at Midwest Generation, partially offset by increased volumes due to dark spread expansion in 2021 and planned outages in 2020	(14)
Lower gross margin due to a 20% decrease in New England capacity prices and a 5% decrease in New York capacity volumes, partially offset by a 17% increase in New York realized capacity prices	(7)
Other	5
Increase in economic gross margin	$ 853
Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges	2,726
Increase in contract amortization	(23)
Increase in depreciation and amortization	(141)
Increase in gross margin	**$ 3,415**

West/Services/Other

	(In millions)
Higher gross margin due to Winter Storm Uri , driven by optimization during volatility in gas pricing	$ 13
The following explanations exclude the impact of Winter Storm Uri:	
Higher gross margin due to increased volumes from the acquisition of Direct Energy in January 2021	304
Lower gross margin primarily at Cottonwood driven by an 84% increase in fuel cost while realized power prices remained constant	(41)
Lower gross margin from generation outage insurance proceeds received in 2020 for forced outages in 2019	(30)
Lower gross margin primarily due to a prior year MISO uplift payments resulting from out-of-market dispatch during Hurricane Laura	(30)
Lower gross margin from market optimization activities	(4)
Other	4
Increase in economic gross margin	$ 216
Increase in mark-to-market for economic hedges primarily due to net unrealized gains/losses on open positions related to economic hedges	155
Increase in contract amortization	(15)
Increase in depreciation and amortization	(37)
Increase in gross margin	**$ 319**

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 $4.0 billion during the nine months ended September 30, 2021, compared to the same period in 2020.

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

	Nine months ended September 30, 2021				
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Eliminations**	**Total**
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges	$ —	$ (20)	$ (2)	$ (2)	$ (24)
Reversal of acquired (gain) positions related to economic hedges	—	(6)	—	—	(6)
Net unrealized (losses) on open positions related to economic hedges	(5)	(27)	(58)	21	(69)
Total mark-to-market (losses) in operating revenues	$ (5)	$ (53)	$ (60)	$ 19	$ (99)
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges	$ (36)	$ —	$ —	$ 2	$ (34)
Reversal of acquired loss/(gain) positions related to economic hedges	20	202	(10)	—	212
Net unrealized gains on open positions related to economic hedges	1,088	2,647	230	(21)	3,944
Total mark-to-market gains in operating costs and expenses	$ 1,072	$ 2,849	$ 220	$ (19)	$ 4,122

	Nine months ended September 30, 2020				
(In millions)	**Texas**	**East**	**West/Services/ Other**	**Eliminations**	**Total**
Mark-to-market results in operating revenues					
Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges	$ 1	$ 29	$ (4)	$ 3	$ 29
Net unrealized gains on open positions related to economic hedges	—	34	10	5	49
Total mark-to-market gains in operating revenues	$ 1	$ 63	$ 6	$ 8	$ 78
Mark-to-market results in operating costs and expenses					
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	$ (92)	$ 5	$ (1)	$ (3)	$ (91)
Reversal of acquired loss positions related to economic hedges	1	1	—	—	2
Net unrealized gains on open positions related to economic hedges	28	1	—	(5)	24
Total mark-to-market (losses)/gains in operating costs and expenses	$ (63)	$ 7	$ (1)	$ (8)	$ (65)

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 nine months ended September 30, 2021, the $99 million loss in operating revenues from economic hedge positions was driven by a decrease in the value of open positions as a result of increases in Northeast and West/Other power prices as well as the reversal of previously recognized unrealized gains on contracts that settled during the period. The $4.1 billion gain in operating costs and expenses from economic hedge positions was driven primarily by an increase in the value of open positions as a result of increases in natural gas and power prices across all segments as well as the reversal of acquired contracts that settled during the period.

For the nine months ended September 30, 2020, the $78 million gain in operating revenues from economic hedge positions was driven by an increase in the value of open positions as a result of decreases in New York capacity and power prices as well as the reversal of previously recognized unrealized losses on contracts that settled during the period. The $65 million loss in operating costs and expenses from economic hedge positions was driven primarily by the reversal of previously recognized unrealized gains on contracts that settled during the period, partially offset by an increase in the value of open positions as a result of increases in ERCOT power prices.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the nine months ended September 30, 2021 and 2020. The realized and unrealized financial and physical trading results are included in operating revenue. The Company's trading activities are subject to limits based on the Company's Risk Management Policy.

	Nine months ended September 30,	
(In millions)	**2021**	**2020**
Trading gains		
Realized	$ 99	$ 26
Unrealized	2	5
Total trading gains	$ 101	$ 31

Operations and Maintenance Expense

Operations and maintenance expense are comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Corporate	Eliminations	Total
Nine months ended September 30, 2021	$ 524	$ 346	$ 168	$ 2	$ (4)	$ 1,036
Nine months ended September 30, 2020	480	276	79	6	(4)	837

Operations and maintenance expense increased by $199 million for the nine months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to the acquisition of Direct Energy in January 2021	$ 186
Increase in variable operation and maintenance expense at the PJM coal facilities associated with increased generation in 2021	16
Increase in major maintenance primarily due to the duration and scope of planned and forced outages in Texas during 2021	15
Increase due to spare parts inventory reserves driven by announced retirements of certain PJM coal assets	13
Increase driven by higher maintenance resulting from the impacts of Winter Storm Uri	2
Decrease driven by lower retail operations costs	(18)
Decrease in lease expense primarily driven by the buyout of the Midwest Generation lease in 2020	(16)
Other	1
Increase in operations and maintenance expense	$ 199

Other Cost of Operations

Other Cost of operations are comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Total
Nine months ended September 30, 2021	$ 144	$ 102	$ 13	$ 259
Nine months ended September 30, 2020	134	70	16	220

Other cost of operations increased by $39 million for the nine months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to the acquisition of Direct Energy in January 2021	$ 63
Decrease primarily due to ARO expense in 2020 at Jewett Mine and Joliet as a result of regulatory requirements	(25)
Other	1
Increase in other cost of operations	$ 39

Depreciation and Amortization

Depreciation and amortization expenses are comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Corporate	Total
Nine months ended September 30, 2021	$ 245	$ 238	$ 65	$ 21	$ 569
Nine months ended September 30, 2020	167	97	28	26	318

Depreciation and amortization increased by $251 million for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to amortization of acquired intangibles in connection with the acquisition of Direct Energy in January 2021.

Impairment Losses

Impairment losses of $306 million were recorded during the nine months ended September 30, 2021, related to the decline in capacity prices and the planned retirement of a significant portion of the PJM coal fleet, as further discussed in Note 8, *Impairments*.

Selling, General and Administrative Costs

Selling, general and administrative costs comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Corporate	Eliminations	Total
Nine months ended September 30, 2021	$ 435	$ 374	$ 128	$ 37	$ (1)	$ 973
Nine months ended September 30, 2020	347	186	40	20	(1)	592

Selling, general and administrative costs increased by $381 million for the nine months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to the acquisition of Direct Energy in January 2021	$ 338
Increase due to Winter Storm Uri, including charitable giving, legal and other costs of $17 million and ERCOT default charges of $12 million	29
Increase due to higher consulting and insurance costs	16
Increase due to higher medical expenses and a reduction of payroll tax benefits	8
Decrease due to the favorable resolution of a legal matter	(15)
Other	5
Increase in selling, general and administrative costs	$ 381

Provision for Credit Losses

Provision for credit losses are comprised of the following:

(In millions)	Texas	East	West/Services/ Other	Total
Nine months ended September 30, 2021	$ 700	$ 7	$ 8	$ 715
Nine months ended September 30, 2020	69	4	1	74

Provision for credit losses increased by $641 million for the nine months ended September 30, 2021, compared to the same period in 2020, due to the following:

	(In millions)
Increase due to Winter Storm Uri, including: Increase of $403 million related to bilateral financial hedging risk Increase of $152 million related to counterparty credit risk Increase of $83 million related to ERCOT default shortfall payments	$ 638
Increase due to the acquisition of Direct Energy in January 2021, partially offset by improved collections in the legacy brands	3
Increase in provision for credit losses	$ 641

Acquisition-Related Transaction and Integration Costs

Acquisition-related transaction and integration costs were $81 million for the nine months ended September 30, 2021. Acquisition-related transaction costs increased $13 million when compared to the same period in 2020, primarily related to the closing of the Direct Energy acquisition. Integration costs increased by $55 million when compared to the same period in 2020, which were primarily related to severance and consulting services for the Direct Energy acquisition.

Gain on Sale of Assets

The gain on sale of assets of $17 million was recorded for the nine months ended September 30, 2021 due to the sale of Agua Caliente in February 2021, compared to the gain on the sale of assets of $6 million for the nine months ended September 30, 2020 related to the sale of land and investments in January 2020.

Equity in Earnings of Unconsolidated Affiliates

Equity in earnings of unconsolidated affiliates was $14 million lower for the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020, primarily due to the sale of the Agua Caliente solar project and unfavorable weather resulting in decreased earnings at Ivanpah in 2021, partially offset by higher earnings at Watson Cogeneration due to a favorable settlement in 2021.

Impairment Losses on Investments

Impairment losses on investments was $18 million during the nine months ended September 30, 2020 related to the impairment of Petra Nova Parish Holdings, as further discussed in Note 8*, Impairments*.

Other Income, Net

Other income decreased by $10 million for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to reduced reimbursements received in 2021 of $10 million and dividends received from cost method investments in 2020 of $5 million, partially offset by increased pension income in 2021 of $7 million due to a decrease in discount rates.

Loss on debt extinguishment, Net

Loss on debt extinguishment of $57 million was recorded for the nine months ended September 30, 2021, in connection with the redemption of senior notes, as further discussed in Note 9*, Long-term Debt and Finance Leases.*

Interest Expense

Interest expense increased by $82 million for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to financings entered into in connection with the Direct Energy acquisition.

Income Tax Expense

For the nine months ended September 30, 2021, income tax expense of $840 million was recorded on pre-tax income of $3.5 billion. For the same period in 2020, income tax expense of $216 million was recorded on a pre-tax income of $899 million. The effective tax rates were 24.3% and 24.0% for the nine months ended September 30, 2021 and 2020, respectively.

For the nine months ended September 30, 2021, NRG's overall effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense partially offset by one-time tax benefits, as a result of the acquisition of Direct Energy, on revaluation of state deferred tax assets, NOLs and valuation allowance. For the same period in 2020, NRG's overall effective tax rate was higher that the statutory rate of 21% due to state tax expense, partially offset by an excess tax benefit related to share-based compensation.

Liquidity and Capital Resources

Liquidity Position

As of September 30, 2021 and December 31, 2020, NRG's total liquidity, excluding funds deposited by counterparties, of approximately $3.3 billion and $7.0 billion, respectively, was comprised of the following:

(In millions)	September 30, 2021	December 31, 2020
Cash and cash equivalents	$ 259	$ 3,905
Restricted cash - operating	9	3
Restricted cash - reserves[a]	5	3
Total	273	3,911
Total availability under Revolving Credit Facility and collective collateral facilities[b]	3,041	3,129
Total liquidity, excluding funds deposited by counterparties	$ 3,314	$ 7,040

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

(b) Total capacity of Revolving Credit Facility and collective collateral facilities was $6.0 billion and $4.0 billion as of September 30, 2021 and December 31, 2020, respectively

For the nine months ended September 30, 2021, total liquidity, excluding funds deposited by counterparties, decreased by $3.7 billion. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading *Cash Flow Discussion*. Cash and cash equivalents at September 30, 2021 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.

On March 17, 2021, following Winter Storm Uri, Standard & Poor's placed NRG's issuer credit rating of BB+ on CreditWatch with negative implications. On May 12, 2021, Standard & Poor's affirmed NRG's issuer credit rating of BB+ with a stable outlook. On March 19, 2021, Moody's changed NRG's rating outlook to stable from positive. At the same time, Moody's affirmed NRG's corporate family rating of Ba1.

Liquidity

The principal sources of liquidity for NRG's future operating and maintenance capital expenditures are expected to be derived from cash on hand, cash flows from operations, and financing arrangements, as described in Note 9, *Long-term Debt and Finance Leases*, to this Form 10-Q. The Company's financing arrangements consist mainly of the Senior Notes, Convertible Senior Notes, Senior Secured First Lien Notes, Revolving Credit Facility, and tax-exempt bonds.

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

Direct Energy Acquisition

On January 5, 2021, the Company acquired Direct Energy, a North American subsidiary of Centrica. Direct Energy is a leading retail provider of electricity, natural gas, and home and business energy related products and services in North America, with operations in all 50 U.S. states and 8 Canadian provinces.

The Company paid an aggregate purchase price of $3.625 billion in cash and an initial purchase price adjustment of $77 million. The Company funded the purchase price using a combination of $715 million cash on hand, $166 million from a draw on its Revolving Credit Facility (of which $107 million was used to fund acquisition costs and financing fees that are not included in the aggregate purchase price above), as well as approximately $2.9 billion in secured and unsecured corporate debt issued in December 2020. The purchase price adjustment resulted in a reduction of $3 million, which is in negotiation with Centrica. The Company expects to receive this payment from Centrica in 2021.

Collateral Facility Increases

The following table presents increases to the Company's collective collateral facilities in connection with the Direct Energy acquisition.

	(In millions)
Available on Acquisition Closing Date	
Revolving Credit Facility commitment increase	$ 802
Revolving Credit Facility new tranche	273
Facility agreement in connection with the sale of pre-capitalized trust securities	874
Available as of December 31, 2020	
Credit default swap facility	150
Revolving accounts receivable financing facility	750
Repurchase facility	75
Bilateral letter of credit facilities	475
Total Increases to Liquidity and Collateral Facilities	$ 3,399

Planned Debt Reduction

In light of the impact of Winter Storm Uri, the Company's deleveraging program will extend to 2023. The Company remains committed to maintaining a strong balance sheet and continues to work closely with rating agencies to achieve investment grade credit ratings.

Financing Activities

On August 23, 2021, the Company issued $1.1 billion of aggregate principal amount at par of 3.875% senior notes due 2032 (the "2032 Senior Notes"). The 2032 Senior Notes are senior unsecured obligations of NRG and are guaranteed by certain of its subsidiaries. The 2032 Senior Notes were issued under NRG's Sustainability-Linked Bond Framework, which sets out certain sustainability targets, including reducing greenhouse gas emissions. Failure to meet such sustainability targets will result in a 25 basis point increase to the interest rate payable on the 2032 Senior Notes from and including August 15, 2026.

On August 24, 2021, the Company redeemed $1,355 million in aggregate principal of its Senior Notes for $1,425 million using the proceeds of the 2032 Senior Notes and cash on hand, resulting in total deleveraging of $255 million. In connection with the redemptions, a $57 million loss on debt extinguishment was recorded, which included the write-off of previously deferred financing costs of $9 million, during the nine months ended September 30, 2021. As a result of the financing activities, annualized interest savings are expected to be approximately $53 million. The Company redeemed an additional $500 million of its 6.625% Senior Notes due 2027 through November 4, 2021.

Receivables Securitization Facilities

On July 26, 2021, NRG Receivables LLC, wholly-owned indirect subsidiary of the Company, renewed its existing Receivables Facility to, among others, (i) increase the facility size to $800 million, (ii) extend the maturity date until July 26, 2022, (iii) make certain adjustments to the pool of receivables through the Receivables Facility and certain related covenants, and (iv) provide for revised language relating to interest determination based on SOFR in case of a LIBOR cessation or the occurrence of certain other trigger events. As of September 30, 2021, there were no outstanding borrowings and there were $400 million in letters of credit issued under the Receivables Facility.

On July 26, 2021, the Company renewed its existing Repurchase Facility to, among other things, (i) extend the maturity date to July 26, 2022 and (ii) provide for revised language relating to interest determination based on SOFR in case of a LIBOR cessation or the occurrence of certain other trigger events.

Sale of Agua Caliente

On February 3, 2021, the Company closed on the sale of its 35% ownership in the Agua Caliente solar project to Clearway Energy, Inc. for $202 million. NRG recognized a gain on the sale of $17 million, including cash disposed of $7 million.

Sale of 4.8 GW of Fossil Generation Assets

On February 28, 2021, the Company entered into a definitive purchase agreement with Generation Bridge, an affiliate of ArcLight Capital Partners, to sell approximately 4,850 MW of fossil generating assets from its East and West regions of operations for total proceeds of $760 million, subject to standard purchase price adjustments and certain other indemnifications. The purchase price adjustments will include a working capital deduction for cash flows generated of approximately $11 million per month from the beginning of the year until the closing of the transaction, in lieu of cash flows generated during the year. As part of the transaction, NRG is entering into a tolling agreement for its 866 MW Arthur Kill plant in New York City through April 2025.

The transaction is expected to close by the end of 2021 and is subject to various closing conditions, approvals and consents, including approval from the NYPSC. The transaction has received FERC approval and approval under the Hart-Scott-Rodino Act.

Pension Plan Contributions

The American Rescue Plan Act ("ARPA") was enacted on March 11, 2021 to provide economic relief related to the COVID-19 pandemic. ARPA provides pension funding relief for single employer plans, among other provisions. As a result, NRG has reduced its previously planned cash contribution for 2021 by approximately $23 million. NRG's pension and postretirement benefit plans are further described in Note 16, *Benefit Plans and Other Postretirement Benefits*, of Part IV, Item 15 of the Company's 2020 Form 10-K.

CARES Act

On March 27, 2020, the U.S. government enacted the CARES Act, which provides, among other things: (i) the option to defer payments of certain 2019 employer payroll taxes incurred after the date of enactment; and (ii) allows NOLs from tax years 2018, 2019 and 2020 to be carried back five years. The total benefit to the Company due to the CARES Act was $35 million. Of this amount, $13 million will be payable to social security in 2021 and $13 million will be payable in 2022.

Market Operations

The Company's market operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) margin and collateral required to participate in physical markets and commodity exchanges; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of September 30, 2021, the Company had total cash collateral outstanding of $21 million and $3.0 billion outstanding in letters of credit to third parties primarily to support its market activities. As of September 30, 2021, total funds deposited by counterparties were $1.7 billion in cash and $401 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 depend on the Company's credit ratings and general perception of its creditworthiness.

First Lien Structure

NRG has granted first liens to certain counterparties on a substantial portion of the Company's assets, subject to various exclusions including NRG's assets that have project-level financing and the assets of certain non-guarantor subsidiaries, 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 first lien program does not limit the volume that can be hedged, or the value of underlying out-of-the-money positions. The first lien program also does not require NRG to post collateral above any threshold amount of exposure. 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 September 30, 2021, all hedges under the first liens were out-of-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MW hedged against the Company's coal and nuclear assets and as a percentage relative to the Company's coal and nuclear capacity under the first lien structure as of September 30, 2021:

Equivalent Net Sales Secured by First Lien Structure[(a)]	**2021**	**2022**	**2023**
In MW	597	751	745
As a percentage of total net coal and nuclear capacity[(b)]	15%	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 with Midwest Generation and NRG's assets that have project level financing

Capital Expenditures

The following tables and descriptions summarize the Company's capital expenditures for maintenance, environmental and growth investments for the nine months ended September 30, 2021, and the estimated capital expenditures forecast for the remainder of 2021.

(In millions)	Maintenance	Environmental	Growth Investments[(a)]	Total
Texas	$ (105)	$ (1)	$ (20)	$ (126)
East	(19)	(1)	(23)	(43)
West/Services/Other	(15)	—	—	(15)
Corporate	(3)	—	(32)	(35)
Total cash capital expenditures for the nine months ended September 30, 2021	(142)	(2)	(75)	(219)
Investments	—	—	(28)	(28)
Total capital expenditures and investments	(142)	(2)	(103)	(247)
Estimated capital expenditures and investments for the remainder of 2021	$ (63)	$ (6)	$ (70)	$ (139)

(a) Includes other investments, acquisitions, digital NRG and integration

Growth investments in East for the nine months ended September 30, 2021 include the Astoria generating facility, for which the Company had proposed to replace the existing units with a single, new state-of-the-art Simple Cycle Combustion Turbine having a total generating capacity of 437 MW. On October 27, 2021, the New York State Department of Environmental Conservation denied the Company's application for an air permit and we are currently assessing our response to this denial. To date, the Company has spent approximately $38 million on the Astoria project. Additionally, included in Investments are expenditures for Encina site improvements classified as ARO payments. Demolition is underway and is expected to be completed in the first half of 2022. The Company expects to begin marketing the site in 2022.

Environmental Capital Expenditures

NRG estimates that environmental capital expenditures from 2021 through 2025 required to comply with environmental laws will be approximately $55 million. The increase of $33 million from the previous quarter is primarily due to the cost of complying with ELG at our coal units in Texas.

Common Stock Dividends

During the first quarter of 2021, NRG increased the annual dividend to $1.30 from $1.20 per share and expects to target an annual dividend growth rate of 7-9% per share in subsequent years. A quarterly dividend of $0.325 per share was paid on the Company's common stock during the three months ended September 30, 2021. On October 15, 2021, NRG declared a quarterly dividend on the Company's common stock of $0.325 per share, payable on November 15, 2021 to stockholders of record as of November 1, 2021. Beginning in the first quarter of 2022, NRG will increase the annual dividend by 8% to $1.40 per share.

Cash Flow Discussion

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

	Nine months ended September 30,		
(In millions)	2021	2020	Change
Net Cash Provided by Operating Activities	$ 1,855	$ 1,386	$ 469
Net Cash Used by Investing Activities	(3,585)	(484)	(3,101)
Net Cash Used by Financing Activities	(177)	(567)	390

Net Cash Provided by Operating Activities

Changes to net cash provided/(used) by operating activities were driven by:

		(In millions)
Changes in cash collateral in support of risk management activities due to change in commodity prices	$	1,874
Increase in working capital related to accounts receivable primarily driven by milder weather in 2020, the impact of Winter Storm Uri and additional early settlement of capacity obligations in 2021		(927)
Decrease in operating income adjusted for other non-cash items		(698)
Increase in working capital primarily due to higher deferred revenues from the impact of Winter Storm Uri and increased accruals for renewable energy credits as a result of the acquisition of Direct Energy		421
Decrease in working capital primarily due to increases in purchases of renewable energy credits due to an increased customer count as a result of the acquisition of Direct Energy		(301)
Increase in working capital related to accounts payable primarily driven by increases in gas purchases and bilateral physical settlements driven by price and volume in ERCOT		175
Decrease in working capital due to replenishing natural gas inventory at significantly higher prices		(80)
Increase in other working capital		5
	$	469

Net Cash Used by Investing Activities

Changes to net cash (used)/provided by investing activities were driven by:

		(In millions)
Increase in cash paid for acquisitions primarily for Direct Energy	$	(3,257)
Increase in proceeds from sale of assets primarily due to sale of Agua Caliente		183
Increase in capital expenditures		(52)
Increase in sales of emissions allowances, net of purchases		21
Other		4
	$	(3,101)

Net Cash Used by Financing Activities

Changes to net cash (used)/provided by financing activities were driven by:

		(In millions)
Increase in payments of long-term debt	$	(1,298)
Increase in proceeds from issuance of long-term debt		1,041
Increase in net receipts from settlement of acquired derivatives		402
Decrease in payments for share repurchase activity		220
Increase in proceeds from Revolving Credit Facility and Receivables Securitization Facilities		83
Increase in payments of debt extinguishment costs and deferred issuance costs		(42)
Increase in payments of dividends to common stockholders		(18)
Other		2
	$	390

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

For the nine months ended September 30, 2021, the Company had domestic pre-tax book income of $3.4 billion and foreign pre-tax book income of $131 million. As of December 31, 2020, the Company had cumulative domestic Federal NOL carryforwards of $10.1 billion, of which $2.3 billion were generated prior to Tax Cuts and Jobs Act and will begin expiring in 2031, and cumulative state NOL carryforwards of $5.4 billion for financial statement purposes. NRG also has cumulative foreign NOL carryforwards of $347 million, which do not have an expiration date. In addition to the above NOLs, NRG has a $14 million indefinite carryforward for interest deductions, as well as $384 million of tax credits to be utilized in future years. As a result of the Company's tax position, and based on current forecasts, NRG anticipates income tax payments, primarily to state and foreign jurisdictions, of up to $71 million in 2021.

As of September 30, 2021, the Company has $25 million of tax-effected uncertain federal and state tax benefits, for which the Company has recorded a non-current tax liability (inclusive of accrued interest) until final resolution is reached with the related taxing authority.

The Company is no longer subject to U.S. federal income tax examinations for years prior to 2017. With few exceptions, state and local income tax examinations are no longer open for years prior to 2012.

Deferred tax assets and valuation allowance

Net deferred tax balance — As of September 30, 2021 and December 31, 2020, NRG recorded a net deferred tax asset, excluding valuation allowance, of $2.2 billion and $3.3 billion, respectively. The Company believes certain state net operating losses may not be realizable under the more-likely-than-not measurement and as such, a valuation allowance was recorded as of September 30, 2021 as discussed below.

NOL Carryforwards — As of September 30, 2021, the Company had a tax-effected cumulative U.S. NOLs consisting of carryforwards for federal and state income tax purposes of $2.1 billion and $458 million, respectively. The Company estimates it will need to generate future taxable income to fully realize the net federal deferred tax asset before the expiration of certain carryforwards commences in 2031. In addition, NRG has tax-effected cumulative foreign NOL carryforwards of $107 million with no expiration date.

Valuation Allowance — As of September 30, 2021 and December 31, 2020, the Company's tax-effected valuation allowance was $259 million and $266 million, respectively, consisting of state NOL carryforwards and foreign NOL carryforwards. The valuation allowance was recorded based on the assessment of cumulative and forecasted pre-tax book earnings and the future reversal of existing taxable temporary differences.

Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

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

The Company disclosed its Guarantees in Note 28, *Guarantees,* to the Company's 2020 Form 10-K. As of September 30, 2021, NRG and its consolidated subsidiaries were contingently obligated for a total of $3.6 billion under letters of credit and surety bonds, compared to $1.2 billion as of December 31, 2020. The increase is primarily due to the acquisition of Direct Energy in January 2021. Most of these letters of credit and surety bonds are issued in support of the Company's obligations to perform under commodity agreements and obligations associated with future closure and maintenance of ash sites, as well as for financing or other arrangements. A majority of these letters of credit and surety bonds expire within one year of issuance, and it is typical for the Company to renew them on similar terms.

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 September 30, 2021, NRG has investments in energy and energy-related entities that are accounted for under the equity method of accounting. NRG's investment in Ivanpah is a variable interest entity for which NRG is not the primary beneficiary. See also Note 10, *Investments Accounted for Using the Equity Method and Variable Interest Entities, or VIEs*.

NRG's pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $556 million as of September 30, 2021. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Note 15, *Investments Accounted for by the Equity Method and Variable Interest Entities,* to the Company's 2020 Form 10-K.

Contractual Obligations and Market Commitments

NRG has a variety of contractual obligations and other market commitments that represent prospective cash requirements in addition to the Company's capital expenditure programs, as disclosed in the Company's 2020 Form 10-K. See also Note 9, *Long-term Debt and Finance Leases*, and Note 16, *Commitments and Contingencies*, to this Form 10-Q for a discussion of new commitments and contingencies that also include contractual obligations and market commitments that occurred during the three and nine months ended September 30, 2021.

Guarantor Financial Information

As of September 30, 2021, the Company's outstanding registered senior notes consisted of $875 million of the 2027 Senior Notes and $821 million of the 2028 Senior Notes as shown in Note 9, *Long-term Debt and Finance Leases*. These Senior Notes are guaranteed by certain of NRG's current and future 100% owned domestic subsidiaries, or guarantor subsidiaries (the "Guarantors"). See Exhibit 22.1 for a listing of the Guarantors. These guarantees are both joint and several.

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 Guarantors to transfer funds to NRG. Other subsidiaries of the Company do not guarantee the registered debt securities of either NRG Energy, Inc or the Guarantors (such subsidiaries are referred to as the "Non-Guarantors"). The Non-Guarantors include all of NRG's foreign subsidiaries and certain domestic subsidiaries.

The tables below present summarized financial information of NRG Energy, Inc. and the Guarantors in accordance with Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position of NRG Energy, Inc. and the Guarantors in accordance with U.S. GAAP.

The following table presents the summarized statement of operations:

(In millions)	**Nine months ended September 30, 2021[a]**
Operating revenues	$ 17,675
Operating income	4,144
Total other expense	(373)
Income from Continuing Operations	3,771
Net Income	2,963

(a) Intercompany transactions with Non-Guarantors include operating revenue of $77 million, cost of operations of $(191) million and selling, general and administrative of $76 million

The following table presents the summarized balance sheet information:

(In millions)	**September 30, 2021**
Current assets[a]	$ 14,628
Property, plant and equipment, net	1,353
Non-current assets	12,229
Current liabilities[a]	12,865
Non-current liabilities	11,386

(a) Includes intercompany receivables of $461 million and intercompany payables of $73 million due from Non-Guarantors

Fair Value of Derivative Instruments

NRG may enter into power purchase and sales contracts, fuel purchase contracts and other energy-related financial instruments to mitigate variability in earnings due to fluctuations in spot market prices and to hedge fuel requirements at power plants or retail load obligations. In addition, in order to mitigate foreign exchange rate risk associated with the purchase of USD denominated natural gas for the Company's Canadian business, NRG enters into foreign exchange contract agreements.

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

The tables below disclose the activities that include both exchange and non-exchange traded contracts accounted for at fair value in accordance with ASC 820, *Fair Value Measurements and Disclosures*, or ASC 820. Specifically, these tables disaggregate realized and unrealized changes in fair value; disaggregate estimated fair values at September 30, 2021, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at September 30, 2021. For a full discussion of the Company's valuation methodology of its contracts, see *Derivative Fair Value Measurements* in Note 5, *Fair Value of Financial Instruments*.

Derivative Activity (Losses)/Gains	**(In millions)**
Fair Value of Contracts as of December 31, 2020	$ (63)
Contracts realized or otherwise settled during the period	128
Direct contracts acquired during the period	(283)
Changes in fair value	3,896
Fair Value of Contracts as of September 30, 2021	$ 3,678

(In millions)	Fair Value of Contracts as of September 30, 2021				
	Maturity				
Fair value hierarchy Gains	**1 Year or Less**	**Greater than 1 Year to 3 Years**	**Greater than 3 Years to 5 Years**	**Greater than 5 Years**	**Total Fair Value**
Level 1	$ 459	$ 287	$ 32	$ 7	$ 785
Level 2	1,830	628	92	32	2,582
Level 3	207	46	14	44	311
Total	$ 2,496	$ 961	$ 138	$ 83	$ 3,678

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or posted on the Company's derivative assets or liabilities are recorded on a separate line item on the balance sheet. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company's portfolio. As discussed in Item 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 September 30, 2021, NRG's net derivative asset was $3.7 billion, an increase to total fair value of $3.7 billion as compared to December 31, 2020. This increase was primarily driven by gains in fair value and roll-off of trades that settled during the period, partially offset by Direct Energy contracts acquired during the period.

Based on a sensitivity analysis using simplified assumptions, the impact of a $0.50 per MMBtu increase in natural gas prices across the term of the derivative contracts would result in an increase of approximately $1.2 billion in the net value of derivatives as of September 30, 2021.

The impact of a $0.50 per MMBtu decrease in natural gas prices across the term of derivative contracts would result in a decrease of approximately $1.3 billion in the net value of derivatives as of September 30, 2021.

Critical Accounting Policies and Estimates

NRG's discussion and analysis of the financial condition and results of operations are based upon the condensed consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and the fair value of certain assets and liabilities. These judgments 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 critical accounting policies as those that are the most pervasive and important to the portrayal of the Company's financial position and results of operations, and require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain. 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's significant accounting policies are outlined in Note 2, *Summary of Significant Accounting Policies*, of this Form 10-Q, and in Note 2, *Summary of Significant Accounting Policies*, under Part IV, Item 15 of the Company's 2020 Form 10-K. The Company's critical accounting estimates are described in Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, in the Company's 2020 Form 10-K. There have been no material changes to the Company's critical accounting policies and estimates since the 2020 Form 10-K.

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 existing or forecasted financial or commodity transactions. The types of market risks the Company is exposed to are commodity price risk, liquidity risk, credit risk, interest rate 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 2020 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, gas transportation and storage assets, load obligations and bilateral physical and financial transactions, based on historical and forward values for factors such as customer demand, weather, commodity availability and commodity prices. The Company's VaR model is based on a one-day holding period at a 95% confidence interval for the forward 36 months, not including the spot month. The VaR model is not a complete picture of all risks that may affect the Company's results. Certain events such as counterparty defaults, regulatory changes, and extreme weather and prices that deviate significantly from historically observed values are not reflected in the model.

The following table summarizes average, maximum and minimum VaR for NRG's commodity portfolio, calculated using the VaR model for the three and nine months ending September 30, 2021 and 2020:

(In millions)	2021	2020
VaR as of September 30, [(a)]	$ 41	$ 38
Three months ended September 30,		
Average	$ 43	$ 31
Maximum	50	40
Minimum	38	25
Nine months ended September 30,		
Average[(b)]	$ 36	$ 28
Maximum[(b)]	50	47
Minimum[(b)]	25	22

(a) Calculation includes entire NRG portfolio as of September 30, 2021

(b) Calculation is based on NRG generation assets and load obligations excluding the acquisition of Direct Energy assets and load obligations in the first quarter of 2021

In order to provide additional information, the Company also uses VaR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VaR for the derivative financial instruments calculated using the diversified VaR model for the entire term of these instruments entered into for both asset management and trading, was $282 million, as of September 30, 2021, primarily driven by asset-backed and hedging transactions. The increase in the VaR for derivative financial instruments was primarily due to the acquisition of Direct Energy.

Liquidity Risk

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

Based on a sensitivity analysis for power and gas positions under marginable contracts as of September 30, 2021, a $0.50 per MMBtu decrease in natural gas prices across the term of the marginable contracts would cause an increase in margin collateral posted of approximately $690 million and a 1.00 MMBtu/MWh decrease in heat rates for heat rate positions would result in an increase in margin collateral posted of approximately $355 million. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of September 30, 2021.

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 5, *Fair Value of Financial Instruments*, to this Form 10-Q for discussions regarding counterparty credit risk and retail customer credit risk, and Note 7, *Accounting for Derivative Instruments and Hedging Activities*, to this Form 10-Q for discussion regarding credit risk contingent features.

Interest Rate Risk

As of September 30, 2021, the fair value and related carrying value of the Company's debt was $8.9 billion and $8.5 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 as of September 30, 2021 by $715 million.

Currency Exchange Risk

NRG is subject to transactional exchange rate risk from transactions with customers in countries outside of the United States, primarily within Canada, as well as from intercompany transactions between affiliates. Transactional exchange rate risk arises from the purchase and sale of goods and services in currencies other than our functional currency or the functional currency of an applicable subsidiary. NRG hedges a portion of its forecasted currency transactions with foreign exchange forward contracts. As of September 30, 2021, NRG is exposed to changes in foreign currency associated with the purchase of U.S. dollar denominated natural gas for its Canadian business and entered into foreign exchange contracts with notional amount of $218 million.

The Company is subject to translation exchange rate risk related to the translation of the financial statements of its foreign operations into U.S. dollars. Costs incurred and sales recorded by subsidiaries operating outside of the United States are translated into U.S. dollars using exchange rates effective during the respective period. As a result, the Company is exposed to movements in the exchange rates of various currencies against the U.S. dollar, primarily the Canadian and Australian dollars. A hypothetical 10% appreciation in major currencies relative to the U.S. dollar as of September 30, 2021 would have resulted in an increase of $10 million to net income within the Consolidated Statement of Operations.

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 September 30, 2021 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 September 30, 2021, see Note 16, *Commitments and Contingencies*, to this Form 10-Q.

ITEM 1A — RISK FACTORS

During the nine months ended September 30, 2021, there were no material changes to the Risk Factors disclosed in Part I, Item 1A, *Risk Factors,* of the Company's 2020 Form 10-K.

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

During the quarter ended September 30, 2021, no purchases of NRG's common stock were made by or on behalf of NRG or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act).

ITEM 3 — DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4 — MINE SAFETY DISCLOSURES

There have been no events that are required to be reported under this Item.

ITEM 5 — OTHER INFORMATION

None.

ITEM 6 — EXHIBITS

Number	Description	Method of Filing
4.1	Second Supplemental Indenture, dated August 23, 2021, among NRG Energy, Inc., the guarantors named therein and Deutsche Bank Trust Company Americas, as trustee.	Incorporated herein by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K, filed on August 23, 2021.
4.2	Form of 3.875% Senior Notes due 2032.	Incorporated herein by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K, filed on August 23, 2021.
22.1	List of Guarantor Subsidiaries	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 Alberto Fornaro.	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	Inline XBRL Instance Document.	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101 SCH	Inline XBRL Taxonomy Extension Schema.	Filed herewith.
101 CAL	Inline XBRL Taxonomy Extension Calculation Linkbase.	Filed herewith.
101 DEF	Inline XBRL Taxonomy Extension Definition Linkbase.	Filed herewith.
101 LAB	Inline XBRL Taxonomy Extension Label Linkbase.	Filed herewith.
101 PRE	Inline XBRL Taxonomy Extension Presentation Linkbase.	Filed herewith.
104	Cover Page Interactive Data File (the cover page interactive data file does not appear in Exhibit 104 because it's Inline XBRL tags are embedded within the Inline XBRL document).	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/ ALBERTO FORNARO

Alberto Fornaro
Chief Financial Officer
(Principal Financial Officer)

/s/ DAVID CALLEN

David Callen
Chief Accounting Officer
(Principal Accounting Officer)

Date: November 4, 2021