# 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: June 30, 2022**

☐ **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 July 31, 2022, there were 235,147,142 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," "targets" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors, many of which are beyond NRG's control, 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. Forward-looking statements are not guarantees of future results. 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, 2021 and the following:

- Business uncertainties related to the integration of 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 variants thereof, 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;
- Cyber terrorism and cybersecurity risks, data breaches or the occurrence of a catastrophic loss and the possibility that NRG may not have sufficient insurance to cover losses resulting from such hazards or the inability of NRG's insurers to provide coverage;
- 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;
- 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.

In addition, unlisted factors may present significant additional obstacles to the realization of forward-looking statements. 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 except as otherwise required by applicable laws. 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:

| | |
|---|---|
| 2021 Form 10-K | NRG's Annual Report on Form 10-K for the year ended December 31, 2021 |
| 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 |
| Company | NRG Energy, Inc. |
| Convertible Senior Notes | As of June 30, 2022, consists of NRG's $575 million unsecured 2.75% Convertible Senior Notes due 2048 |
| Cottonwood | Cottonwood Generating Station, a 1,177 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 |
| Dth | Dekatherms |
| Economic gross margin | Sum of retail revenue, energy revenue, capacity revenue and other revenue, less cost of fuels and purchased energy 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 |
| LIBOR | London Inter-Bank Offered Rate |
| LSEs | Load Serving Entities |
| 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 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 |
| OCI/OCL | Other Comprehensive Income/(Loss) |
| 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 $1.0 billion accounts receivables securitization facility due 2023, which was amended on July 26, 2021 and July 26, 2022 |
| Receivables Securitization Facilities | Collectively, the Receivables Facility and the Repurchase Facility |

| | |
|---|---|
| Repurchase Facility | NRG's $150 million uncommitted repurchase facility related to the Receivables Facility due 2023, which was amended on July 26, 2021, February 9, 2022 and July 26, 2022 |
| 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 |
| RMR | Reliability Must-Run |
| 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 June 30, 2022, NRG's $4.6 billion outstanding unsecured senior notes consisting of $375 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 June 30, 2022, 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)

| (In millions, except for per share amounts) | Three months ended June 30, 2022 | Three months ended June 30, 2021 | Six months ended June 30, 2022 | Six months ended June 30, 2021 |
|---|---|---|---|---|
| **Revenue** | | | | |
| Revenue | $ 7,282 | $ 5,243 | $ 15,178 | $ 13,334 |
| **Operating Costs and Expenses** | | | | |
| Cost of operations (excluding depreciation and amortization shown below) | 5,887 | 2,948 | 10,817 | 9,805 |
| Depreciation and amortization | 157 | 53 | 340 | 370 |
| Impairment losses | 155 | 306 | 155 | 306 |
| Selling, general and administrative costs | 325 | 317 | 647 | 654 |
| Provision for credit losses | 26 | 40 | 51 | 651 |
| Acquisition-related transaction and integration costs | 10 | 22 | 18 | 64 |
| Total operating costs and expenses | 6,560 | 3,686 | 12,028 | 11,850 |
| Gain on sale of assets | 32 | — | 29 | 17 |
| **Operating Income** | 754 | 1,557 | 3,179 | 1,501 |
| **Other Income/(Expense)** | | | | |
| Equity in earnings/(losses) of unconsolidated affiliates | 4 | 14 | (11) | 8 |
| Other income, net | 12 | 12 | 12 | 34 |
| Interest expense | (105) | (125) | (208) | (252) |
| Total other expense | (89) | (99) | (207) | (210) |
| **Income Before Income Taxes** | 665 | 1,458 | 2,972 | 1,291 |
| Income tax expense | 152 | 380 | 723 | 295 |
| **Net Income** | $ 513 | $ 1,078 | $ 2,249 | $ 996 |
| **Income per Share** | | | | |
| Weighted average number of common shares outstanding — basic and diluted | 237 | 245 | 240 | 245 |
| **Income per Weighted Average Common Share —Basic and Diluted** | $ 2.16 | $ 4.40 | $ 9.37 | $ 4.07 |

See accompanying notes to condensed consolidated financial statements.

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **(In millions)** | **2022** | **2021** | **2022** | **2021** |
| **Net Income** | $ 513 | $ 1,078 | $ 2,249 | $ 996 |
| **Other Comprehensive (Loss)/Income** | | | | |
| Foreign currency translation adjustments | (22) | 2 | (13) | 5 |
| Defined benefit plans | 20 | 19 | 19 | 19 |
| Other comprehensive (loss)/income | (2) | 21 | 6 | 24 |
| **Comprehensive Income** | $ 511 | $ 1,099 | $ 2,255 | $ 1,020 |

See accompanying notes to condensed consolidated financial statements.

## NRG ENERGY, INC. AND SUBSIDIARIES
## CONDENSED CONSOLIDATED BALANCE SHEETS

| (In millions, except share data) | June 30, 2022 (Unaudited) | December 31, 2021 (Audited) |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 580 | $ 250 |
| Funds deposited by counterparties | 3,970 | 845 |
| Restricted cash | 44 | 15 |
| Accounts receivable, net | 3,862 | 3,245 |
| Uplift securitization proceeds receivable from ERCOT | — | 689 |
| Inventory | 604 | 498 |
| Derivative instruments | 11,323 | 4,613 |
| Cash collateral paid in support of energy risk management activities | 295 | 291 |
| Prepayments and other current assets | 470 | 395 |
| Total current assets | 21,148 | 10,841 |
| **Property, plant and equipment, net** | 1,598 | 1,688 |
| **Other Assets** | | |
| Equity investments in affiliates | 127 | 157 |
| Operating lease right-of-use assets, net | 237 | 271 |
| Goodwill | 1,657 | 1,795 |
| Intangible assets, net | 2,450 | 2,511 |
| Nuclear decommissioning trust fund | 836 | 1,008 |
| Derivative instruments | 4,548 | 2,527 |
| Deferred income taxes | 1,501 | 2,155 |
| Other non-current assets | 233 | 229 |
| Total other assets | 11,589 | 10,653 |
| **Total Assets** | $ 34,335 | $ 23,182 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Current portion of long-term debt and finance leases | $ 62 | $ 4 |
| Current portion of operating lease liabilities | 82 | 81 |
| Accounts payable | 2,933 | 2,274 |
| Derivative instruments | 8,000 | 3,387 |
| Cash collateral received in support of energy risk management activities | 3,970 | 845 |
| Accrued expenses and other current liabilities | 1,390 | 1,324 |
| Total current liabilities | 16,437 | 7,915 |
| **Other Liabilities** | | |
| Long-term debt and finance leases | 7,970 | 7,966 |
| Non-current operating lease liabilities | 201 | 236 |
| Nuclear decommissioning reserve | 330 | 321 |
| Nuclear decommissioning trust liability | 485 | 666 |
| Derivative instruments | 2,565 | 1,412 |
| Deferred income taxes | 71 | 73 |
| Other non-current liabilities | 976 | 993 |
| Total other liabilities | 12,598 | 11,667 |
| **Total Liabilities** | 29,035 | 19,582 |
| **Commitments and Contingencies** | | |
| **Stockholders' Equity** | | |
| Common stock; $0.01 par value; 500,000,000 shares authorized; 423,868,387 and 423,547,174 shares issued and 235,146,021 and 243,753,899 shares outstanding at June 30, 2022 and December 31, 2021, respectively | 4 | 4 |
| Additional paid-in-capital | 8,442 | 8,531 |
| Retained earnings | 2,600 | 464 |
| Treasury stock, at cost 188,722,366 and 179,793,275 shares at June 30, 2022 and December 31, 2021, respectively | (5,626) | (5,273) |
| Accumulated other comprehensive loss | (120) | (126) |
| **Total Stockholders' Equity** | 5,300 | 3,600 |
| **Total Liabilities and Stockholders' Equity** | $ 34,335 | $ 23,182 |

See accompanying notes to condensed consolidated financial statements.

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

| | Six months ended June 30, | |
|---|---|---|
| **(In millions)** | **2022** | **2021** |
| **Cash Flows from Operating Activities** | | |
| Net Income | $ 2,249 | $ 996 |
| Adjustments to reconcile net income to cash provided by operating activities: | | |
| Distributions from and equity in (losses)/earnings of unconsolidated affiliates | 16 | 14 |
| Depreciation and amortization | 340 | 370 |
| Accretion of asset retirement obligations | 16 | 14 |
| Provision for credit losses | 51 | 651 |
| Amortization of nuclear fuel | 28 | 25 |
| Amortization of financing costs and debt discounts | 11 | 20 |
| Amortization of in-the-money contracts and emissions allowances | 128 | 108 |
| Amortization of unearned equity compensation | 14 | 10 |
| Net gain on sale and disposal of assets | (46) | (25) |
| Impairment losses | 155 | 306 |
| Changes in derivative instruments | (3,918) | (2,430) |
| Changes in deferred income taxes and liability for uncertain tax benefits | 672 | 257 |
| Changes in collateral deposits in support of energy risk management activities | 3,121 | 696 |
| Changes in nuclear decommissioning trust liability | (5) | 30 |
| Uplift securitization proceeds received from ERCOT | 689 | — |
| Changes in other working capital | (332) | (665) |
| **Cash provided by operating activities** | 3,189 | 377 |
| **Cash Flows from Investing Activities** | | |
| Payments for acquisitions of businesses and assets, net of cash acquired | (53) | (3,521) |
| Capital expenditures | (150) | (143) |
| Net (purchases)/sales of emission allowances | (19) | 1 |
| Investments in nuclear decommissioning trust fund securities | (271) | (253) |
| Proceeds from the sale of nuclear decommissioning trust fund securities | 278 | 226 |
| Proceeds from sales of assets, net of cash disposed | 96 | 198 |
| **Cash used by investing activities** | (119) | (3,492) |
| **Cash Flows from Financing Activities** | | |
| Payments of dividends to common stockholders | (168) | (159) |
| Payments for share repurchase activity | (366) | (9) |
| Net receipts from settlement of acquired derivatives that include financing elements | 950 | 191 |
| Net proceeds of Revolving Credit Facility and Receivables Securitization Facilities | — | 75 |
| Repayments of long-term debt and finance leases | (2) | (4) |
| Payments of debt issuance costs | — | (2) |
| Proceeds from issuance of common stock | — | 1 |
| **Cash provided by financing activities** | 414 | 93 |
| Effect of exchange rate changes on cash and cash equivalents | — | 1 |
| **Net Increase/(Decrease) in Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash** | 3,484 | (3,021) |
| **Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at Beginning of Period** | 1,110 | 3,930 |
| **Cash and Cash Equivalents, Funds Deposited by Counterparties and Restricted Cash at End of Period** | $ 4,594 | $ 909 |

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 | Treasury Stock | Accumulated Other Comprehensive Loss | Total Stock-holders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2021** | $ 4 | $ 8,531 | $ 464 | $ (5,273) | $ (126) | $ 3,600 |
| Net income | | | 1,736 | | | 1,736 |
| Other comprehensive income | | | | | 8 | 8 |
| Share repurchases | | | | (187) | | (187) |
| Equity-based awards activity, net[a] | | 2 | | | | 2 |
| Common stock dividends and dividend equivalents declared[b] | | | (86) | | | (86) |
| Adoption of ASU 2020-06 | | (100) | 57 | | | (43) |
| **Balance at March 31, 2022** | $ 4 | $ 8,433 | $ 2,171 | $ (5,460) | $ (118) | $ 5,030 |
| Net income | | | 513 | | | 513 |
| Other comprehensive income | | | | | (2) | (2) |
| Shares reissuance for ESPP | | 1 | | 2 | | 3 |
| Share repurchases | | | | (168) | | (168) |
| Equity-based awards activity, net | | 8 | | | | 8 |
| Common stock dividends and dividend equivalents declared[b] | | | (84) | | | (84) |
| **Balance at June 30, 2022** | $ 4 | $ 8,442 | $ 2,600 | $ (5,626) | $ (120) | $ 5,300 |

| (In millions) | Common Stock | Additional Paid-In Capital | 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 |

(a) Includes $(6) million and $(9) million of equivalent shares purchased in lieu of tax withholding on equity compensation issuances for the quarters ended March 31, 2022 and 2021, respectively

(b) Dividends per common share were $0.35 for the quarters ended June 30 and March 31, 2022 and $0.325 for the quarters ended June 30 and March 31, 2021

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. 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. NRG sells power, natural gas, home and power services, and develops innovative, sustainable solutions, predominately under the brand names NRG, Reliant, Direct Energy, Green Mountain Energy, Stream, and XOOM Energy. The Company has a customer base that includes approximately 6 million Home customers as well as commercial, industrial, and wholesale customers, supported by approximately 17,000 MW of generation.

The Company manages its operations based on the combined results of the retail and wholesale generation businesses with a geographical focus.

The Company's business is segmented as follows:

- Texas, which includes all activity related to customer, plant and market operations in Texas, other than Cottonwood;
- East, which includes all activity related to customer, plant and market operations in the East;
- West/Services/Other, which includes the following assets and activities: (i) all activity related to plant and market operations in the West and Canada, (ii) the Services businesses (iii) activity related to the Cottonwood facility, (iv) the remaining renewables activity, including the Company’s equity method investment in Ivanpah Master Holdings, LLC, and (v) activity related to the Company’s equity method investment for the Gladstone power plant in Australia; and
- Corporate activities.

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 2021 Form 10-K. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim condensed consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly the Company's consolidated financial position as of June 30, 2022, and the results of operations, comprehensive income, cash flows and statements of stockholders' equity for the three and six months ended June 30, 2022 and 2021.

### *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) | June 30, 2022 | December 31, 2021 |
|---|---|---|
| Property, plant and equipment accumulated depreciation | $ 1,387 | $ 1,308 |
| Intangible assets accumulated amortization | 1,932 | 1,636 |

***Credit Losses***

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 six months ended June 30, 2022 and 2021:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| (In millions) | 2022 | 2021 | 2022 | 2021 |
| **Beginning balance** | $ 666 | $ 749 | $ 683 | $ 67 |
| Acquired balance from Direct Energy | — | — | — | 112 |
| Provision for credit losses | 26 | 40 | 51 | 651 |
| Write-offs | (71) | (35) | (121) | (83) |
| Recoveries collected | 6 | 7 | 14 | 14 |
| **Ending balance** | $ 627 | $ 761 | $ 627 | $ 761 |

The decrease in the provision for credit losses during the six months ended June 30, 2022, compared to the same period in 2021 was primarily due to the impacts of Winter Storm Uri during the prior year on bilateral finance hedging risk of $403 million, counterparty credit risk of $120 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) | June 30, 2022 | December 31, 2021 |
|---|---|---|
| Cash and cash equivalents | $ 580 | $ 250 |
| Funds deposited by counterparties | 3,970 | 845 |
| Restricted cash | 44 | 15 |
| Cash and cash equivalents, funds deposited by counterparties and restricted cash shown in the statement of cash flows | $ 4,594 | $ 1,110 |

Funds deposited by counterparties consist of cash held by the Company as a result of collateral posting obligations from its counterparties related to NRG's hedging program. The increase in funds deposited by counterparties is driven by the significant increase in forward positions as a result of increases in natural gas and power prices compared to December 31, 2021. 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 counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company's balance sheet, with an offsetting liability for this cash collateral received within current liabilities.

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

***Winter Storm Uri Uplift Securitization Proceeds***

The Texas Legislature passed House Bill ("HB") 4492 in May of 2021 for ERCOT to mitigate exceptionally high price adders and ancillary service costs incurred by LSEs during Winter Storm Uri. HB 4492 authorized ERCOT to obtain $2.1 billion of financing to distribute to LSEs that were charged and paid to ERCOT those highly priced ancillary service and ORDPA during Winter Storm Uri.

In December 2021, ERCOT filed with the PUCT a calculation of each LSE’s share of proceeds based on the settlement methodology. The Company accounted for the proceeds by analogy to the contribution model within ASC 958-605, *Not-for-Profit Entities- Revenue Recognition* and the grant model within IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance*, as a reduction to cost of operations within its consolidated statements of operations in the 2021 annual period for which the proceeds were intended to compensate. The Company received proceeds of $689 million from ERCOT in June 2022.

***Goodwill***

The Company's goodwill balance was $1.7 billion and $1.8 billion as of June 30, 2022 and December 31, 2021, respectively. The decrease of $138 million in the Company's goodwill balance from December 31, 2021 was due to a $130 million impairment loss related to Midwest Generation in the East segment, $6 million in asset sales in the Texas segment and $2 million primarily due to foreign currency translation in the West/Services/Other segment.

***Recent Accounting Developments - Guidance Adopted in 2022***

*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. The Company adopted this standard on January 1, 2022 using the modified retrospective approach. As a result of the provisions of the amended guidance, the Company recorded a $100 million decrease to additional paid-in capital, a $57 million decrease to debt discount, a $57 million increase to retained earnings and a $14 million decrease to long-term deferred tax liabilities. The adoption of ASU 2020-06 did not have a material impact on the Company's statement of operations, statement of cash flow or earnings per share amounts.

## Note 3 — Revenue Recognition

***Performance Obligations***

As of June 30, 2022, estimated future fixed fee performance obligations are $78 million for the remaining six months of fiscal year 2022, and $77 million, $18 million, $3 million and $1 million for the fiscal years 2023, 2024, 2025 and 2026, respectively. These performance obligations are for cleared auction MWs in the PJM, ISO-NE, NYISO and MISO capacity auctions and are subject to penalties for non-performance.

***Disaggregated Revenues***

The following tables represent the Company's disaggregation of revenue from contracts with customers for the three and six months ended June 30, 2022 and 2021:

| **(In millions)** | **Three months ended June 30, 2022** Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue: | | | | | |
| *Home*[(a)] | *$ 1,661* | *$ 453* | *$ 537* | *$ (1)* | *$ 2,650* |
| *Business* | *910* | *2,947* | *444* | *—* | *4,301* |
| Total retail revenue | 2,571 | 3,400 | 981 | (1) | 6,951 |
| Energy revenue[(b)] | 38 | 128 | 131 | 9 | 306 |
| Capacity revenue[(b)] | — | 89 | 1 | — | 90 |
| Mark-to-market for economic hedging activities[(c)] | (1) | (106) | (38) | (3) | (148) |
| Contract amortization | — | (11) | (2) | — | (13) |
| Other revenue[(b)] | 88 | 16 | (3) | (5) | 96 |
| Total revenue | 2,696 | 3,516 | 1,070 | — | 7,282 |
| Less: Revenues accounted for under topics other than 606 and 815 | — | (4) | 8 | — | 4 |
| Less: Realized and unrealized ASC 815 revenue | (13) | (123) | (70) | 7 | (199) |
| Total revenue from contracts with customers | $ 2,709 | $ 3,643 | $ 1,132 | $ (7) | $ 7,477 |

(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 | $ — | $ (19) | $ (20) | $ 9 | $ (30) |
| Capacity revenue | — | 9 | — | — | 9 |
| Other revenue | (12) | (7) | (12) | 1 | (30) |

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

| **(In millions)** | **Three months ended June 30, 2021** Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue: | | | | | |
| *Home*[(a)] | *$ 1,376* | *$ 416* | *$ 485* | *$ (2)* | *$ 2,275* |
| *Business* | *582* | *1,702* | *257* | *—* | *2,541* |
| Total retail revenue | 1,958 | 2,118 | 742 | (2) | 4,816 |
| Energy revenue[(b)] | 14 | 101 | 55 | 1 | 171 |
| Capacity revenue[(b)] | — | 255 | 16 | — | 271 |
| Mark-to-market for economic hedging activities[(c)] | (3) | (46) | (26) | 5 | (70) |
| Contract amortization | — | (8) | (8) | — | (16) |
| Other revenue[(b)] | 56 | 10 | 7 | (2) | 71 |
| Total revenue | 2,025 | 2,430 | 786 | 2 | 5,243 |
| Less: Revenues accounted for under topics other than 606 and 815 | — | (7) | (7) | — | (14) |
| Less: Realized and unrealized ASC 815 revenue | (2) | 18 | (31) | 4 | (11) |
| Total revenue from contracts with customers | $ 2,027 | $ 2,419 | $ 824 | $ (2) | $ 5,268 |

(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 | $ — | $ 24 | $ (2) | $ (1) | $ 21 |
| Capacity revenue | — | 40 | — | — | 40 |
| Other revenue | 1 | — | (3) | — | (2) |

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

| (In millions) | Six months ended June 30, 2022 Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue: | | | | | |
| *Home*[(a)] | *$ 2,950* | *$ 1,128* | *$ 1,234* | *$ (1)* | *$ 5,311* |
| *Business* | *1,573* | *6,793* | *844* | *—* | *9,210* |
| Total retail revenue | 4,523 | 7,921 | 2,078 | (1) | 14,521 |
| Energy revenue[(b)] | 53 | 332 | 185 | 14 | 584 |
| Capacity revenue[(b)] | — | 204 | 2 | — | 206 |
| Mark-to-market for economic hedging activities[(c)] | (3) | (236) | (56) | 14 | (281) |
| Contract amortization | — | (20) | (2) | — | (22) |
| Other revenue[(b)] | 146 | 33 | 1 | (10) | 170 |
| Total revenue | 4,719 | 8,234 | 2,208 | 17 | 15,178 |
| Less: Revenues accounted for under topics other than 606 and 815 | — | (13) | 19 | — | 6 |
| Less: Realized and unrealized ASC 815 revenue | (20) | (189) | (112) | 27 | (294) |
| Total revenue from contracts with customers | $ 4,739 | $ 8,436 | $ 2,301 | $ (10) | $ 15,466 |

(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 | $ — | $ 26 | $ (40) | $ 13 | $ (1) |
| Capacity revenue | — | 22 | — | — | 22 |
| Other revenue | (17) | (1) | (16) | — | (34) |

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

| (In millions) | Six months ended June 30, 2021 Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue: | | | | | |
| *Home*[(a)] | *$ 2,709* | *$ 1,000* | *$ 1,039* | *$ (2)* | *$ 4,746* |
| *Business* | *1,363* | *4,331* | *538* | *—* | *6,232* |
| Total retail revenue | 4,072 | 5,331 | 1,577 | (2) | 10,978 |
| Energy revenue[(c)] | 299 | 227 | 125 | 2 | 653 |
| Capacity revenue[(c)] | — | 396 | 30 | — | 426 |
| Mark-to-market for economic hedging activities[(d)] | (4) | (50) | (54) | 6 | (102) |
| Contract amortization | — | (8) | (8) | — | (16) |
| Other revenue[(b)(c)] | 1,360 | 29 | 11 | (5) | 1,395 |
| Total revenue | 5,727 | 5,925 | 1,681 | 1 | 13,334 |
| Less: Revenues accounted for under topics other than 606 and 815 | — | (7) | (5) | — | (12) |
| Less: Realized and unrealized ASC 815 revenue | 91 | 117 | (65) | 6 | 149 |
| Total revenue from contracts with customers | $ 5,636 | $ 5,815 | $ 1,751 | $ (5) | $ 13,197 |

(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 | $ — | $ 84 | $ (6) | $ 1 | $ 79 |
| Capacity revenue | — | 77 | — | — | 77 |
| Other revenue | 95 | 6 | (5) | (1) | 95 |

(d) 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 June 30, 2022 and December 31, 2021:

| (In millions) | June 30, 2022 | December 31, 2021 |
|---|---|---|
| Deferred customer acquisition costs | $ 114 | $ 133 |
| | | |
| Accounts receivable, net - Contracts with customers | 3,609 | 3,057 |
| Accounts receivable, net - Derivative instruments and leases | 249 | 182 |
| Accounts receivable, net - Affiliate | 4 | 6 |
| Total accounts receivable, net | $ 3,862 | $ 3,245 |
| | | |
| Unbilled revenues (included within Accounts receivable, net - Contracts with customers) | $ 1,503 | $ 1,574 |
| Deferred revenues[(a)] | 191 | 227 |

(a) Deferred revenues from contracts with customers for the six months ended June 30, 2022 and the year ended December 31, 2021 were approximately $184 million and $224 million, respectively

The revenue recognized from contracts with customers during the six months ended June 30, 2022 and 2021 relating to the deferred revenue balance at the beginning of each period was $117 million and $23 million, respectively. The revenue recognized from contracts with customers during the three months ended June 30, 2022 and 2021 relating to the deferred revenue balance at the beginning of each period was $106 million and $98 million, respectively. The change in deferred revenue balances during the three and six months ended June 30, 2022 and 2021 was primarily due to the usage of customer bill credits by certain C&I customers, which were as a result of power pricing during Winter Storm Uri.

## Note 4 — Acquisitions and Dispositions

***Acquisitions***

***2021 Acquisition of Direct Energy***

On January 5, 2021, the Company acquired all of the issued and outstanding common shares of Direct Energy, which had been 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 total purchase price adjustment of $99 million, resulting in an adjusted purchase price of $3.724 billion. For additional information refer to Note 4, *Acquisitions, Discontinued Operations and Dispositions*, to the Company's 2021 Form 10-K.

***Dispositions***

On June 1, 2022, the Company closed on the sale of its 49% ownership in the Watson natural gas generating facility for $59 million. The Company recorded a gain on the sale of $46 million.

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.

## 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 value and fair value of the Company's financial instruments not carried at fair market value are as follows:

| (In millions) | June 30, 2022 Carrying Amount | June 30, 2022 Fair Value | December 31, 2021 Carrying Amount | December 31, 2021 Fair Value |
|---|---|---|---|---|
| Convertible Senior Notes | $ 575 | $ 623 | $ 518 | $ 677 |
| Other long-term debt, including current portion | 7,523 | 6,573 | 7,522 | 7,650 |
| Total long-term debt, including current portion[(a)] | $ 8,098 | $ 7,196 | $ 8,040 | $ 8,327 |

(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.

***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:

| | June 30, 2022 | | | |
|---|---|---|---|---|
| (In millions) | Total | Level 1 | Level 2 | Level 3 |
| **Investments in securities (classified within other current and non-current assets)** | $ 17 | $ — | $ 17 | $ — |
| **Nuclear trust fund investments:** | | | | |
| Cash and cash equivalents | 17 | 17 | — | — |
| U.S. government and federal agency obligations | 96 | 94 | 2 | — |
| Federal agency mortgage-backed securities | 103 | — | 103 | — |
| Commercial mortgage-backed securities | 36 | — | 36 | — |
| Corporate debt securities | 112 | — | 112 | — |
| Equity securities | 392 | 392 | — | — |
| Foreign government fixed income securities | 2 | — | 2 | — |
| **Other trust fund investments (classified within other non-current assets):** | | | | |
| U.S. government and federal agency obligations | 1 | 1 | — | — |
| **Derivative assets:** | | | | |
| Foreign exchange contracts | 6 | — | 6 | — |
| Commodity contracts | 15,865 | 2,531 | 11,056 | 2,278 |
| **Measured using net asset value practical expedient:** | | | | |
| Equity securities — nuclear trust fund investments | 78 | | | |
| Equity securities (classified within other non-current assets) | 6 | | | |
| **Total assets** | $ 16,731 | $ 3,035 | $ 11,334 | $ 2,278 |
| **Derivative liabilities:** | | | | |
| Commodity contracts | 10,565 | 1,329 | 8,361 | 875 |
| **Total liabilities** | $ 10,565 | $ 1,329 | $ 8,361 | $ 875 |

| (In millions) | December 31, 2021 Total | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| **Investments in securities (classified within other current and non-current assets)** | $ 32 | $ 15 | $ 17 | $ — |
| **Nuclear trust fund investments:** | | | | |
| Cash and cash equivalents | 33 | 33 | — | — |
| U.S. government and federal agency obligations | 112 | 111 | 1 | — |
| Federal agency mortgage-backed securities | 100 | — | 100 | — |
| Commercial mortgage-backed securities | 44 | — | 44 | — |
| Corporate debt securities | 122 | — | 122 | — |
| Equity securities | 494 | 494 | — | — |
| 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 | 7,139 | 981 | 5,701 | 457 |
| **Measured using net asset value practical expedient:** | | | | |
| Equity securities — nuclear trust fund investments | 99 | | | |
| Equity securities (classified within other non-current assets) | 7 | | | |
| **Total assets** | $ 8,188 | $ 1,635 | $ 5,990 | $ 457 |
| **Derivative liabilities:** | | | | |
| Foreign exchange contracts | $ 1 | $ — | $ 1 | $ — |
| Commodity contracts | 4,798 | 626 | 4,008 | 164 |
| **Total liabilities** | $ 4,799 | $ 626 | $ 4,009 | $ 164 |

The following table reconciles, for the three and six months ended June 30, 2022 and 2021, 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) | | | |
|---|---|---|---|---|
| | Derivatives[(a)] | | | |
| (In millions) | Three months ended June 30, 2022 | Three months ended June 30, 2021 | Six months ended June 30, 2022 | Six months ended June 30, 2021 |
| **Beginning balance** | $ 528 | $ 159 | $ 293 | $ (16) |
| Contracts added from Direct Energy acquisition | — | — | — | (15) |
| Total gains realized/unrealized — included in earnings | 293 | 182 | 459 | 362 |
| Purchases | 6 | 58 | 29 | 78 |
| Transfers into Level 3[(b)] | 568 | 168 | 621 | 172 |
| Transfers out of Level 3[(b)] | 8 | 7 | 1 | (7) |
| **Ending balance** | $ 1,403 | $ 574 | $ 1,403 | $ 574 |
| 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 | $ 297 | $ 275 | $ 534 | $ 421 |

(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

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

*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 June 30, 2022, contracts valued with prices provided by models and other valuation techniques make up 14% of derivative assets and 8% 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 June 30, 2022 and December 31, 2021:

| | June 30, 2022 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Fair Value | | | | Input/Range | | |
| (In millions) | Assets | Liabilities | Valuation Technique | Significant Unobservable Input | Low | High | Weighted Average |
| Natural Gas Contracts | $ 55 | $ 56 | Discounted Cash Flow | Forward Market Price (per MMBtu) | $ 3 | $ 17 | $ 5 |
| Power Contracts | 2,144 | 762 | Discounted Cash Flow | Forward Market Price (per MWh) | 7 | 263 | 56 |
| FTRs | 79 | 57 | Discounted Cash Flow | Auction Prices (per MWh) | (307) | 75 | 1 |
| | $ 2,278 | $ 875 | | | | | |

| | December 31, 2021 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Fair Value | | | | Input/Range | | |
| (In millions) | Assets | Liabilities | Valuation Technique | Significant Unobservable Input | Low | High | Weighted Average |
| Natural Gas Contracts | $ 16 | $ 1 | Discounted Cash Flow | Forward Market Price (per MMBtu) | $ 3 | $ 40 | $ 15 |
| Power Contracts | 392 | 121 | Discounted Cash Flow | Forward Market Price (per MWh) | 3 | 212 | 35 |
| FTRs | 49 | 42 | Discounted Cash Flow | Auction Prices (per MWh) | (122) | 43 | 0 |
| | $ 457 | $ 164 | | | | | |

The following table provides sensitivity of fair value measurements to increases/(decreases) in significant unobservable inputs as of June 30, 2022 and December 31, 2021:

| 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 June 30, 2022, the credit reserve resulted in a $5 million decrease primarily within cost of operations. As of December 31, 2021, the credit reserve resulted in a $11 million decrease 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 2021 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 2021 Form 10-K. As of June 30, 2022, counterparty credit exposure, excluding credit exposure from RTOs, ISOs, registered commodity exchanges and certain long-term agreements, was $3.9 billion and NRG held collateral (cash and letters of credit) against those positions of $2.5 billion, resulting in a net exposure of $1.5 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 80% of the Company's exposure before collateral is expected to roll off by the end of 2023. 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 | 78 % |
| Financial institutions | 22 |
| Total as of June 30, 2022 | 100 % |

| **Category by Counterparty Credit Quality** | **Net Exposure [(a)(b)] (% of Total)** |
|---|---|
| Investment grade | 52 % |
| Non-investment grade/non-rated | 48 |
| Total as of June 30, 2022 | 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 exposure to one wholesale counterparty in excess of 10% of total net exposure discussed above as of June 30, 2022. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration.

During the first quarter of 2021, during Winter Storm Uri, the Company experienced a 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 obligations under this transaction but, given the size of the exposure and the counterparty filing for Chapter 11 bankruptcy protection, cannot determine with certainty what the amount of its ultimate recovery will be. The full exposure was provided for in the allowance for credit losses since March 31, 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 June 30, 2022, aggregate credit risk exposure managed by NRG to these counterparties was approximately $1.1 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 June 30, 2022, 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. Current economic conditions may affect the Company’s customers’ ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in credit losses.

**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 June 30, 2022 | | | | As of December 31, 2021 | | | |
|---|---|---|---|---|---|---|---|---|
| (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 | $ 17 | $ — | $ — | — | $ 33 | $ — | $ — | — |
| U.S. government and federal agency obligations | 96 | 1 | 6 | 10 | 112 | 5 | 1 | 10 |
| Federal agency mortgage-backed securities | 103 | — | 7 | 25 | 100 | 2 | — | 25 |
| Commercial mortgage-backed securities | 36 | — | 3 | 27 | 44 | 1 | — | 27 |
| Corporate debt securities | 112 | — | 10 | 13 | 122 | 7 | 1 | 14 |
| Equity securities | 470 | 331 | — | — | 593 | 456 | — | — |
| Foreign government fixed income securities | 2 | — | — | 18 | 4 | — | — | 13 |
| Total | $ 836 | $ 332 | $ 26 | | $ 1,008 | $ 471 | $ 2 | |

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.

| | Six months ended June 30, | |
|---|---|---|
| (In millions) | 2022 | 2021 |
| Realized gains | $ 8 | $ 6 |
| Realized losses | (11) | (4) |
| Proceeds from sale of securities | 278 | 226 |

**Note 7 — Accounting for Derivative Instruments and Hedging Activities**

***Energy-Related Commodities***

As of June 30, 2022, NRG had energy-related derivative instruments extending through 2036. The Company marks these derivatives to market through the statement of operations. NRG has executed energy-related contracts 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 primarily 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 June 30, 2022, NRG had foreign exchange contracts extending through 2025. 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 June 30, 2022 and December 31, 2021. 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 | June 30, 2022 | December 31, 2021 |
| Emissions | Short Ton | — | 1 |
| Renewable Energy Certificates | Certificates | 11 | 13 |
| Coal | Short Ton | 12 | 19 |
| Natural Gas | MMBtu | 832 | 813 |
| Oil | Barrels | — | 1 |
| Power | MWh | 179 | 185 |
| Foreign Exchange | Dollars | $ 405 | $ 279 |

***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) | June 30, 2022 | December 31, 2021 | June 30, 2022 | December 31, 2021 |
| **Derivatives Not Designated as Cash Flow or Fair Value Hedges:** | | | | |
| Foreign exchange contracts - current | $ 3 | $ — | $ — | $ 1 |
| Foreign exchange contracts - long-term | 3 | 1 | — | — |
| Commodity contracts - current | 11,320 | 4,613 | 8,000 | 3,386 |
| Commodity contracts - long-term | 4,545 | 2,526 | 2,565 | 1,412 |
| **Total Derivatives Not Designated as Cash Flow or Fair Value Hedges** | $ 15,871 | $ 7,140 | $ 10,565 | $ 4,799 |

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 June 30, 2022** | | | | |
| **Foreign exchange contracts:** | | | | |
| Derivative assets | $ 6 | $ — | $ — | $ 6 |
| **Commodity contracts:** | | | | |
| Derivative assets | $ 15,865 | $ (9,937) | $ (3,719) | $ 2,209 |
| Derivative liabilities | (10,565) | 9,937 | 73 | (555) |
| **Total commodity contracts** | $ 5,300 | $ — | $ (3,646) | $ 1,654 |
| **Total derivative instruments** | $ 5,306 | $ — | $ (3,646) | $ 1,660 |

| | Gross Amounts Not Offset in the Statement of Financial Position | | | |
|---|---|---|---|---|
| **(In millions)** | **Gross Amounts of Recognized Assets / Liabilities** | **Derivative Instruments** | **Cash Collateral (Held) / Posted** | **Net Amount** |
| **As of December 31, 2021** | | | | |
| **Foreign exchange contracts:** | | | | |
| Derivative assets | $ 1 | $ (1) | $ — | $ — |
| Derivative liabilities | (1) | 1 | — | — |
| **Total foreign exchange contracts** | $ — | $ — | $ — | $ — |
| **Commodity contracts:** | | | | |
| Derivative assets | $ 7,139 | $ (4,440) | $ (831) | $ 1,868 |
| Derivative liabilities | (4,798) | 4,440 | 17 | (341) |
| **Total commodity contracts** | $ 2,341 | $ — | $ (814) | $ 1,527 |
| **Total derivative instruments** | $ 2,341 | $ — | $ (814) | $ 1,527 |

***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 revenues and cost of operations.

| (In millions) | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **Unrealized mark-to-market results** | 2022 | 2021 | 2022 | 2021 |
| Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges | $ (197) | $ 22 | $ (605) | $ 39 |
| Reversal of acquired loss/(gain) positions related to economic hedges | 48 | 103 | (12) | 248 |
| Net unrealized gains on open positions related to economic hedges | 868 | 1,392 | 3,613 | 1,951 |
| Total unrealized mark-to-market gains for economic hedging activities | 719 | 1,517 | 2,996 | 2,238 |
| Reversal of previously recognized unrealized losses/(gains) on settled positions related to trading activity | 8 | (3) | 9 | (10) |
| Net unrealized (losses)/gains on open positions related to trading activity | (10) | (7) | (25) | 4 |
| Total unrealized mark-to-market (losses) for trading activity | (2) | (10) | (16) | (6) |
| **Total unrealized gains** | $ 717 | $ 1,507 | $ 2,980 | $ 2,232 |

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| (In millions) | 2022 | 2021 | 2022 | 2021 |
| Unrealized (losses) included in revenues - commodities | $ (150) | $ (80) | $ (297) | $ (108) |
| Unrealized gains included in cost of operations - commodities | 858 | 1,589 | 3,272 | 2,344 |
| Unrealized gains/(losses) included in cost of operations - foreign exchange | 9 | (2) | 5 | (4) |
| **Total impact to statement of operations - commodities** | $ 717 | $ 1,507 | $ 2,980 | $ 2,232 |

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 revenue or cost of operations during the same period.

For the six months ended June 30, 2022 and 2021, the unrealized gains from open economic hedge positions of $3.6 billion and $2 billion, respectively, were primarily due to increases in the value of forward positions as a result of increases in natural gas and power prices.

***Credit Risk Related Contingent Features***

Certain of the Company's 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. The collateral potentially required for all contracts with adequate assurance clauses that are in a net liability position as of June 30, 2022 was $1.4 billion. 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 approximately $125 million as of June 30, 2022. In the event of a downgrade in the Company's credit rating and if called for by the counterparty, $29 million of additional collateral would be required for all contracts with credit rating contingent features as of June 30, 2022.

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

## Note 8 — Impairments

***2022 Impairment Losses***

*PJM Asset Impairments* — During the second quarter of 2022, the results of the PJM Base Residual Auction for the 2023/2024 delivery year were released leading the Company to revise its long-term view of certain facilities and announce the planned retirement of the Joliet generating facility in May 2023. The Company considered the near-term retirement date of Joliet and the decline in PJM capacity prices 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 generating 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 reporting unit as a whole, and the discount rate applied to the after-tax cash flow projections. Impairment losses of $20 million and $130 million were recorded in the East segment on the PJM generating assets and Midwest Generation goodwill, respectively.

***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 generating 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.

## Note 9 — Long-term Debt and Finance Leases

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

| (In millions, except rates) | June 30, 2022 | December 31, 2021 | Interest rate % |
|---|---|---|---|
| **Recourse debt:** | | | |
| Senior Notes, due 2027 | $ 375 | $ 375 | 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 | 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 | 8,100 | 8,100 | |
| **Finance leases** | 12 | 13 | various |
| Subtotal long-term debt and finance leases (including current maturities) | 8,112 | 8,113 | |
| Less current maturities | (62) | (4) | |
| Less debt issuance costs | (78) | (83) | |
| Discounts | (2) | (60) | |
| Total long-term debt and finance leases | $ 7,970 | $ 7,966 | |

(a) As of the ex-dividend date of July 29, 2022, the Convertible Senior Notes were convertible at a price of $43.77, which is equivalent to a conversion rate of approximately 22.8467 shares of common stock per $1,000 principal amount.

***2048 Convertible Senior Notes***

*Accounting for Convertible Senior Notes* — Upon issuance, the Convertible Senior Notes were separated into liability and equity components for accounting purposes. The carrying amounts of the liability component was initially calculated by measuring the fair value of similar liabilities that do not have an associated convertible feature. The carrying amount of the equity component representing the conversion option was determined by deducting the fair value of the liability component from the par value of the Convertible Senior Notes. This difference represented the debt discount that was amortized to interest expense over seven years, which was determined to be the expected life of the Convertible Senior Notes, using the effective interest rate method. The equity component was recorded in additional paid-in capital and was not remeasured as it continued to meet the conditions for equity classification.

Following the adoption of ASU 2020-06 as of January 1, 2022, the Company no longer records the conversion feature of its convertible senior notes in equity. Instead, the Company combined the previously separated equity component with the liability component, which together is now classified as debt, thereby eliminating the subsequent amortization of the debt discount as interest expense. As a result of the provisions of the amended guidance, the Company recorded a $100 million decrease to additional paid-in capital, a $57 million decrease to debt discount, a $57 million increase to retained earnings and a $14 million decrease to long-term deferred tax liabilities. For more information on the adoption of ASU 2020-06, refer to Note 2, *Summary of Significant Accounting Policies*.

*Modification to Convertible Senior Notes* — On February 22, 2022, the Company irrevocably elected to eliminate the right to settle conversions only in shares of the Company's common stock, such that any conversion after such date, the Company will pay cash per $1,000 principal amount and will settle in cash or a combination of cash and the Company's common stock for the remainder, if any, of the Company's conversion obligation in excess of the aggregate principal amount.

*Convertible Senior Notes Features* — As of June 30, 2022, the Convertible Senior Notes were convertible, under certain circumstances, into cash or a combination of cash and the Company's common stock at a price of $44.15 per common share, which is equivalent to a conversion rate of approximately 22.6516 shares of common stock per $1,000 principal amount of Convertible Senior Notes. The Convertible Senior Notes mature on June 1, 2048, unless earlier repurchased, redeemed or converted in accordance with their terms. The Convertible Senior notes are convertible at the option of the holders under certain circumstances. Prior to the close of business on the business day immediately preceding December 1, 2024, the Convertible

Senior Notes will be convertible only upon the occurrence of certain events and during certain periods, and thereafter during specified periods as follows:

- from December 1, 2024 until the close of business on the second scheduled trading day immediately before June 1, 2025; and
- from December 1, 2047 until the close of business on the second scheduled trading day immediately before the maturity date

The following table details the interest expense recorded in connection with the Convertible Senior Notes, due 2048:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **($ In millions)** | **2022** | **2021** | **2022** | **2021** |
| Contractual interest expense | $ 4 | $ 4 | $ 8 | $ 8 |
| Amortization of discount and deferred finance costs | 1 | 4 | 1 | 8 |
| Total | $ 5 | $ 8 | $ 9 | $ 16 |
| Effective Interest Rate | 0.76 % | 1.32 % | 1.52 % | 2.65 % |

***Receivables Securitization Facilities***

On February 9, 2022, the Company entered into amendments to its existing Repurchase Facility to, among other things, (i) increase the size of the facility from $75 million to $150 million and (ii) replace LIBOR with term SOFR as the benchmark for the pricing rate. The Repurchase Facility has no commitment fee and borrowings will be drawn at SOFR + 1.30%. On July 26, 2022, the Company renewed its existing Repurchase Facility to, among other things, extend the maturity date to July 26, 2023. As of June 30, 2022, there were no outstanding borrowings.

On July 26, 2022, NRG Receivables LLC, a wholly-owned indirect subsidiary of the Company, entered into an amendment to its Receivables Facility dated September 22, 2020 with a group of conduit lenders and banks and Royal Bank of Canada, as Administrative Agent to, among other things, (i) extend the scheduled termination date by one year, (ii) increase the aggregate commitments from $800 million to $1.0 billion, (iii) increase the letter of credit sublimit to equal the aggregate commitments, (iv) replace LIBOR with Term SOFR as the benchmark for borrowings and (v) add new originators. The weighted average interest rate related to usage under the Receivables Facility as of June 30, 2022 was 0.726%. As of June 30, 2022, there were no outstanding borrowings and there were $400 million in letters of credit issued under the Receivables Facility.

***Bilateral Letter of Credit Facilities***

On April 29, 2022 and May 27, 2022, the Company increased the size of the facilities by $100 million and $50 million, respectively, to provide additional liquidity, allowing for the issuance of up to $625 million of letters of credit. As of June 30, 2022, $608 million was issued under these facilities.

**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 June 1, 2022, the Company sold its 49% ownership in the Watson natural gas generating facility to Tesoro Refining & Marketing Company LLC for $59 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, *Long-term Debt and Finance Leases,* to the Company’s 2021 Form 10-K.

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

| (In millions) | June 30, 2022 | December 31, 2021 |
|---|---|---|
| Accounts receivable and Other current assets | $ 1,017 | $ 939 |
| Current liabilities | 153 | 78 |
| Net assets | $ 864 | $ 861 |

## Note 11 — Changes in Capital Structure

As of June 30, 2022 and December 31, 2021, 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, 2021** | 423,547,174 | (179,793,275) | 243,753,899 |
| Shares issued under LTIPs | 321,213 | — | 321,213 |
| Shares issued under ESPP | — | 68,941 | 68,941 |
| Shares repurchased | — | (8,998,032) | (8,998,032) |
| **Balance as of June 30, 2022** | 423,868,387 | (188,722,366) | 235,146,021 |
| Shares issued under LTIPs | 1,121 | — | 1,121 |
| **Balance as of July 31, 2022** | 423,869,508 | (188,722,366) | 235,147,142 |

*Share Repurchases*

On December 6, 2021 the Company announced that the Board of Directors has authorized $1 billion for share repurchases, as part of NRG's capital allocation program. During 2021, $44 million of share repurchases were completed under this authorization. During the six months ended June 30, 2022, the Company completed $355 million of share repurchases under the plan at an average price of $39.43.

The following repurchases have been made during the six months ended June 30, 2022, and through July 31, 2022:

| | Total number of shares and share equivalents purchased | Average price paid per share and share equivalent | Amounts paid for shares and share equivalents purchased (in millions) |
|---|---|---|---|
| **2022 repurchases** | | | |
| Repurchases | 8,998,032 | | $ 355 |
| Equivalent shares purchased in lieu of tax withholdings on equity compensation issuances[(a)] | 138,581 | | 6 |
| **Total Share Repurchases during the six months ended June 30, 2022** | 9,136,613 | $39.48 | 361 |
| Equivalent shares purchased in July in lieu of tax withholdings on equity compensation issuances[(a)] | 635 | | — |
| **Total Share Repurchases January 1, 2022 through July 31, 2022** | 9,137,248 | $39.48 | $ 361 |

(a) NRG elected to pay cash for tax withholding on equity awards instead of issuing actual shares to management. The average price per equivalent shares withheld was $42.89 and $35.98 for the six months ended June 30, 2022 and for July 2022, respectively

*Employee Stock Purchase Plan*

The Company offers 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 2022, NRG increased the annual dividend to $1.40 from $1.30 per share and expects to target an annual dividend growth rate of 7%-9% per share in subsequent years. A quarterly dividend of $0.35 per share was paid on the Company's common stock during the three months ended June 30, 2022. On July 20, 2022, NRG declared a quarterly dividend on the Company's common stock of $0.35 per share, payable on August 15, 2022 to stockholders of record as of August 1, 2022.

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 for periods when we have net income. The Convertible Senior Notes are convertible, under certain circumstances, into cash or combination of cash and Company's common stock. Prior to adoption of ASU 2020-06, there was no dilutive effect for the Convertible Senior Notes due to the Company's expectation to settle the liability in cash. Upon adoption of ASU 2020-06, on January 1, 2022, the Company is including the potential share settlements, if any, in the denominator for purposes of computing diluted income per share under the if converted method for periods when we have net income. The potential shares settlements are calculated as the excess of the Company's conversion obligation over the aggregate principal amount (which will be settled in cash), divided by the average share price for the period. For the periods ended June 30, 2022, there was no dilutive effect for the Convertible Senior Notes since there were no potential share settlements for these periods.

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **(In millions, except per share data)** | **2022** | **2021** | **2022** | **2021** |
| **Basic and diluted income per share:** | | | | |
| Net income | $ 513 | $ 1,078 | $ 2,249 | $ 996 |
| Weighted average number of common shares outstanding - basic and diluted | 237 | 245 | 240 | 245 |
| **Income per weighted average common share — basic and diluted** | $ 2.16 | $ 4.40 | $ 9.37 | $ 4.07 |

As of June 30, 2022, and 2021 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).

| | Three months ended June 30, 2022 | | | | | |
|---|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **East** | **West/Services/ Other** | **Corporate** | **Eliminations** | **Total** |
| Revenue | $ 2,696 | $ 3,516 | $ 1,070 | $ — | $ — | $ 7,282 |
| Depreciation and amortization | 77 | 50 | 22 | 8 | — | 157 |
| Impairment losses | — | 155 | — | — | — | 155 |
| (Loss)/gain on sale of assets | (12) | — | 44 | — | — | 32 |
| Equity in earnings of unconsolidated affiliates | — | — | 4 | — | — | 4 |
| Income/(loss) before income taxes | 766 | (11) | 29 | (119) | — | 665 |
| **Net income/(loss)** | **$ 766** | **$ (10)** | **$ 18** | **$ (261)** | **$ —** | **$ 513** |

| (In millions) | Three months ended June 30, 2021 Texas | East | West/Services/ Other | Corporate | Eliminations | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 2,025 | $ 2,430 | $ 786 | $ — | $ 2 | $ 5,243 |
| Depreciation and amortization | 84 | (56) | 18 | 7 | — | 53 |
| Impairment losses | — | 306 | — | — | — | 306 |
| Equity in earnings of unconsolidated affiliates | — | — | 14 | — | — | 14 |
| Income/(loss) before income taxes | 783 | 783 | 51 | (159) | — | 1,458 |
| **Net income/(loss)** | **$ 783** | **$ 783** | **$ 38** | **$ (526)** | **$ —** | **$ 1,078** |

| (In millions) | Six months ended June 30, 2022 Texas | East | West/Services/ Other | Corporate | Eliminations | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 4,719 | $ 8,234 | $ 2,208 | $ — | $ 17 | $ 15,178 |
| Depreciation and amortization | 153 | 128 | 43 | 16 | — | 340 |
| Impairment losses | — | 155 | — | — | — | 155 |
| (Loss)/gain on sale of assets | (12) | — | 43 | (2) | — | 29 |
| Equity in losses of unconsolidated affiliates | (1) | — | (10) | — | — | (11) |
| Income/(loss) before income taxes | 1,539 | 1,530 | 153 | (250) | — | 2,972 |
| **Net income/(loss)** | **$ 1,539** | **$ 1,531** | **$ 143** | **$ (964)** | **$ —** | **$ 2,249** |

| (In millions) | Six months ended June 30, 2021 Texas | East | West/Services/ Other | Corporate | Eliminations | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 5,727 | $ 5,925 | $ 1,681 | $ — | $ 1 | $ 13,334 |
| Depreciation and amortization | 161 | 150 | 45 | 14 | — | 370 |
| Impairment losses | — | 306 | — | — | — | 306 |
| Gain on sale of assets | — | — | 17 | — | — | 17 |
| Equity in (losses)/earnings of unconsolidated affiliates | (1) | — | 9 | — | — | 8 |
| Income/(loss) before income taxes | 350 | 1,139 | 130 | (328) | — | 1,291 |
| **Net income/(loss)** | **$ 350** | **$ 1,139** | **$ 112** | **$ (605)** | **$ —** | **$ 996** |

## Note 14 — Income Taxes

### *Effective Income Tax Rate*

The income tax provision consisted of the following:

| (In millions, except rates) | Three months ended June 30, 2022 | 2021 | Six months ended June 30, 2022 | 2021 |
|---|---|---|---|---|
| Income before income taxes | $ 665 | $ 1,458 | $ 2,972 | $ 1,291 |
| Income tax expense | 152 | 380 | 723 | 295 |
| Effective income tax rate | 22.9 % | 26.1 % | 24.3 % | 22.9 % |

For the three and six months ended June 30, 2022, the effective tax rates were higher than the statutory rate of 21% primarily due to state tax expense partially offset by tax benefit resulting from the release of valuation allowance on state net operating losses. For the three months ended June 30, 2021, the effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense. For the six months ended June 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.

### *Uncertain Tax Benefits*

As of June 30, 2022, NRG had a non-current tax liability of $20 million for uncertain tax benefits from positions taken on various federal and state income tax returns and accrued interest. For the six months ended June 30, 2022, NRG accrued an immaterial amount of interest relating to the uncertain tax benefits. As of June 30, 2022, NRG had cumulative interest and penalties related to these uncertain tax benefits of $1 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 2013.

## Note 15 — Related Party Transactions

NRG provides services to some of its related parties, who are accounted for as 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:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **(In millions)** | **2022** | **2021** | **2022** | **2021** |
| *Revenues from Related Parties Included in Revenue* | | | | |
| Gladstone | $ — | $ — | $ 1 | $ 1 |
| Ivanpah[a] | 9 | 9 | 22 | 21 |
| Midway-Sunset | 1 | 1 | 3 | 3 |
| Total | $ 10 | $ 10 | $ 26 | $ 25 |

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

## Note 16 — Commitments and Contingencies

### Commitments

***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 would have a claim under the first lien program. As of June 30, 2022, 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 its 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 in an interim order 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 three putative class actions pending against Direct Energy: (1) Linda Stanley v. Direct Energy (S.D.N.Y Apr. 2019) - The parties mediated in June 2021 and agreed on a settlement. In April 2022, the Court granted final approval of the settlement, which was primarily paid during the second quarter of 2022; (2) Martin Forte v. Direct Energy (N.D.N.Y. Mar. 2017) - In December 2021, the Court granted Direct Energy's Motion for summary judgment effectively ending the matter at the district court level. In January 2022, Forte appealed. The briefing is almost complete. Oral arguments are anticipated to be held in September 2022; and (3) Richard Schafer v. Direct Energy (W.D.N.Y. Dec. 2019; on appeal 2nd Cir. N.Y.) - The $2^{nd}$ Circuit sent the matter back to the trial court in December 2021. After brief discovery, Direct Energy is now briefing summary judgment and expects to prevail.

*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) Holly Newman v. Direct Energy, LP (D. Md Sept 2021) - Direct Energy filed its Motion to Dismiss asserting the ruling in the Brittany Burk v. Direct Energy (S.D. Tex. Feb 2019) preempts the Plaintiff's ability to file suit based on the same facts; and (2) Matthew Dickson v. Direct Energy (N.D. Ohio Jan. 2018) - 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. Direct Energy refiled its motions along with supplements. On March 25, 2022, the Court granted summary judgment in favor of Direct Energy and dismissed the case. Dickson appealed his summary judgment loss. Direct Energy is briefing the appeal.

***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 in its capacity as a generator and a retail electric provider. As a power generator, the Company is named in 161 cases with claims ranging from: wrongful death; personal injury only; property damage and personal injury; property damage only; and subrogation. As a retail electric provider, the Company is named in 27 lawsuits with similar claims: wrongful death; property damage only; personal injury only; and both personal injury and property damage. The power generators and retail electric providers are working together to file five motions to dismiss that represent the breadth of the claims filed against them. The briefing is expected to be complete in September 2022. All of the lawsuits related to Winter Storm Uri are consolidated into a single multi-district litigation matter in Harris County District Court. 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 proceeding 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.

**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***

*CPP/ACE Rules* — 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 have vacated the repeal of the CPP). On June 30, 2022, the U.S. Supreme Court held that the "generation shifting" approach in the CPP exceeded the powers granted to the EPA by Congress. The Court did not address the related issues of whether the EPA may adopt only measures applied at each source. The Company anticipates that there will be additional proceedings at the D.C. Circuit and additional rulemaking by the EPA over the next several years.

*Cross-State Air Pollution Rule ("CSAPR")* — In April 2022, the EPA proposed revising the CSAPR to address the good-neighbor provisions of the 2015 ozone NAAQS. If the rule were finalized as proposed, it would apply to 25 states (including Texas) beginning in 2023. In 2023, the revised Group 3 trading program (previously established in the Revised CSAPR Update Rule) would have emission budgets based on NOx emission rates that the EPA says are achievable by existing controls at power plants. Starting in 2026, the NOx budgets would be reduced significantly based on levels achievable if selective catalytic reduction ("SCR") controls were installed at coal-fueled power plants that do not currently have such controls. Starting in 2025, the budgets would be updated annually to account for retirements, changes to operations and new units. The proposal also contemplates heightened surrender requirements for units that exceed certain NOx emission rate thresholds. Comments on the proposed rule were due in June 2022 and numerous detailed comments were submitted. The Company cannot predict the outcome of this proposed revision and anticipates that this rulemaking will be subject to legal challenges after it is finalized.

***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 existing ash rule by extending some of the deadlines and providing more flexibility for compliance. On August 21, 2018, the D.C. Circuit found, among other things, that the EPA had not adequately regulated unlined ponds and legacy ponds. 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.

## 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 six months ended June 30, 2022 and 2021. Also refer to NRG's 2021 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 Estimates section.

### Executive Summary

### Introduction and Overview

NRG is a consumer services company built on dynamic retail brands. 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 power, natural gas, home and power services, and develops innovative, sustainable solutions, predominately under the brand names NRG, Reliant, Direct Energy, Green Mountain Energy, Stream, and XOOM Energy. The Company has a customer base that includes approximately 6 million Home customers as well as commercial, industrial, and wholesale customers, supported by approximately 17,000 MW of generation as of June 30, 2022.

### Strategy

NRG's strategy is to maximize stockholder value through the safe production and sale of reliable electricity and natural 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. Sustainability is a philosophy that underpins and facilitates value creation across our business for our stakeholders. It is an integral piece of NRG's strategy and ties directly to business success, reduced risks and enhanced reputation.

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 assets; (iv) optimal hedging of its portfolio; and (v) engaging in disciplined and transparent capital allocation.

The Company implemented a four-year plan that began in 2022 to spend $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.

### Energy Regulatory Matters

The Company's regulatory matters are described in the Company's 2021 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***

Congress continues to consider using the budget reconciliation process to pass energy efficiency and clean energy tax incentives included in President Biden's original Build Back Better initiative. NRG continues to closely monitor the budget reconciliation process.

***State and Provincial Energy Regulation***

*Illinois Legislation* — Illinois enacted the Climate and Equitable Jobs Act ("CEJA") on September 15, 2021, which targets 100% clean energy by 2050. CEJA focuses on (i) decarbonization, (ii) incentives to transition coal plants into clean energy facilities and (iii) nuclear subsidies. A component of CEJA is the Coal-to-Solar Energy Storage Grant Program. On June 1, 2022, the Illinois Department of Commerce and Economic Opportunity announced that NRG is eligible to receive almost $160 million over 10 years to develop battery storage at both the Waukegan and Will County power plant sites.

***Regional Regulatory Developments***

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

*Texas*

*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 modify the High System Wide Offer cap ("HCAP") and the ORDC, which is intended to ensure prices in the competitive market appropriately reflect the value of operating reserves as the system approaches scarcity conditions. This rulemaking project concluded in December 2021, resulting in a rule amendment that lowered the HCAP to $5,000 per MWh and which expanded the minimum contingency level to 3,000 MW in Phase I. These two changes are broadly offsetting in their effect on overall average energy prices. In 2022, the PUCT has focused on the development of a winter firm fuel product. The PUCT directed ERCOT to issue a Request for Proposal to procure dual fuel capability with on-site fuel storage as part of the initial firm fuel procurement for the winter of 2022 and 2023. The procurement amount will be 3,000MW to 4,000MW and capped at a cost of $54 million. For Phase II, the PUCT Chair endorsed a version of NRG's Load-Serving Entity Reliability Obligation ("LSERO") idea; that retailers and other LSEs should be obliged to purchase an amount of physical reliability resources at critical hours commensurate with the state's newly cautious view of planning for tail events. The PUCT has prioritized the development of a Backstop Reserve Service prior to consideration of an LSERO. ERCOT resource constraints will delay implementation, including Phase II items, by 12 to 24 months. Recently, the South Texas Electric Cooperative ("STEC") has filed a proposal to create a net-load based capacity market that allocates costs to loads, renewables and thermal resources with forced outages. A broad group of stakeholders, including NRG, have expressed support for the PUCT to include the STEC proposal in the blueprint for further review alongside the LSERO even though there is opposition for the specific cost allocation mechanism. The PUCT contracted with consulting firm E3 to develop design details and implementation specifics for the Phase II proposals due in later summer or early fall 2022.

*Activity on Securitization and ERCOT Pricing during Winter Storm Uri* — The Texas Legislature acted to pass a variety of securitization vehicles to finance exceptionally high power and gas costs from Winter Storm Uri, including HB 4492. ERCOT subsequently filed two applications requesting the PUCT to issue Debt Obligation Orders ("DOOs") based on the legislation. On October 13, 2021, the PUCT issued DOOs authorizing ERCOT's securitization of $800 million to cover short payments and reimburse congestion revenue right account holders for amount related to the default of market participants other than electric cooperatives Brazos Electric Cooperative Inc. ("Brazos") and Rayburn Country Electric Cooperative, Inc. ("Rayburn"), which are discussed below (the "Default Securitization") and $2.1 billion related to highly priced ancillary service and ORPDA during Winter Storm Uri (the "Uplift Securitization").

The DOOs require ERCOT to issue loans or securitized bonds through a bankruptcy remote special purpose entity as the borrower and distribute the proceeds to affected market participants for default-related short payments and to LSEs for certain ancillary-service and ORDPA costs using an allocation of proceeds based on an LSE's 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. In turn, ERCOT will charge non-bypassable fees related to the Default Securitization and Uplift Securitization to all qualified scheduling entities and to all LSEs (other than those that have opted-out), respectively. The Uplift Securitization provided for a one-time opt-out for certain LSEs 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 were required by the law to participate, ensuring the charge established by the law is competitively neutral. These opt-outs and calculations of the allocation of proceeds have been finalized. The $2.1 billion Uplift Securitization was disbursed by ERCOT in June 2022, with NRG's LSEs collectively receiving $689 million. NRG LSEs that assessed customers certain ancillary-service and ORDPA costs during the period of Winter Storm Uri will be obligated to provide a refund or credit to those customers proportionate to the LSE's total recovery. The $800 million Default Securitization was disbursed by ERCOT in November 2021, with NRG receiving $12 million.

*Electric Cooperative Bankruptcy and Securitization* — Of the defaults in the ERCOT market, the majority is attributable to Brazos. Brazos currently is in bankruptcy. NRG and ERCOT have both filed a proof of claim in the bankruptcy proceeding of Brazos, and Brazos has challenged ERCOT's claim in a manner that may prejudice NRG's claims against Brazos. During the fourth quarter of 2021, ERCOT filed a motion to dismiss Brazos' complaint relating to ERCOT's proof of claim, which NRG joined in support, but this motion was denied by the Bankruptcy Court, and ERCOT, NRG and certain other parties appealed. On January 11, 2022, the United States District Court for the Southern District of Texas entered an order allowing the appellants to seek direct review from the Fifth Circuit Court of Appeals of the Bankruptcy Court's decision on the motion to dismiss. On January 18, 2022, ERCOT, NRG and certain other parties filed a petition for direct review by the United States Court of Appeals for the Fifth Circuit. The Court of Appeals granted the petition on February 4, 2022. On February 7, 2022, the Bankruptcy Court entered an order granting summary judgment in favor of Brazos on whether ERCOT's sales to Brazos were in the ordinary course of Brazos' business. The Bankruptcy Court ruled that the portion of ERCOT's claims for charges incurred by Brazos after the intervention of the PUCT and ERCOT were not in the ordinary course and thus are not entitled to administrative expense status under the Bankruptcy Code. The amount and priority of ERCOT's claim for amounts incurred prior to such intervention or after such intervention ceased are issues to be determined at trial. The Bankruptcy Court's summary judgment ruling may also apply to NRG's claims again Brazos. To the extent the Bankruptcy Court reduces or disallows claims against Brazos, this presents risk for NRG.

Trial on the merits of the ERCOT proof of claim and Brazos' complaint commenced before the Bankruptcy Court on February 22, 2022. On the eighth day of trial, the parties agreed to suspend the trial and pursue mediation. On March 25, 2022, the Bankruptcy Court entered an order that appointed a mediator and abated the trial for the duration of the mediation. NRG is participating in the mediation with ERCOT, Brazos and various other parties in interest. On April 7, 2022, the Fifth Circuit Court of Appeals entered an order extending briefing deadlines applicable to the pending appeal of the Bankruptcy Court's ruling on the motion to dismiss. Both the mediation schedule and briefing schedule before the Fifth Circuit Court of Appeals have been repeatedly extended. At this time there is no deadline for mediation to conclude, but a party may request that the Bankruptcy Court terminate its participation in the mediation at any point. The current deadline for opening appellate briefs has been extended to August 14, 2022, but the parties have agreed to request a further extension to September 14, 2022, and the deadline may be extended again by further order of the Fifth Circuit Court of Appeals.

ERCOT's current 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 cooperative utilities, and financial traders. However, the total amount of this uplift is limited by ERCOT's current protocols of $2.5 million per month. Consequently, it would take approximately 63 years for the net short-pay balance of $1.887 billion related to Brazos 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 $121 million and has been short-paid $68 million. The remaining $53 million has been discounted based on the 63-year repayment term and present value of $9 million was recorded as an additional liability.

In February 2022, Rayburn successfully completed a securitization transaction and fully paid its outstanding obligations to ERCOT.

*Reliability and Plant Operations Standards* — The PUCT created a rulemaking to establish weatherization standards and issued a notice for comments in response to provisions of Texas Senate Bill 3 ("SB3") that require mandatory standards for power generators and others within the electric-power sector. On October 21, 2021, Commissioners of the PUCT voted to adopt Phase 1 of the rule without substantial modifications from the proposal, and those rules are now in effect. On May 26, 2022, the PUCT issued a proposal for publication to repeal Phase I rules and implement Phase 2 rules. The new rules entail conducting a weather study by ERCOT and the State Climatologist to create a percentile-based standard of weatherization and implementing weatherization plan audits based on weather related outages that occur during weather emergencies. NRG filed comments to the rulemaking on June 23, 2022. The matter is pending at the PUCT.

*PJM*

*Indian River RMR Proceeding* — On June 29, 2021, Indian River notified PJM that it intended to retire Unit 4, effective May 31, 2022, due to expected uneconomic operations. On July 30, 2021, PJM responded to the deactivation notice and stated that PJM had identified reliability violations resulting from the proposed deactivation of Unit 4. NRG filed a cost based RMR rate schedule at FERC on April 1, 2022. FERC accepted the rate schedule with a June 1, 2022 effective date, subject to refund and established hearing and settlement procedures. Multiple parties protested. Parties are currently in settlement negotiations.

*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 and ultimately appealed to the federal court of appeals. On December 21, 2021 and December 30, 2021, respectively, the Third Circuit Court of Appeals and the Seventh Circuit Court of Appeals issued an order holding the appeals in abeyance. The Seventh Court appeal is being held in abeyance while the appeal in the Third Court is moving forward with briefing. 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.

*PJM's ORDC Filing and Compliance Directives* — On May 21, 2020, 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. In addition to approving PJM's proposal, FERC also directed PJM to implement a forward-looking Energy and Ancillary Services Offset to be used in PJM's capacity markets. After multiple compliance filings, 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 and was granted a voluntary remand the case back to the agency. On December 22, 2021, FERC issued its order on voluntary remand affirming in part and reversing in part FERC's determination. Specifically, FERC reversed itself and ordered PJM to: (i) eliminate the more robust ORDC curves and reserve penalty adders and maintain the existing (lower) curves and (lower) penalty adders and (ii) restore its tariff provisions related to its prior backward-looking Energy and Ancillary Services Offset. In response to requests for rehearing of the December 2021 order, FERC issued a notice denying the rehearings by operation of law and providing for further consideration on February 22, 2022. Multiple parties filed appeals in various appellate courts and all appeals are being held in abeyance.

*Independent Market Monitor Market Seller Offer Cap Complaint* — 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 in response to a complaint filed by the PJM Independent Market Monitor's proposal, which eliminates the Cost of New Entry-based Market Seller Offer Cap and implements a limited default cap for certain asset classes based on going-forward costs and provides for unit specific cost review by the Independent Market Monitor for all other non-zero offers into the auctions. As required by the Order, PJM submitted its compliance tariff on October 4, 2021. On October 4, 2021, certain parties filed a motion for rehearing, which was denied by operation of law. On February 18, 2022, FERC addressed the arguments raised on rehearing and rejected the rehearing requests. Multiple parties filed appeals at the Court of Appeals for the D.C. Circuit. The appeals were held in abeyance, but on April 13, 2022, the Court of Appeals removed the appeals from abeyance. Briefing is underway.

*Generator Interconnection Process Reform* — On June 14, 2022, PJM filed proposed tariff revisions at FERC regarding its interconnection process to provide for a more efficient process and address the backlog in interconnection service requests. The filing would transition the interconnect process from a "first-come, first-served" queue approach to a "first-ready, first-served" cluster/cycle approach. Additionally, project developers would be required to provide more significant financial deposits and meet other thresholds in order to move forward in the process. The filing is pending at FERC.

On June 16, 2022, FERC issued a Notice of Proposed Rulemaking to reform the generator interconnection procedures across the ISOs/RTOs. Comments in response to the Notice are due October 13, 2022.

*New York*

*NYISO's Revisions to the Buyer-Side Mitigation Rules* — On January 5, 2022, the NYISO filed its Comprehensive Mitigation Review proposing changes to the buyer-side mitigation rules. The proposal would remove certain facilities to be reviewed under the buyer-side mitigation rules to serve the goals of New York's Climate Leadership and Community Protection Act, adopt a marginal capacity accreditation market design and adjust the rules surrounding installed and unforced capacity. On February 9, 2022, FERC issued a deficiency notice, focusing on capacity accreditation issues, which NYISO responded. On May 10, 2022, FERC issued an order accepting the NYISO's Comprehensive Mitigation Review. Changes to NYISO's Buyer Side Mitigation rules may impact the outcome of future capacity auctions.

*California*

*California Resource Adequacy Proceedings* — As part of the Integrated Resource Procurement docket, the CPUC approved a decision on June 24, 2021 that will require all LSEs to procure a pro rata share of 11.5 GW of new non-fossil resource adequacy from 2023 to 2026. The state has also taken action to procure additional resources beyond those required by all LSEs. First, the CPUC directed the state's major investor-owned utilities to procure additional summer reliability resources, up to 3 GW in total for the summers of 2021 through 2023. In the same docket, the CPUC expanded demand response programs for use during emergency conditions. Second, the 2022 state budget included $2.2 billion for a Strategic Reliability Reserve Fund, which will compensate utilities for above market import resource adequacy ("RA") costs for the summer of 2022 and allow the Department of Water Resources to enter into contracts for new capacity and capacity at risk of retirement. On June 23, 2022, the CPUC approved a decision that has impacts to short-term RA procurement requirements and the long-term RA structure. The decision raises the reserve margin from 15 percent to 16 percent in 2023 and at least 17 percent in 2024. In addition, the value of solar for RA requirements was reduced for the months of March through August. Starting in 2025, LSEs must demonstrate sufficient RA resources to meet their load for all hours of the day, not just the gross peak. The change to RA showings will also require changes to resource counting methodologies. The result of these changes will likely keep RA prices elevated and increase the cost to serve retail load in California.

*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 RMR resource conditioned on execution of a RMR contract. 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. On September 27, 2021, the CAISO gave notice to MSCC extending the term of the reliability designation through December 31, 2022. On April 29, 2022, the participants in the settlement proceeding filed a Joint Offer of Settlement with the FERC, which was approved by FERC on July 28, 2022.

**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. 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 current 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 2021 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 have vacated the repeal of the CPP). On June 30, 2022, the U.S. Supreme Court held that the "generation shifting" approach in the CPP exceeded the powers granted to the EPA by Congress. The Court did not address the related issues of whether the EPA may adopt only measures applied at each source. The Company anticipates that there will be additional proceedings at the D.C. Circuit and additional rulemaking by the EPA over the next several years.

*Cross-State Air Pollution Rule ("CSAPR")* — In April 2022, the EPA proposed revising the CSAPR to address the good-neighbor provisions of the 2015 ozone NAAQS. If the rule were finalized as proposed, it would apply to 25 states (including Texas) beginning in 2023. In 2023, the revised Group 3 trading program (previously established in the Revised CSAPR Update Rule) would have emission budgets based on NOx emission rates that the EPA says are achievable by existing controls at power plants. Starting in 2026, the NOx budgets would be reduced significantly based on levels achievable if SCR controls were installed at coal-fueled power plants that do not currently have such controls. Starting in 2025, the budgets would be updated annually to account for retirements, changes to operations, and new units. The proposal also contemplates heightened surrender requirements for units that exceed certain NOx emission rate thresholds. Comments on the proposed rule were due in June 2022 and numerous detailed comments were submitted. The Company cannot predict the outcome of this proposed revision and anticipates that this rulemaking will be subject to legal challenges after it is finalized.

***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.

***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 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.

***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 2022 as further described within this Management's Discussion and Analysis and the condensed consolidated financial statements:

*W.A. Parish Extended Outage*

In May 2022, W.A. Parish Unit 8 came offline as a result of damage to certain components of the steam turbine/generator. Based on management's current assessment of necessary restoration efforts, the Company is targeting to return the unit to service by the end of the second quarter of 2023.

*Retirement of Joliet*

During the second quarter of 2022, the results of the PJM Base Residual Auction for the 2023/2024 delivery year were released leading the Company to revise its long-term view of certain facilities and announce the planned retirement of the Joliet generating facility in May 2023. Impairment losses of $20 million and $130 million were recorded on the PJM generating assets and Midwest Generation goodwill, respectively.

*ERCOT Securitization Proceeds*

During 2021, the Texas Legislature passed HB 4492 for ERCOT to mitigate exceptionally high price adders and ancillary service costs incurred by LSEs during Winter Storm Uri. HB 4492 authorized ERCOT to obtain $2.1 billion of financing to distribute to LSEs that were charged and paid to ERCOT those highly priced ancillary service and ORDPA during Winter Storm Uri. In December 2021, the Company accounted for the proceeds as a reduction to cost of operations within its consolidated statements of operations in the 2021 annual period for which the proceeds were intended to compensate. The Company received proceeds of $689 million from ERCOT in June 2022.

*Sale of Watson*

On June 1, 2022, the Company closed on the sale of its 49% ownership in the Watson natural gas generating facility to Tesoro Refining & Marketing Company LLC for $59 million. NRG recognized a gain on the sale of $46 million.

*Share Repurchases*

In December 2021, the Company's board of directors authorized the Company to repurchase $1.0 billion of its common stock, of which $44 million was completed in 2021. During the six months ended June 30, 2022, the Company completed $361 million of share repurchases at an average price of $39.48 per share, including $6 million of equivalent shares purchased in lieu of tax withholdings on equity compensation issuances.

*Dividend Increase*

In the first quarter of 2022, NRG increased the annual dividend to $1.40 from $1.30 per share, representing an 8% increase from 2021. The Company expects to target an annual dividend growth rate of 7-9% per share in subsequent years.

*Renewable Power Purchase Agreements*

The Company's strategy is to procure mid to long-term generation through power purchase agreements. As of June 30, 2022, NRG has entered into PPAs totaling approximately 2.4 GW with third-party project developers and other counterparties, of which approximately 41% are operational. The average tenor of these agreements is twelve years. The Company expects to continue evaluating and executing similar agreements that support the needs of the business. The total GW procured through PPAs may be impacted by contract terminations when they occur.

*Limestone Unit 1 Return to Service*

In early July 2021, Limestone Unit 1 came offline as a result of damage to the duct work associated with the FGD system. The extended forced outage ended in April of 2022 and the unit has returned to service.

**COVID-19**

While the pandemic presents risks to the Company's business, as further described in the Company's 2021 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 six months ended June 30, 2022 and 2021.

**Trends Affecting Results of Operations and Future Business Performance**

The Company's trends are described in the Company's 2021 Form 10-K in Item 7, M*anagement's Discussion and Analysis of Financial Condition and Results of Operations - Business Environment.*

**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 June 30, 2022 | 2021 | Change | Six months ended June 30, 2022 | 2021 | Change |
|---|---|---|---|---|---|---|
| **Revenue** | | | | | | |
| Retail revenue | $ 6,951 | $ 4,816 | $2,135 | $ 14,521 | $ 10,978 | $3,543 |
| Energy revenue[a] | 306 | 171 | 135 | 584 | 653 | (69) |
| Capacity revenue[a] | 90 | 271 | (181) | 206 | 426 | (220) |
| Mark-to-market for economic hedging activities | (148) | (70) | (78) | (281) | (102) | (179) |
| Contract amortization | (13) | (16) | 3 | (22) | (16) | (6) |
| Other revenues[a][b] | 96 | 71 | 25 | 170 | 1,395 | (1,225) |
| Total revenue | 7,282 | 5,243 | 2,039 | 15,178 | 13,334 | 1,844 |
| **Operating Costs and Expenses** | | | | | | |
| Cost of fuel | 532 | 298 | (234) | 861 | 1,064 | 203 |
| Purchased energy and other cost of sales[c] | 5,811 | 3,716 | (2,095) | 12,263 | 10,133 | (2,130) |
| Mark-to-market for economic hedging activities | (867) | (1,587) | (720) | (3,277) | (2,340) | 937 |
| Contract and emissions credit amortization[c] | (35) | 63 | 98 | 103 | 64 | (39) |
| Operations and maintenance | 354 | 359 | 5 | 690 | 704 | 14 |
| Other cost of operations | 92 | 99 | 7 | 177 | 180 | 3 |
| Cost of operations (excluding depreciation and amortization shown below) | 5,887 | 2,948 | (2,939) | 10,817 | 9,805 | (1,012) |
| Depreciation and amortization | 157 | 53 | (104) | 340 | 370 | 30 |
| Impairment losses | 155 | 306 | 151 | 155 | 306 | 151 |
| Selling, general and administrative costs | 325 | 317 | (8) | 647 | 654 | 7 |
| Provision for credit losses | 26 | 40 | 14 | 51 | 651 | 600 |
| Acquisition-related transaction and integration costs | 10 | 22 | 12 | 18 | 64 | 46 |
| Total operating costs and expenses | 6,560 | 3,686 | (2,874) | 12,028 | 11,850 | (178) |
| Gain on sale of assets | 32 | — | 32 | 29 | 17 | 12 |
| **Operating Income** | 754 | 1,557 | (803) | 3,179 | 1,501 | 1,678 |
| **Other Income/(Expense)** | | | | | | |
| Equity in earnings/(losses) of unconsolidated affiliates | 4 | 14 | (10) | (11) | 8 | (19) |
| Other income, net | 12 | 12 | — | 12 | 34 | (22) |
| Interest expense | (105) | (125) | 20 | (208) | (252) | 44 |
| Total other expense | (89) | (99) | 10 | (207) | (210) | 3 |
| **Income Before Income Taxes** | 665 | 1,458 | (793) | 2,972 | 1,291 | 1,681 |
| Income tax expense | 152 | 380 | 228 | 723 | 295 | (428) |
| **Net Income** | $ 513 | $ 1,078 | $ (565) | $ 2,249 | $ 996 | $1,253 |
| **Business Metrics** | | | | | | |
| Average natural gas price — Henry Hub ($/MMBtu) | $ 7.17 | $ 2.83 | 153 % | $ 6.06 | $ 2.76 | 120 % |

(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 June 30, 2022 and 2021**

***Electricity Prices***

The following table summarizes average on peak power prices for each of the major markets in which NRG operates for the three months ended June 30, 2022 and 2021. Texas, East and West average on-peak power prices increased for the three months ended June 30, 2022 as compared to the same period in 2021 as a result of higher natural gas prices.

| | Average on Peak Power Price ($/MWh) | | |
|---|---|---|---|
| | Three months ended June 30, | | |
| Region | 2022 | 2021 | Change % |
| Texas | | | |
| ERCOT - Houston[(a)] | $ 126.30 | $ 53.38 | 137 % |
| ERCOT - North[(a)] | 79.14 | 43.05 | 84 % |
| | | | |
| East | | | |
| NY J/NYC[(b)] | $ 81.32 | $ 32.65 | 149 % |
| NEPOOL[(b)] | 73.28 | 33.67 | 118 % |
| COMED (PJM)[(b)] | 84.77 | 32.12 | 164 % |
| PJM West Hub[(b)] | 93.00 | 33.71 | 176 % |
| | | | |
| West | | | |
| MISO - Louisiana Hub[(b)] | $ 91.97 | $ 34.68 | 165 % |
| CAISO - SP15[(b)] | 60.34 | 36.90 | 64 % |

(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 June 30, 2022 and 2021:

| | Average Realized Power Price ($/MWh) | | |
|---|---|---|---|
| | Three months ended June 30, | | |
| Segment | 2022 | 2021 | Change % |
| East[(a)] | $ 59.10 | $ 33.94 | 74 % |
| West/Services/Other | 69.90 | 32.76 | 113 % |

(a) Average Realized Power Price reflects energy sales from the generation fleet, including sales to the retail component of the East Segment. Intercompany financial transactions hedging generation with the retail business make up ($6.68)/MWh in the three months ended June 30, 2022 and ($6.87)/MWh in the three months ended June 30, 2021

The average realized power prices increased in the East and West/Services/Other segments for the three months ended June 30, 2022 as compared to the same period in 2021, as a result of higher natural gas prices and the Company's multi-year hedging program.

***Gross Margin***

The Company calculates gross margin in order to evaluate operating performance as revenues less cost of fuel, purchased energy and 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 retail revenue, energy revenue, capacity revenue and other revenue, less cost of fuel, purchased energy and other cost of sales. Economic gross margin does not include mark-to-market gains or losses on economic hedging activities, contract amortization, 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 three months ended June 30, 2022 and 2021:

| ($ In millions) | Three months ended June 30, 2022 Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue | $ 2,571 | $ 3,400 | $ 981 | $ (1) | $ 6,951 |
| Energy revenue | 38 | 128 | 131 | 9 | 306 |
| Capacity revenue | — | 89 | 1 | — | 90 |
| Mark-to-market for economic hedging activities | (1) | (106) | (38) | (3) | (148) |
| Contract amortization | — | (11) | (2) | — | (13) |
| Other revenue[(a)] | 88 | 16 | (3) | (5) | 96 |
| Total revenue | 2,696 | 3,516 | 1,070 | — | 7,282 |
| Cost of fuel | (354) | (72) | (106) | — | (532) |
| Purchased energy and other cost of sales[(b)(c)(d)] | (1,685) | (3,267) | (855) | (4) | (5,811) |
| Mark-to-market for economic hedging activities | 607 | 242 | 15 | 3 | 867 |
| Contract and emission credit amortization | 2 | 36 | (3) | — | 35 |
| Depreciation and amortization | (77) | (50) | (22) | (8) | (157) |
| **Gross margin** | **$ 1,189** | **$ 405** | **$ 99** | **$ (9)** | **$ 1,684** |
| Less: Mark-to-market for economic hedging activities, net | 606 | 136 | (23) | — | 719 |
| Less: Contract and emission credit amortization, net | 2 | 25 | (5) | — | 22 |
| Less: Depreciation and amortization | (77) | (50) | (22) | (8) | (157) |
| **Economic gross margin** | **$ 658** | **$ 294** | **$ 149** | **$ (1)** | **$ 1,100** |

(a) Includes trading gains and losses and ancillary revenues

(b) Includes capacity and emissions credits

(c) Includes $796 million, $50 million and $275 million of TDSP expense in Texas, East, and West/Services/Other, respectively

(d) Excludes depreciation and amortization shown separately

| Business Metrics | Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| **Retail sales** | | | | | |
| Home power sales volume (GWh) | 11,587 | 3,022 | 487 | — | 15,096 |
| Business power sales volume (GWh) | 10,162 | 12,210 | 2,442 | — | 24,814 |
| Home natural gas sales volume (MDth) | — | 12,681 | 14,333 | — | 27,014 |
| Business natural gas sales volume (MDth) | — | 322,905 | 37,829 | — | 360,734 |
| Average retail Home customer count (in thousands) [(a)(b)] | 3,029 | 1,789 | 786 | — | 5,604 |
| Ending retail Home customer count (in thousands) [(a)(b)] | 3,008 | 1,808 | 785 | — | 5,601 |
| **Power generation** | | | | | |
| GWh sold | 10,035 | 1,946 | 1,874 | — | 13,855 |
| GWh generated[(c)] | | | | | |
| Coal | 4,852 | 1,361 | — | — | 6,213 |
| Gas | 2,661 | 37 | 1,876 | — | 4,574 |
| Nuclear | 2,522 | — | — | — | 2,522 |
| Renewables | — | — | 4 | — | 4 |
| Total | 10,035 | 1,398 | 1,880 | — | 13,313 |

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

(b) The whole home warranty business was sold in January 2022

(c) Includes owned and leased generation, excludes tolled generation and equity investments

| ($ In millions) | Three months ended June 30, 2021 Texas | East | West/ Services/Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue | $ 1,958 | $ 2,118 | $ 742 | $ (2) | $ 4,816 |
| Energy revenue | 14 | 101 | 55 | 1 | 171 |
| Capacity revenue | — | 255 | 16 | — | 271 |
| Mark-to-market for economic hedging activities | (3) | (46) | (26) | 5 | (70) |
| Contract amortization | — | (8) | (8) | — | (16) |
| Other revenue[(a)] | 56 | 10 | 7 | (2) | 71 |
| Total revenue | 2,025 | 2,430 | 786 | 2 | 5,243 |
| Cost of fuel | (214) | (45) | (39) | — | (298) |
| Purchased energy and other cost of sales[(b)(c)(d)] | (1,174) | (1,906) | (637) | 1 | (3,716) |
| Mark-to-market for economic hedging activities | 628 | 897 | 67 | (5) | 1,587 |
| Contract and emission credit amortization | 8 | (69) | (2) | — | (63) |
| Depreciation and amortization | (84) | 56 | (18) | (7) | (53) |
| **Gross margin** | **$ 1,189** | **$ 1,363** | **$ 157** | **$ (9)** | **$ 2,700** |
| Less: Mark-to-market for economic hedging activities, net | 625 | 851 | 41 | — | 1,517 |
| Less: Contract and emission credit amortization, net | 8 | (77) | (10) | — | (79) |
| Less: Depreciation and amortization | (84) | 56 | (18) | (7) | (53) |
| **Economic gross margin** | **$ 640** | **$ 533** | **$ 144** | **$ (2)** | **$ 1,315** |

(a) Includes trading gains and losses and ancillary revenues

(b) Includes capacity and emissions credits

(c) Includes $612 million, $47 million and $265 million of TDSP expense in Texas, East, and West/Services/Other, respectively

(d) Excludes depreciation and amortization shown separately

| Business Metrics | Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| **Retail sales** | | | | | |
| Home power sales volume (GWh) | 10,632 | 3,350 | 495 | — | 14,477 |
| Business power sales volume (GWh) | 8,074 | 12,653 | 2,290 | — | 23,017 |
| Home natural gas sales volume (MDth) | — | 11,332 | 14,086 | — | 25,418 |
| Business natural gas sales volume (MDth) | — | 327,755 | 25,430 | — | 353,185 |
| Average retail Home customer count (in thousands)[(a)(b)] | 3,076 | 1,884 | 970 | — | 5,930 |
| Ending retail Home customer count (in thousands)[(a)(b)] | 3,027 | 1,869 | 967 | — | 5,863 |
| **Power generation** | | | | | |
| GWh sold | 9,878 | 2,475 | 1,679 | — | 14,032 |
| GWh generated[(c)] | | | | | |
| Coal | 4,791 | 1,240 | — | — | 6,031 |
| Gas[(d)] | 2,896 | 468 | 1,650 | — | 5,014 |
| Nuclear | 2,191 | — | — | — | 2,191 |
| Oil[(e)] | — | 63 | — | — | 63 |
| Total | 9,878 | 1,771 | 1,650 | — | 13,299 |

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

(b) Includes 152 thousand whole home warranty customers in West/Services/Other. The whole home warranty business was sold in January 2022

(c) Includes owned and leased generation, excludes tolled generation and equity investments

(d) Includes 258 GWh and 306 GWh in East and West/Services/Other, respectively, that was sold to Generation Bridge in December 2021

(e) Includes 63 GWh in East that was sold to Generation Bridge in December 2021

The table below represents the weather metrics for the three months ended June 30, 2022 and 2021:

| | Three months ended June 30, | | |
|---|---|---|---|
| **Weather Metrics** | **Texas** | **East** | **West/Services/ Other [b]** |
| **2022** | | | |
| CDDs [a] | 1,283 | 352 | 674 |
| HDDs [a] | 24 | 486 | 194 |
| **2021** | | | |
| CDDs | 899 | 362 | 521 |
| HDDs | 82 | 541 | 192 |
| **10-year average** | | | |
| CDDs | 970 | 356 | 549 |
| HDDs | 66 | 492 | 183 |

(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 decreased $1.0 billion and economic gross margin decreased $215 million during the three months ended June 30, 2022, compared to the same period in 2021.

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 in 2021, primarily due to revenue estimation true ups to billed amounts to customers. | $ 45 |
| **The following explanations exclude the impact of Winter Storm Uri:** | |
| Higher gross margin due to an increase in load of 1.95 million MWhs due to weather | 66 |
| Lower gross margin due to the net effect of:<br>• a 44%, or $288 million, increase in overall average costs to serve the retail load, driven by increases in power, ancillary, and fuel costs and the extended outage at W.A. Parish Unit 8 that began in the second quarter of 2022, partially offset by the favorable impact of the early settlement of an online renewable PPA; and<br>• increased net revenue rates of $9.50 per MWh, or $179 million, and higher gross margin attributable to increased load of 740,000 MWhs, or $22 million, both primarily driven by changes in customer mix | (87) |
| Lower gross margin due to market optimization activities | (12) |
| Other | 6 |
| **Increase in economic gross margin** | $ 18 |
| Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges | (19) |
| Increase in contract and emission credit amortization | (6) |
| Decrease in depreciation and amortization | 7 |
| **Change in gross margin** | **$ —** |

*East*

| | | (In millions) |
|---|---|---|
| Higher gross margin due to the impact of Winter Storm Uri in 2021, due to revenue estimation true ups to billed amounts to customers | $ | 8 |
| **The following explanations exclude the impact of Winter Storm Uri:** | | |
| Lower gross margin due to the sale of fossil generating assets to Generation Bridge in December 2021 | | (60) |
| Lower demand response gross margin primarily from a reduction in early settlements of capacity obligations in 2022 compared to 2021 | | (88) |
| Lower power gross margin due to higher supply costs of \$20.50 per MWh, driven primarily by increases in power prices, totaling \$318 million, partially offset by higher net revenue rates as a result of changes in customer term, product and mix of \$16.00 per MWh, or \$247 million | | (71) |
| Lower natural gas gross margin due to higher supply costs of \$3.77 per Dth, or \$1.256 billion, partially offset by higher net revenue rates as a result of changes in customer term, product and mix of \$3.74 per Dth, or \$1.248 billion | | (8) |
| Lower gross margin primarily due to a 42% decrease in New York realized capacity prices and a 9% decrease in PJM capacity prices. | | (13) |
| Lower gross margin from market optimization activities | | (7) |
| **Decrease in economic gross margin** | $ | (239) |
| Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges | | (715) |
| Decrease in contract amortization | | 102 |
| Increase in depreciation and amortization | | (106) |
| **Decrease in gross margin** | **$** | **(958)** |

*West/Services/Other*

| | | (In millions) |
|---|---|---|
| Lower gross margin due to the sale of fossil generating assets to Generation Bridge in December 2021 | $ | (14) |
| Higher power gross margin due to an increase in net revenue rates as a result of changes in customer term, product and mix of \$14.00 per MWh, or \$31 million, and increased load due to change in customer mix of \$3 million, partially offset by higher supply costs of \$6.00 per MWh, or \$14 million, primarily due to increases in power prices | | 20 |
| Lower natural gas gross margin due to higher supply costs of \$2.90 per Dth, or \$147 million, partially offset by higher net revenue rates of \$2.70 per Dth, or \$136 million, and higher natural gas gross margin from increased load due to changes in customer mix totaling \$7 million | | (4) |
| Higher gross margin for the services business primarily due to the Airtron business, partially offset by a decrease in gross margin due to the sale of the whole home warranty business in the first quarter of 2022 | | 3 |
| **Increase in economic gross margin** | $ | 5 |
| Decrease in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges | | (64) |
| Decrease in contract amortization | | 5 |
| Increase in depreciation and amortization | | (4) |
| **Decrease in gross margin** | **$** | **(58)** |

***Mark-to-Market for Economic Hedging Activities***

Mark-to-market for economic hedging activities includes asset-backed hedges that have not been designated as cash flow hedges. Total net mark-to-market results decreased by $798 million during the three months ended June 30, 2022, compared to the same period in 2021.

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

| | Three months ended June 30, 2022 | | | | |
|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **East** | **West/Services/ Other** | **Eliminations** | **Total** |
| **Mark-to-market results in revenue** | | | | | |
| Reversal of previously recognized unrealized losses on settled positions related to economic hedges | $ — | $ 1 | $ 6 | $ (2) | $ 5 |
| Reversal of acquired (gain) positions related to economic hedges | — | (1) | — | — | (1) |
| Net unrealized (losses) on open positions related to economic hedges | (1) | (106) | (44) | (1) | (152) |
| **Total mark-to-market (losses) in revenue** | $ (1) | $ (106) | $ (38) | $ (3) | $ (148) |
| **Mark-to-market results in operating costs and expenses** | | | | | |
| Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges | $ (51) | $ (135) | $ (18) | $ 2 | $ (202) |
| Reversal of acquired loss positions related to economic hedges | 19 | 25 | 5 | — | 49 |
| Net unrealized gains on open positions related to economic hedges | 639 | 352 | 28 | 1 | 1,020 |
| **Total mark-to-market gains in operating costs and expenses** | $ 607 | $ 242 | $ 15 | $ 3 | $ 867 |

| | Three months ended June 30, 2021 | | | | |
|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **East** | **West/Services/ Other** | **Eliminations** | **Total** |
| **Mark-to-market results in revenue** | | | | | |
| Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges | $ (1) | $ (4) | $ — | $ (1) | $ (6) |
| Reversal of acquired (gain) positions related to economic hedges | — | (1) | — | — | (1) |
| Net unrealized (losses) on open positions related to economic hedges | (2) | (41) | (26) | 6 | (63) |
| **Total mark-to-market (losses) in revenue** | $ (3) | $ (46) | $ (26) | $ 5 | $ (70) |
| **Mark-to-market results in operating costs and expenses** | | | | | |
| Reversal of previously recognized unrealized losses/(gains) on settled positions related to economic hedges | $ 30 | $ (1) | $ (2) | $ 1 | $ 28 |
| Reversal of acquired loss positions related to economic hedges | 31 | 59 | 14 | — | 104 |
| Net unrealized gains on open positions related to economic hedges | 567 | 839 | 55 | (6) | 1,455 |
| **Total mark-to-market gains in operating costs and expenses** | $ 628 | $ 897 | $ 67 | $ (5) | $ 1,587 |

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

For the three months ended June 30, 2022, the $148 million loss in revenues from economic hedge positions was driven primarily by a decrease in the value of open positions as a result of increases in PJM power prices. The $867 million gain in operating costs and expenses from economic hedge positions was driven primarily by an increase in the value of open positions as a result of increases in natural gas and power prices, partially offset by the reversal of previously recognized unrealized gains on contracts that settled during the period.

For the three months ended June 30, 2021, the $70 million loss in revenues from economic hedge positions was driven primarily by a decrease in the value of open positions as a result of increases in power prices across all segments. The $1.6 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.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the three months ended June 30, 2022 and 2021. The realized and unrealized financial and physical trading results are included in revenue. The Company's trading activities are subject to limits based on the Company's Risk Management Policy.

| | Three months ended June 30, | |
|---|---|---|
| **(In millions)** | **2022** | **2021** |
| **Trading (losses)/gains** | | |
| Realized | $ (5) | $ 9 |
| Unrealized | (2) | (10) |
| Total trading (losses) | $ (7) | $ (1) |

***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 June 30, 2022 | $ 196 | $ 114 | $ 45 | $ — | $ (1) | $ 354 |
| Three months ended June 30, 2021 | 176 | 122 | 61 | 2 | (2) | 359 |

Operations and maintenance expense decreased by $5 million for the three months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | **(In millions)** |
|---|---|
| Decrease due to the sale of fossil generating assets to Generation Bridge in December 2021 | $ (27) |
| Decrease due to spare parts inventory reserves recorded in 2021 driven by announced retirements of certain PJM coal assets | (9) |
| Decrease driven by current year scrap material sales associated with the demolition of the Encina site | (6) |
| Decrease driven by higher maintenance resulting from the impacts of Winter Storm Uri | (2) |
| Increase in the estimate of environmental remediation costs at a deactivated site in the East | 19 |
| Increase driven by higher retail operations costs | 9 |
| Increase in variable operation and maintenance expense at the PJM coal facilities associated with increased generation in 2022 as compared to 2021 | 7 |
| Other | 4 |
| Decrease in operations and maintenance expense | $ (5) |

***Other Cost of Operations***

Other cost of operations are comprised of the following:

| **(In millions)** | **Texas** | **East** | **West/Services/ Other** | **Total** |
|---|---|---|---|---|
| Three months ended June 30, 2022 | $ 51 | $ 38 | $ 3 | $ 92 |
| Three months ended June 30, 2021 | 54 | 36 | 9 | 99 |

Other costs of operations decreased by $7 million for the three months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | **(In millions)** |
|---|---|
| Decrease due to the sale of fossil generating assets to Generation Bridge in December 2021 | $ (8) |
| Increase in retail gross receipt taxes due to higher revenues | 5 |
| Other | (4) |
| Decrease in other cost of operations | $ (7) |

### *Depreciation and Amortization*

Depreciation and amortization are comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Corporate | Total |
|---|---|---|---|---|---|
| Three months ended June 30, 2022 | $ 77 | $ 50 | $ 22 | $ 8 | $ 157 |
| Three months ended June 30, 2021 | 84 | (56) | 18 | 7 | 53 |

Depreciation and amortization increased by $104 million for the three months ended June 30, 2022, compared to the same period in 2021, primarily due to adjustments to acquired intangibles in the second quarter of 2021 in connection with the acquisition of Direct Energy.

### *Impairment Losses*

Impairment losses of $155 million were recorded during the three months ended June 30, 2022 primarily related to the decline in PJM capacity prices and the near-term retirement date of Joliet. Impairment losses of $306 million were recorded during the three months ended June 30, 2021 related to the decline in capacity prices and the planned retirement of a significant portion of the PJM coal fleet. Refer to Note 8, *Impairments* for further discussion.

### *Selling, General and Administrative Costs*

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

| (In millions) | Texas | East | West/Services/ Other | Corporate | Eliminations | Total |
|---|---|---|---|---|---|---|
| Three months ended June 30, 2022 | $ 155 | $ 103 | $ 53 | $ 14 | $ — | $ 325 |
| Three months ended June 30, 2021 | 141 | 121 | 45 | 10 | — | 317 |

Selling, general and administrative costs increased by $8 million for the three months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | (In millions) |
|---|---|
| Decrease in transition service agreement costs related to the Direct Energy acquisition | $ (7) |
| Decrease due to Winter Storm Uri, primarily due to legal expenses and charitable giving in 2021 | (6) |
| Increase in broker fee expenses, partially offset by lower commissions expenses | 6 |
| Increase due to higher personnel costs | 4 |
| Increase in legal and consulting costs, including spending related to the Company's growth initiatives | 4 |
| Other | 7 |
| Increase in selling, general and administrative costs | $ 8 |

### *Provision for Credit Losses*

Provision for credit losses are comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Total |
|---|---|---|---|---|
| Three months ended June 30, 2022 | $ 9 | $ 11 | $ 6 | $ 26 |
| Three months ended June 30, 2021 | 40 | (2) | 2 | 40 |

Provision for credit losses decreased by $14 million for the three months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | (In millions) |
|---|---|
| Decrease due to Winter Storm Uri, including:<br>Decrease of $10 million related to bilateral financial hedging risk<br>Decrease of $11 million related to counterparty credit risk | $ (21) |
| Other | 7 |
| Decrease in provision for credit losses | $ (14) |

### *Acquisition-Related Transaction and Integration Costs*

Acquisition-related transaction and integration costs of $10 million were incurred during the three months ended June 30, 2022, which are comprised primarily of integration costs related to Direct Energy.

Acquisition-related transaction and integration costs of $22 million were incurred during the three months ended June 30, 2021, related to Direct Energy, of which $1 million were acquisition-related transaction costs and $21 million were integration costs primarily related to severance and consulting services.

### *Gain on Sale of Assets*

The gain on sale of assets of $32 million for the three months ended June 30, 2022 was due to a gain of $46 million related to the sale of the Company's 49% ownership in the Watson natural gas generating facility in June, partially offset by a loss of $14 million on other asset sales.

### *Interest Expense*

Interest expense decreased by $20 million for the three months ended June 30, 2022, compared to the same period in 2021, primarily due to debt reduction and the refinancing of debt to lower interest rates in the second half of 2021.

### *Income Tax Expense*

For the three months ended June 30, 2022, income tax expense of $152 million was recorded on pre-tax income of $665 million. For the same period in 2021, income tax expense of $380 million was recorded on pre-tax income of $1.5 billion. The effective tax rates were 22.9% and 26.1% for the three months ended June 30, 2022 and 2021, respectively.

For the three months ended June 30, 2022, the effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense, partially offset by tax benefit resulting from the release of valuation allowance on state net operating losses. For the same period in 2021, the effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense.

**Management's discussion of the results of operations for the six months ended June 30, 2022 and 2021**

***Electricity Prices***

The following table summarizes average on peak power prices for each of the major markets in which NRG operates for the six months ended June 30, 2022 and 2021. The average on-peak power prices decreased significantly in Texas due to Winter Storm Uri's impact on 2021 pricing. East and West average on-peak power prices increased for the six months ended June 30, 2022 as compared to the same period in 2021 as a result of higher natural gas prices.

| | Average on Peak Power Price ($/MWh) | | |
|---|---|---|---|
| | Six months ended June 30, | | |
| **Region** | **2022** | **2021** | **Change %** |
| Texas | | | |
| ERCOT - Houston [(a)] | $ 87.50 | $ 336.66 | (74)% |
| ERCOT - North[(a)] | 62.70 | 332.05 | (81)% |
| East | | | |
| NY J/NYC[(b)] | $ 92.79 | $ 40.18 | 131 % |
| NEPOOL[(b)] | 94.88 | 44.46 | 113 % |
| COMED (PJM)[(b)] | 64.73 | 32.82 | 97 % |
| PJM West Hub[(b)] | 75.66 | 34.40 | 120 % |
| West | | | |
| MISO - Louisiana Hub[(b)] | $ 67.73 | $ 37.69 | 80 % |
| CAISO - SP15[(b)] | 52.77 | 40.82 | 29 % |

(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 six months ended June 30, 2022 and 2021:

| | Average Realized Power Price ($/MWh) | | |
|---|---|---|---|
| | Six months ended June 30, | | |
| **Segment** | **2022** | **2021** | **Change %** |
| East[(a)] | $ 51.14 | $ 37.93 | 35 % |
| West/Services/Other | 54.86 | 33.71 | 63 % |

(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 ($5.83)/MWh in the six months ended June 30, 2022 and an immaterial amount in the six months ended June 30, 2021

The average realized power prices increased in the East and West/Services/Other segments for the six months ended June 30, 2022, as compared to the same period in 2021, 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 revenues less cost of fuel, purchased energy and 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 energy 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 six months ended June 30, 2022 and 2021:

| | Six months ended June 30, 2022 | | | | |
|---|---|---|---|---|---|
| **($ In millions)** | **Texas** | **East** | **West/Services/ Other** | **Corporate/ Eliminations** | **Total** |
| Retail revenue | $ 4,523 | $ 7,921 | $ 2,078 | $ (1) | $ 14,521 |
| Energy revenue | 53 | 332 | 185 | 14 | 584 |
| Capacity revenue | — | 204 | 2 | — | 206 |
| Mark-to-market for economic hedging activities | (3) | (236) | (56) | 14 | (281) |
| Contract amortization | — | (20) | (2) | — | (22) |
| Other revenue [a] | 146 | 33 | 1 | (10) | 170 |
| Total revenue | 4,719 | 8,234 | 2,208 | 17 | 15,178 |
| Cost of fuel | (529) | (175) | (157) | — | (861) |
| Purchased energy and other cost of sales[b][c][d] | (2,968) | (7,431) | (1,859) | (5) | (12,263) |
| Mark-to-market for economic hedging activities | 1,262 | 1,818 | 211 | (14) | 3,277 |
| Contract and emission credit amortization | 4 | (102) | (5) | — | (103) |
| Depreciation and amortization | (153) | (128) | (43) | (16) | (340) |
| **Gross margin** | **$ 2,335** | **$ 2,216** | **$ 355** | **$ (18)** | **$ 4,888** |
| Less: Mark-to-market for economic hedging activities, net | 1,259 | 1,582 | 155 | — | 2,996 |
| Less: Contract and emission credit amortization, net | 4 | (122) | (7) | — | (125) |
| Less: Depreciation and amortization | (153) | (128) | (43) | (16) | (340) |
| **Economic gross margin** | **$ 1,225** | **$ 884** | **$ 250** | **$ (2)** | **$ 2,357** |

(a) Includes trading gains and losses and ancillary revenues

(b) Includes capacity and emissions credits

(c) Includes $1.5 billion, $111 million and $664 million of TDSP expense in Texas, East, and West/Services/Other, 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) | 20,826 | 6,460 | 1,096 | | 28,382 |
| Business electricity sales volume (GWh) | 18,853 | 24,358 | 4,559 | | 47,770 |
| Home natural gas sales volume (MDth) | — | 52,839 | 53,618 | | 106,457 |
| Business natural gas sales volume (MDth) | — | 852,802 | 79,794 | | 932,596 |
| Average retail Home customer count (in thousands)[a][b] | 3,020 | 1,781 | 789 | | 5,590 |
| Ending retail Home customer count (in thousands)[a][b] | 3,008 | 1,808 | 785 | | 5,601 |
| **Power generation** | | | | | |
| GWh sold | 18,056 | 5,827 | 3,372 | | 27,255 |
| GWh generated [c] | | | | | |
| Coal | 9,316 | 3,827 | — | | 13,143 |
| Gas | 3,669 | 152 | 3,376 | | 7,197 |
| Nuclear | 5,071 | — | — | | 5,071 |
| Renewables | — | — | 5 | | 5 |
| Total | 18,056 | 3,979 | 3,381 | | 25,416 |

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

(b) The whole home warranty business was sold in January 2022

(c) Includes owned and leased generation, excludes tolled generation and equity investments

| ($ In millions) | Six months ended June 30, 2021 Texas | East | West/Services/ Other | Corporate/ Eliminations | Total |
|---|---|---|---|---|---|
| Retail revenue | $ 4,072 | $ 5,331 | $ 1,577 | $ (2) | $ 10,978 |
| Energy revenue | 299 | 227 | 125 | 2 | 653 |
| Capacity revenue | — | 396 | 30 | — | 426 |
| Mark-to-market for economic hedging activities | (4) | (50) | (54) | 6 | (102) |
| Contract amortization | — | (8) | (8) | — | (16) |
| Other revenue[(a)] | 1,360 | 29 | 11 | (5) | 1,395 |
| Total revenue | 5,727 | 5,925 | 1,681 | 1 | 13,334 |
| Cost of fuel | (938) | (62) | (64) | — | (1,064) |
| Purchased energy and other cost of sales[(b)(c)(d)] | (4,056) | (4,706) | (1,372) | 1 | (10,133) |
| Mark-to-market for economic hedging activities | 1,153 | 1,063 | 130 | (6) | 2,340 |
| Contract and emission credit amortization | 7 | (69) | (2) | — | (64) |
| Depreciation and amortization | (161) | (150) | (45) | (14) | (370) |
| **Gross margin** | **$ 1,732** | **$ 2,001** | **$ 328** | **$ (18)** | **$ 4,043** |
| Less: Mark-to-market for economic hedging activities, net | 1,149 | 1,013 | 76 | — | 2,238 |
| Less: Contract and emission credit amortization, net | 7 | (77) | (10) | — | (80) |
| Less: Depreciation and amortization | (161) | (150) | (45) | (14) | (370) |
| **Economic gross margin** | **$ 737** | **$ 1,215** | **$ 307** | **$ (4)** | **$ 2,255** |

(a) Includes trading gains and losses and ancillary revenues

(b) Includes capacity and emissions credits

(c) Includes $1.2 billion, $100 million and $535 million of TDSP expense in Texas, East, and West/Services/Other, 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) | 20,818 | 7,105 | 1,136 | | 29,059 |
| Business electricity sales volume (GWh) | 14,597 | 25,579 | 4,650 | | 44,826 |
| Home natural gas sales volume (MDth) | — | 47,929 | 55,619 | | 103,548 |
| Business natural gas sales volume (MDth) | — | 807,389 | 59,047 | | 866,436 |
| Average retail Home customer count (in thousands)[(a)(b)] | 3,079 | 1,897 | 973 | | 5,949 |
| Ending retail Home customer count (in thousands)[(a)(b)] | 3,027 | 1,869 | 967 | | 5,863 |
| **Power generation** | | | | | |
| GWh sold | 17,227 | 5,748 | 3,708 | | 26,683 |
| GWh generated [(c)] | | | | | |
| Coal | 8,631 | 2,537 | — | | 11,168 |
| Gas[(d)] | 4,081 | 575 | 3,635 | | 8,291 |
| Nuclear | 4,515 | — | — | | 4,515 |
| Oil[(e)] | — | 80 | — | | 80 |
| Total | 17,227 | 3,192 | 3,635 | | 24,054 |

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

(b) Includes 152 thousand whole home warranty customers in West/Services/Other. The whole home warranty business was sold in January 2022

(c) Includes owned and leased generation, excludes tolled generation and equity investments

(d) Includes 384 GWh and 920 GWh in East and West/Services/Other, respectively, that was sold to Generation Bridge in December 2021

(e) Includes 80 GWh in East that was sold to Generation Bridge in December 2021

The table below represents the weather metrics for the six months ended June 30, 2022 and 2021:

| | Six months ended June 30, | | |
|---|---|---|---|
| **Weather Metrics** | **Texas** | **East** | **West/Services/ Other [b]** |
| **2022** | | | |
| CDDs [a] | 1,351 | 393 | 705 |
| HDDs [a] | 1,202 | 2,890 | 1,344 |
| **2021** | | | |
| CDDs | 985 | 400 | 558 |
| HDDs | 1,202 | 2,891 | 1,393 |
| **10-year average** | | | |
| CDDs | 1,082 | 395 | 599 |
| HDDs | 1,001 | 2,868 | 1,245 |

(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 $845 million and economic gross margin increased $102 million, both of which include intercompany sales, during the six months ended June 30, 2022, compared to the same period in 2021.

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 driven by an increase in unhedgeable ancillary and operating reserve demand curve[a] | $ | 573 |
| **The following explanations exclude the impact of Winter Storm Uri:** | | |
| Lower gross margin due to the net effect of:<br>• a 41%, or $446 million increase in overall average costs to serve the retail load, driven by increases in power, ancillary, and fuel costs, extended outages at W.A. Parish Unit 8 and Limestone Unit 1, and the more conservative winter hedge profile in the first quarter of 2022, partially offset by the favorable impact of the early settlement of an online renewable PPA; and<br>• increased net revenue rates of $6.75 per MWh, or $225 million, and higher gross margin attributable to increased load of 1.4 million MWhs, or $39 million, both primarily driven by changes in customer mix | | (182) |
| Higher power gross margin due to an increase in load of 3.2 million MWhs due to weather | | 111 |
| Lower gross margin due to market optimization activities | | (14) |
| **Increase in economic gross margin** | $ | 488 |
| Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges | | 110 |
| Increase in contract and emission credit amortization | | (3) |
| Decrease in depreciation and amortization | | 8 |
| **Increase in gross margin** | **$** | **603** |

(a) For further discussion of ERCOT's securitization activity see *Regional Regulatory Developments* section under Energy Regulatory Matters above and Note 2, *Summary of Significant Accounting Policies*

*East*

| | | (In millions) |
|---|---|---|
| Lower 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:** | | |
| Lower gross margin due to the sale of fossil generating assets to Generation Bridge in December 2021 | | (117) |
| Lower power gross margin due to higher supply costs of $22.25 per MWh, driven primarily by increases in power prices, totaling $683 million, partially offset by higher net revenue rates as a result of changes in customer term, product and mix of $17.00 per MWh, or $522 million | | (161) |
| Lower power gross margin from decreased load due to attrition and customer mix | | (21) |
| Higher natural gas gross margin including the impact of transportation and storage contract optimization, resulting in higher net revenue rates from changes in customer term, product and mix of $2.75 per Dth, or $2.5 billion, partially offset by higher supply costs of $2.50 per Dth, or $2.4 billion. | | 155 |
| Higher natural gas gross margin from increased load due to customer mix, partially offset by attrition | | 17 |
| Lower demand response gross margin primarily from the reduction in early settlements of capacity obligations in 2022 of $88 million partially offset by curtailment program revenues of $4 million | | (84) |
| Higher gross margin due to a 59% increase in average realized pricing and an increase in generation volumes due to dark spread expansion primarily at Midwest Generation, partially offset by an increase in supply costs | | 48 |
| Lower gross margin driven by a 50% decrease in New York realized capacity prices | | (8) |
| Lower gross margin from market optimization activities | | (4) |
| Other | | (10) |
| **Decrease in economic gross margin** | $ | (331) |
| Increase in mark-to-market for economic hedging primarily due to net unrealized gains/losses on open positions related to economic hedges | | 569 |
| Increase in contract amortization | | (45) |
| Decrease in depreciation and amortization | | 22 |
| **Increase in gross margin** | **$** | **215** |

*West/Services/Other*

| | | (In millions) |
|---|---|---|
| Lower 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:** | | |
| Lower gross margin due to the sale of fossil generating assets to Generation Bridge in December 2021 | | (37) |
| Higher power gross margin due to an increase in net revenue rates as a result of changes in customer term, product and mix of $6.50 per MWh, or $30 million, and increased load due to changes in customer mix of $6 million, partially offset by higher supply costs of $1.50 per MWh, or $8 million, primarily due to increases in power prices | | 28 |
| Lower natural gas gross margin due to higher supply costs of $1.50 per Dth, or $204 million, partially offset by higher net revenue rates of $1.20 per Dth, or $152 million, and higher natural gas gross margin from increased load due to changes in customer mix, totaling $25 million | | (27) |
| Lower gross margin for the services business driven primarily by the sale of the whole home warranty business in the January 2022, partially offset by higher gross margin from the Airtron business | | (5) |
| Other | | (3) |
| **Decrease in economic gross margin** | $ | (57) |
| Increase in mark-to-market for economic hedges primarily due to net unrealized gains/losses on open positions related to economic hedges | | 79 |
| Decrease in contract amortization | | 3 |
| Decrease in depreciation and amortization | | 2 |
| **Increase in gross margin** | **$** | **27** |

***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 $758 million during the six months ended June 30, 2022, compared to the same period in 2021.

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

| | Six months ended June 30, 2022 | | | | |
|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **East** | **West/Services/ Other** | **Eliminations** | **Total** |
| **Mark-to-market results in revenue** | | | | | |
| Reversal of previously recognized unrealized losses/ (gains) on settled positions related to economic hedges | $ 1 | $ (21) | $ 36 | $ (4) | $ 12 |
| Reversal of acquired loss positions related to economic hedges | — | 1 | — | — | 1 |
| Net unrealized (losses) on open positions related to economic hedges | (4) | (216) | (92) | 18 | (294) |
| **Total mark-to-market (losses) in revenue** | $ (3) | $ (236) | $ (56) | $ 14 | $ (281) |
| **Mark-to-market results in operating costs and expenses** | | | | | |
| Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges | $ (145) | $ (396) | $ (80) | $ 4 | $ (617) |
| Reversal of acquired loss/(gain) positions related to economic hedges | 31 | (43) | (1) | — | (13) |
| Net unrealized gains on open positions related to economic hedges | 1,376 | 2,257 | 292 | (18) | 3,907 |
| **Total mark-to-market gains in operating costs and expenses** | $ 1,262 | $ 1,818 | $ 211 | $ (14) | $ 3,277 |

| | Six months ended June 30, 2021 | | | | |
|---|---|---|---|---|---|
| **(In millions)** | **Texas** | **East** | **West/Services/ Other** | **Eliminations** | **Total** |
| **Mark-to-market results in revenue** | | | | | |
| Reversal of previously recognized unrealized (gains) on settled positions related to economic hedges | $ (1) | $ (19) | $ (4) | $ (1) | $ (25) |
| Reversal of acquired (gain) positions related to economic hedges | — | (4) | — | — | (4) |
| Net unrealized (losses) on open positions related to economic hedges | (3) | (27) | (50) | 7 | (73) |
| **Total mark-to-market (losses) in revenue** | $ (4) | $ (50) | $ (54) | $ 6 | $ (102) |
| **Mark-to-market results in operating costs and expenses** | | | | | |
| Reversal of previously recognized unrealized losses/ (gains) on settled positions related to economic hedges | $ 63 | $ 2 | $ (2) | $ 1 | $ 64 |
| Reversal of acquired loss positions related to economic hedges | 67 | 171 | 14 | — | 252 |
| Net unrealized gains on open positions related to economic hedges | 1,023 | 890 | 118 | (7) | 2,024 |
| **Total mark-to-market gains in operating costs and expenses** | $ 1,153 | $ 1,063 | $ 130 | $ (6) | $ 2,340 |

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

For the six months ended June 30, 2022, the $281 million loss in revenues from economic hedge positions was driven by a decrease in the value of open positions as a result of increases in PJM power prices, partially offset by the reversal of previously recognized unrealized losses on contracts that settled during the period. The $3.3 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, partially offset by the reversal of previously recognized unrealized gains on contracts that settled during the period.

For the six months ended June 30, 2021, the $102 million loss in revenues from economic hedge positions was driven by a decrease in the value of open positions as a result of increases in power prices across all segments as well as the reversal of previously recognized unrealized gains on contracts that settled during the period. The $2.3 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.

In accordance with ASC 815, the following table represents the results of the Company's financial and physical trading of energy commodities for the six months ended June 30, 2022 and 2021. The realized and unrealized financial and physical trading results are included in revenue. The Company's trading activities are subject to limits based on the Company's Risk Management Policy.

| | Six months ended June 30, | |
|---|---|---|
| (In millions) | 2022 | 2021 |
| **Trading gains/(losses)** | | |
| Realized | $ 2 | $ 68 |
| Unrealized | (16) | (6) |
| Total trading (losses)/gains | $ (14) | $ 62 |

***Operations and Maintenance Expense***

Operations and maintenance expense are comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Corporate | Eliminations | Total |
|---|---|---|---|---|---|---|
| Six months ended June 30, 2022 | $ 385 | $ 215 | $ 92 | $ — | $ (2) | $ 690 |
| Six months ended June 30, 2021 | 364 | 224 | 117 | 2 | (3) | 704 |

Operations and maintenance expense decreased by $14 million for the six months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | (In millions) |
|---|---|
| Decrease due to the sale of fossil generating assets to Generation Bridge in December 2021 | $ (51) |
| Decrease driven by current year scrap material proceeds associated with the demolition of the Encina site | (8) |
| Decrease due to spare parts inventory reserves recorded in 2021 driven by announced retirements of certain PJM coal assets | (5) |
| Decrease driven by higher maintenance in 2021 resulting from the impacts of Winter Storm Uri | (2) |
| Increase in variable operation and maintenance expense at the PJM coal facilities associated with increased generation in 2022 as compared to 2021 | 22 |
| Increase in estimate of environmental remediation costs at a deactivated site in the East | 19 |
| Increase driven by higher retail operations costs | 7 |
| Other | 4 |
| Decrease in operations and maintenance expense | $ (14) |

***Other Cost of Operations***

Other Cost of operations are comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Total |
|---|---|---|---|---|
| Six months ended June 30, 2022 | $ 93 | $ 75 | $ 9 | $ 177 |
| Six months ended June 30, 2021 | 97 | 72 | 11 | 180 |

Other cost of operations decreased by $3 million for the six months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | (In millions) |
|---|---|
| Decrease due to the sale of fossil generating assets to Generation Bridge in December 2021 | $ (16) |
| Increase in retail gross receipt taxes due to higher revenues | 11 |
| Increase due to changes in current year ARO cost estimates and the timing of ARO spend | 4 |
| Other | (2) |
| Decrease in other cost of operations | $ (3) |

### *Depreciation and Amortization*

Depreciation and amortization expenses are comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Corporate | Total |
|---|---|---|---|---|---|
| Six months ended June 30, 2022 | $ 153 | $ 128 | $ 43 | $ 16 | $ 340 |
| Six months ended June 30, 2021 | 161 | 150 | 45 | 14 | 370 |

Depreciation and amortization decreased by $30 million for the six months ended June 30, 2022, compared to the same period in 2021, primarily due to lower amortization of acquired intangibles.

### *Impairment Losses*

Impairment losses of $155 million were recorded during the six months ended June 30, 2022 primarily related to the decline in PJM capacity prices and the near-term retirement date of Joliet. Impairment losses of $306 million were recorded during the six months ended June 30, 2021 related to the decline in capacity prices and the planned retirement of a significant portion of the PJM coal fleet. Refer to Note 8, *Impairments* for further discussion.

### *Selling, General and Administrative Costs*

Selling, general and administrative costs comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Corporate | Eliminations | Total |
|---|---|---|---|---|---|---|
| Six months ended June 30, 2022 | $ 299 | $ 220 | $ 102 | $ 26 | $ — | $ 647 |
| Six months ended June 30, 2021 | 286 | 262 | 86 | 21 | (1) | 654 |

Selling, general and administrative costs decreased by $7 million for the six months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | (In millions) |
|---|---|
| Decrease due to Winter Storm Uri, including charitable giving, legal and other costs of $15 million and ERCOT default charges of $12 million in 2021 | $ (27) |
| Decrease in transition service agreement costs related to the Direct Energy acquisition | (13) |
| Increase in legal and consulting costs, including spending related to the Company's growth initiatives | 13 |
| Increase in broker fee expenses, partially offset by lower commissions expenses. | 10 |
| Increase due to higher personnel costs | 4 |
| Other | 6 |
| Decrease in selling, general and administrative costs | $ (7) |

### *Provision for Credit Losses*

Provision for credit losses are comprised of the following:

| (In millions) | Texas | East | West/Services/ Other | Total |
|---|---|---|---|---|
| Six months ended June 30, 2022 | $ 12 | $ 25 | $ 14 | $ 51 |
| Six months ended June 30, 2021 | 642 | 4 | 5 | 651 |

Provision for credit losses decreased by $600 million for the six months ended June 30, 2022, compared to the same period in 2021, due to the following:

| | (In millions) |
|---|---|
| Decrease due to Winter Storm Uri, including:<br>Decrease of $403 million related to bilateral financial hedging risk<br>Decrease of $120 million related to counterparty credit risk<br>Decrease of $83 million related to ERCOT default shortfall payments | $ 606 |
| Other | (6) |
| Increase in provision for credit losses | $ 600 |

### *Acquisition-Related Transaction and Integration Costs*

Acquisition-related transaction and integration costs were $18 million for the six months ended June 30, 2022, which were primarily integration costs related to Direct Energy. Acquisition-related transaction and integration costs of $64 million were incurred during the six months ended June 30, 2021, related to Direct Energy, of which $23 million were acquisition-related transaction costs and $41 million were integration costs, primarily related to severance and consulting services.

### *Gain on Sale of Assets*

The gain on sale of assets of $29 million for the six months ended June 30, 2022 was due to the $46 million gain related to the sale of the Company's 49% ownership in the Watson natural gas generating facility in the second quarter, partially offset by a loss of $14 million on other asset sales and a $3 million adjustment to the proceeds on the sale of fossil generating assets to Generation Bridge in December of 2021. The gain on sale of assets of $17 million for the six months ended June 30, 2021 was related to the sale of Agua Caliente in February 2021.

### *Interest Expense*

Interest expense decreased by $44 million for the six months ended June 30, 2022, compared to the same period in 2021, primarily due to debt reduction and the refinancing of debt to lower interest rates in the second half of 2021.

### *Income Tax Expense*

For the six months ended June 30, 2022, income tax expense of $723 million was recorded on pre-tax income of $3.0 billion. For the same period in 2021, income tax expense of $295 million was recorded on pre-tax income of $1.3 billion. The effective tax rates were 24.3% and 22.9% for the six months ended June 30, 2022 and 2021, respectively.

For the six months ended June 30, 2022, NRG's overall effective tax rate was higher than the statutory rate of 21% primarily due to state tax expense, partially offset by tax benefit resulting from the release of valuation allowance on state net operating losses. For the same period in 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.

## Liquidity and Capital Resources

### *Liquidity Position*

As of June 30, 2022 and December 31, 2021, NRG's total liquidity, excluding funds deposited by counterparties, of approximately $3.1 billion and $2.7 billion, respectively, was comprised of the following:

| (In millions) | June 30, 2022 | December 31, 2021 |
|---|---|---|
| Cash and cash equivalents | $ 580 | $ 250 |
| Restricted cash - operating | 4 | 4 |
| Restricted cash - reserves(a) | 40 | 11 |
| Total | 624 | 265 |
| Total availability under Revolving Credit Facility and collective collateral facilities(b) | 2,460 | 2,421 |
| Total liquidity, excluding funds deposited by counterparties | $ 3,084 | $ 2,686 |

(a) Includes reserves primarily for performance obligations

(b) Total capacity of Revolving Credit Facility and collective collateral facilities was $6.2 billion and $5.9 billion as of June 30, 2022 and December 31, 2021, respectively

For the six months ended June 30, 2022, total liquidity, excluding funds deposited by counterparties, increased by $398 million. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading *Cash Flow Discussion*. Cash and cash equivalents at June 30, 2022 were predominantly held in bank deposits.

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.

The Company remains committed to maintaining a strong balance sheet and continues to work to achieve investment grade credit metrics. The Company expects to grow into its target investment grade metrics primarily through the realization of Direct Energy run-rate earnings and other growth initiatives.

***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; as described more fully in Note 9, *Long-term Debt and Finance Leases* (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, as described in Note 11, *Changes in Capital Structure*.

*ERCOT Securitization Proceeds*

During 2021, the Texas Legislature passed HB 4492 for ERCOT to mitigate exceptionally high price adders and ancillary service costs incurred by LSEs during Winter Storm Uri. HB 4492 authorized ERCOT to obtain $2.1 billion of financing to distribute to LSEs that were charged and paid to ERCOT those highly priced ancillary service and ORDPA during Winter Storm Uri. The Company received proceeds of $689 million from ERCOT in June 2022.

*Receivables Securitization Facilities*

On February 9, 2022, the Company entered into amendments to its existing Repurchase Facility to, among other things, (i) increase the size of the facility from $75 million to $150 million and (ii) replace LIBOR with term SOFR as the benchmark for the pricing rate. The Repurchase Facility has no commitment fee and borrowings will be drawn at SOFR + 1.30%. On July 26, 2022, the Company renewed its existing Repurchase Facility to extend the maturity date to July 26, 2023. As of June 30, 2022, there were no outstanding borrowings.

On July 26, 2022, NRG Receivables LLC, a wholly-owned indirect subsidiary of the Company, entered into an amendment to its Receivables Facility dated September 22, 2020 with a group of conduit lenders and banks and Royal Bank of Canada, as Administrative Agent to, among other things, (i) increase the facility size up to $1.0 billion, (ii) extend the scheduled termination date by one year, (iii) add new originators, (iv) replace LIBOR with Term SOFR as the benchmark for borrowings and (v) increase the letter of credit sublimit to equal the aggregate commitments. The weighted average interest rate related to usage under the Receivables Facility as of June 30, 2022 was 0.726%. As of June 30, 2022, there were no outstanding borrowings and there were $400 million in letters of credit issued under the Receivables Facility.

*Bilateral Letter of Credit Facilities*

On April 29, 2022 and May 27, 2022, the Company increased the size of the facilities by $100 million and $50 million, respectively, to provide additional liquidity, allowing for the issuance of up to $625 million of letters of credit. As of June 30, 2022, $608 million was issued under these facilities.

*Sale of Watson*

On June 1, 2022, the Company closed on the sale of its 49% ownership in the Watson natural gas generating facility to Tesoro Refining & Marketing Company LLC for $59 million. NRG recognized a gain on the sale of $46 million.

*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 related to certain 2019 employer payroll taxes is 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 (e.g., buying energy before receiving retail revenues); and (iv) initial collateral for large structured transactions. As of June 30, 2022, the Company had total cash collateral outstanding of $295 million and $3.7 billion outstanding in letters of credit to third parties primarily to support its market activities. As of June 30, 2022, total funds deposited by counterparties were $3.97 billion in cash and $745 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. 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 differ from the hedged prices. As of June 30, 2022, 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 June 30, 2022:

| **Equivalent Net Sales Secured by First Lien Structure**[a] | **2022** | **2023** |
|---|---|---|
| In MW | 447 | 664 |
| As a percentage of total net coal and nuclear capacity[b] | 13% | 15% |

(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 six months ended June 30, 2022, and the estimated capital expenditures forecast for the remainder of 2022.

| **(In millions)** | **Maintenance** | **Environmental** | **Growth Investments**[a] | **Total** |
|---|---|---|---|---|
| Texas | $ (87) | $ (1) | $ (20) | $ (108) |
| East | (2) | — | (3) | (5) |
| West/Services/Other | (11) | — | (1) | (12) |
| Corporate | (1) | — | (24) | (25) |
| Total cash capital expenditures for the six months ended June 30, 2022 | (101) | (1) | (48) | (150) |
| Investments | — | — | (67) | (67) |
| Total capital expenditures and investments | (101) | (1) | (115) | (217) |
| | | | | |
| Estimated capital expenditures and investments for the remainder of 2022[b] | $ (226) | $ (7) | $ (88) | $ (321) |

(a) Includes other investments, acquisitions and integration projects
(b) Estimated capital expenditures related to W.A. Parish do not reflect expected insurance recoveries

Growth investments for the six months ended June 30, 2022 include expenditures for Encina site improvements classified as ARO payments. Demolition is underway and is expected to be completed in the third quarter of 2022. The Company expects to begin marketing the site in the second half of the year.

*Environmental Capital Expenditures*

NRG estimates that environmental capital expenditures from 2022 through 2026 required to comply with environmental laws will be approximately $56 million, primarily driven by the cost of complying with ELG at the Company's coal units in Texas.

*Share Repurchases*

In December 2021, the Company's board of directors authorized the Company to repurchase $1.0 billion of its common stock, of which $44 million was completed in 2021. During the first half of 2022, the Company completed $361 million of share repurchases at an average price of $39.48 per share, including $6 million of equivalent shares purchased in lieu of tax withholdings on equity compensation issuances.

*Common Stock Dividends*

During the first quarter of 2022, NRG increased the annual dividend to $1.40 from $1.30 per share and expects to target an annual dividend growth rate of 7%-9% per share in subsequent years. A quarterly dividend of $0.35 per share was paid on the Company's common stock during the three months ended June 30, 2022. On July 20, 2022, NRG declared a quarterly dividend on the Company's common stock of $0.35 per share, payable on August 15, 2022 to stockholders of record as of August 1, 2022.

**Obligations under Certain Guarantees**

NRG and its subsidiaries enter into various contracts that include indemnifications and guarantee provisions as a routine part of the Company's business activities. For further discussion, see Note 27, *Guarantees,* to the Company's 2021 Form 10-K.

**Obligations Arising Out of a Variable Interest in an Unconsolidated Entity**

*Variable interest in equity investments* — As of June 30, 2022, 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 $524 million as of June 30, 2022. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG. See also Note 17, *Investments Accounted for by the Equity Method and Variable Interest Entities,* to the Company's 2021 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 2021 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 six months ended June 30, 2022.

**Cash Flow Discussion**

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

| | Six months ended June 30, | | |
|---|---|---|---|
| **(In millions)** | **2022** | **2021** | **Change** |
| Cash provided by operating activities | $ 3,189 | $ 377 | $ 2,812 |
| Cash used by investing activities | (119) | (3,492) | 3,373 |
| Cash provided by financing activities | 414 | 93 | 321 |

***Cash provided by operating activities***

Changes to 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 | $ 2,425 |
| Increase in working capital primarily attributable to the impact of higher market prices on accounts receivable and accounts payable, partially offset by a decrease in inventory | 478 |
| Decrease in working capital primarily due to timing of sales and use tax prepayments | (87) |
| Increase in operating income adjusted for other non-cash items | 54 |
| Decrease in other working capital primarily due to the impact of Winter storm Uri | (58) |
| | $ 2,812 |

***Cash used by investing activities***

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

| | (In millions) |
|---|---|
| Decrease in cash paid for acquisitions primarily due to the Direct Energy acquisition in 2021 | $ 3,468 |
| Decrease in proceeds from sale of assets primarily due to the sale of Agua Caliente in 2021 | (102) |
| Increase in proceeds from sales of investments in nuclear decommissioning trust fund securities, net of purchases | 34 |
| Increase in purchases of emissions allowances, net of sales | (20) |
| Increase in capital expenditures | (7) |
| | $ 3,373 |

***Cash provided by financing activities***

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

| | (In millions) |
|---|---|
| Increase in net receipts from settlement of acquired derivatives | $ 759 |
| Increase in payments for share repurchase activity | (357) |
| Decrease in proceeds from Revolving Credit Facility and Receivables Securitization Facilities | (75) |
| Increase in payments of dividends to common stockholders | (9) |
| Other | 3 |
| | $ 321 |

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

For the six months ended June 30, 2022, the Company had domestic pre-tax book income of $2.9 billion and foreign pre-tax book income of $37 million. As of December 31, 2021, the Company had cumulative U.S. Federal NOL carryforwards of $8.4 billion, of which $11 million were generated prior to Tax Cuts and Jobs Act and will begin expiring in 2031, and cumulative state NOL carryforwards of $5.2 billion for financial statement purposes. NRG also has cumulative foreign NOL carryforwards of $383 million, which do not have an expiration date. In addition to the above NOLs, NRG has a $20 million indefinite carryforward for interest deductions, as well as $384 million of tax credits to be utilized in future years. As a result of the Company's tax position, including the utilization of federal and state NOLs, and based on current forecasts, the Company anticipates net income tax payments, due to federal, state and foreign jurisdictions, of up to $50 million in 2022.

As of June 30, 2022, the Company has $19 million of tax-effected uncertain federal and state tax benefits, for which the Company has recorded a non-current tax liability of $20 million (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 Canadian income tax examinations are no longer open for years prior to 2013.

***Deferred tax assets and valuation allowance***

*Net deferred tax balance* — As of June 30, 2022 and December 31, 2021, NRG recorded a net deferred tax asset, excluding valuation allowance, of $1.6 billion and $2.3 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 June 30, 2022 as discussed below.

*NOL Carryforwards* — As of June 30, 2022, the Company had a tax-effected cumulative U.S. NOLs consisting of carryforwards for federal and state income tax purposes of $1.8 billion and $328 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 $100 million with no expiration date.

*Valuation Allowance* — As of June 30, 2022 and December 31, 2021, the Company’s tax-effected valuation allowance was $212 million and $248 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.

**Guarantor Financial Information**

As of June 30, 2022, the Company's outstanding registered senior notes consisted of $375 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) | Six months ended June 30, 2022 | Six months ended June 30, 2021 |
|---|---|---|
| Revenues[(a)] | $ 13,314 | $ 11,779 |
| Operating income[(b)] | 3,388 | 1,805 |
| Total other expense | (174) | (208) |
| Income from continuing operations before income taxes | 3,214 | 1,597 |
| Net Income | 2,499 | 1,320 |

(a) Intercompany transactions with Non-Guarantors of $175 million and $38 million during the six months ended June 30, 2022 and 2021, respectively

(b) Intercompany transactions with Non-Guarantors including cost of operations of $(175) million and $(98) million and selling, general and administrative of $77 million and $38 million during the six months ended June 30, 2022 and 2021, respectively

The following table presents the summarized balance sheet information:

| (In millions) | June 30, 2022 | December 31, 2021 |
|---|---|---|
| Current assets[(a)] | $ 19,364 | $ 9,399 |
| Property, plant and equipment, net | 1,295 | 1,324 |
| Non-current assets | 12,523 | 11,569 |
| Current liabilities[(b)] | 16,167 | 7,590 |
| Non-current liabilities | 12,144 | 11,195 |

(a) Includes intercompany receivables due from Non-Guarantors of $75 million and $86 million as of June 30, 2022 and December 31, 2021, respectively

(b) Includes intercompany payables due from Non-Guarantors of $139 million and $50 million as of June 30, 2022 and December 31, 2021, respectively

**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 primarily 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 June 30, 2022, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at June 30, 2022. 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 Gains/(Losses)** | **(In millions)** |
|---|---|
| Fair Value of Contracts as of December 31, 2021 | $ 2,341 |
| Contracts realized or otherwise settled during the period | (617) |
| Changes in fair value | 3,582 |
| Fair Value of Contracts as of June 30, 2022 | $ 5,306 |

| (In millions) | Fair Value of Contracts as of June 30, 2022 | | | | |
|---|---|---|---|---|---|
| | 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 | $ 658 | $ 477 | $ 57 | $ 10 | $ 1,202 |
| Level 2 | 1,683 | 717 | 189 | 112 | 2,701 |
| Level 3 | 982 | 255 | 43 | 123 | 1,403 |
| Total | $ 3,323 | $ 1,449 | $ 289 | $ 245 | $ 5,306 |

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 June 30, 2022, NRG's net derivative asset was $5.3 billion, an increase to total fair value of $3.0 billion as compared to December 31, 2021. This increase was primarily driven by gains in fair value, partially offset by roll-off of trades that settled during the period.

Based on a sensitivity analysis using simplified assumptions, the impact of a $0.50 per MMBtu increase in natural gas prices across the term of the derivative contracts would result in an increase of approximately $1.4 billion in the net value of derivatives as of June 30, 2022.

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 $1.5 billion in the net value of derivatives as of June 30, 2022.

**Critical Accounting 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 appropriate technical accounting rules and guidance involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and the fair value of certain assets and liabilities. These judgments, in and of themselves, could materially affect the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may also have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies has not changed.

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

The Company identifies its most critical accounting estimates 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.

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 2021 Form 10-K. There have been no material changes to the Company's critical accounting estimates since the 2021 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 retail operations, 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, credit risk, liquidity 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 2021 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 load serving obligations and merchant generation operations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales and purchases of energy 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 six months ending June 30, 2022 and 2021:

| (In millions) | 2022 | 2021 |
|---|---|---|
| **VaR as of June 30,[(a)]** | $ 35 | $ 41 |
| Three months ended June 30, | | |
| Average[(b)] | $ 53 | $ 32 |
| Maximum[(b)] | 86 | 46 |
| Minimum[(b)] | 30 | 26 |
| Six months ended June 30, | | |
| Average[(b)] | $ 45 | $ 31 |
| Maximum[(b)] | 86 | 46 |
| Minimum[(b)] | 27 | 25 |

(a) Calculation includes entire NRG portfolio as of March 31, 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 $579 million, as of June 30, 2022, primarily driven by asset-backed and hedging transactions.

***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. Counterparty credit risk and retail customer credit risk are discussed below. See Note 7, *Accounting for Derivative Instruments and Hedging Activities*, to this Form 10-Q for discussion regarding credit risk contingent features.

***Counterparty Credit Risk***

The Company's counterparty credit risk policies are disclosed in its 2021 Form 10-K. As of June 30, 2022, counterparty credit exposure, excluding credit exposure from RTOs, ISOs, registered commodity exchanges and certain long-term agreements, was $3.9 billion and NRG held collateral (cash and letters of credit) against those positions of $2.5 billion, resulting in a net exposure of $1.5 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 80% of the Company's exposure before collateral is expected to roll off by the end of 2023. 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 | 78 % |
| Financial institutions | 22 |
| Total as of June 30, 2022 | 100 % |

| **Category by Counterparty Credit Quality** | **Net Exposure [(a)(b)] (% of Total)** |
|---|---|
| Investment grade | 52 % |
| Non-investment grade/non-rated | 48 |
| Total as of June 30, 2022 | 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 exposure to one wholesale counterparty in excess of 10% of total net exposure discussed above as of June 30, 2022. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration.

During the first quarter of 2021, during Winter Storm Uri, the Company experienced a 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 obligations under this transaction but, given the size of the exposure and the counterparty filing for Chapter 11 bankruptcy protection, cannot determine with certainty what the amount of its ultimate recovery will be. The full exposure was provided for in the allowance for credit losses since March 31, 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 June 30, 2022, aggregate credit risk exposure managed by NRG to these counterparties was approximately $1.1 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 June 30, 2022, 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. Current economic conditions may affect the Company's customers' ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in credit losses.

***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 June 30, 2022, 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 $954 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 $434 million. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of June 30, 2022.

***Interest Rate Risk***

As of June 30, 2022, the fair value and related carrying value of the Company's debt was $7.2 billion and $8.1 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 June 30, 2022 by $541 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 June 30, 2022, NRG is exposed to changes in foreign currency primarily 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 $405 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 June 30, 2022 would have resulted in an increase of $3 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 June 30, 2022 that materially affected, or are reasonably likely to materially affect, NRG's internal control over financial reporting.

## PART II — OTHER INFORMATION

### ITEM 1 — LEGAL PROCEEDINGS

For a discussion of material legal proceedings in which NRG was involved through June 30, 2022, see Note 16, *Commitments and Contingencies*, to this Form 10-Q.

### ITEM 1A — RISK FACTORS

During the six months ended June 30, 2022, there were no material changes to the Risk Factors disclosed in Part I, Item 1A, *Risk Factors,* of the Company's 2021 Form 10-K, except for the update below:

***Negative publicity may damage NRG's reputation or its brands.***

NRG's reputation and brands could be damaged for numerous reasons, including negative views of the Company's environmental impact, sustainability goals, supply chain practices, product and service offerings, sponsorship relationships, charitable giving programs and public statements made by Company officials. The Company may also experience criticism or backlash from media, customers, employees, government entities, advocacy groups and other stakeholders that disagree with positions taken by the Company or its executives. If the Company's brands or reputation are damaged, it could negatively impact the Company's business, financial condition, results of operations, and ability to attract and retain highly qualified employees.

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

The table below sets forth the information with respect to purchases made by or on behalf of NRG or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act), of NRG's common stock during the quarter ended June 30, 2022.

| For the three months ended March 31, 2022 | Total Number of Shares Purchased | Average Price Paid per Share(b) | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(a)(c) |
|---|---|---|---|---|
| Month #1 | | | | |
| (April 1, 2022 to April 30, 2022 | 2,014,734 | $ 37.99 | 2,014,734 | $ 686,349,234 |
| Month #2 | | | | |
| (May 1, 2022 to May 31, 2022) | 1,672,909 | $ 41.61 | 1,672,909 | $ 616,697,794 |
| Month #3 | | | | |
| (June 1, 2022 to June 30, 2022) | 480,000 | $ 45.59 | 480,000 | $ 594,752,895 |
| Total at June 30, 2022 | 4,167,643 | $ 40.32 | 4,167,643 | |

(a) On December 6, 2021 the Company announced that the Board of Directors has authorized $1 billion for share repurchases, as part of NRG's capital allocation program. The program began in December 2021 and continues in 2022

(b) The average price paid per share excludes commissions of $0.02 per share paid in connection with the open market share repurchases

(c) Includes commissions of $0.02 per share paid in connection with the open market share repurchases

### ITEM 3 — DEFAULTS UPON SENIOR SECURITIES

None.

### ITEM 4 — MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Form 10-Q

### ITEM 5 — OTHER INFORMATION

None.

## ITEM 6 — EXHIBITS

| Number | Description | Method of Filing |
|---|---|---|
| 10.1 | Amendment No. 2 to Receivables Loan and Servicing Agreement, dated as of July 26, 2022, among NRG Retail LLC, as Servicer, NRG Receivables LLC, as Borrower, NRG Energy, Inc., as Performance Guarantor, the Conduit Lenders, Committed Lenders, Facility Agents and LC Issuers party thereto, and Royal Bank of Canada, as administrative Agent, and included as Exhibit A-2 thereto a clean, conformed copy of the Receivables Loan and Servicing Agreement. | Incorporated herein by reference to Exhibit 10.1 to the Registrant's current report on Form 8-K filed on August 1, 2022. |
| 10.2 | Joinder Agreement, dated as of July 26, 2022, by Direct Energy, LP, as an additional originator, and consented to by NRG Receivables LLC, as Borrower, NRG Retail LLC, as Servicer, and Royal Bank of Canada, as administrative agent, to the Receivables Sale Agreement, dated as of September 22, 2020, among the Originators from time to time parties thereto, NRG Retail LLC, as Servicer, and NRG Receivables LLC. | Incorporated herein by reference to Exhibit 10.2 to the Registrant's current report on Form 8-K filed on August 1, 2022. |
| 10.3 | Joinder Agreement, dated as of July 26, 2022, by Direct Energy Business, LLC, as an additional originator and consented to by NRG Receivables LLC, as Borrower, NRG Retail LLC, as Servicer, and Royal Bank of Canada, as administrative agent, to the Receivables Sale Agreement, dated as of September 22, 2020, among the Originators from time to time parties thereto, NRG Retail LLC, as Servicer, and NRG Receivables LLC. | Incorporated herein by reference to Exhibit 10.3 to the Registrant's current report on Form 8-K filed on August 1, 2022. |
| 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 Emily Picarello. | Filed herewith. |
| 32 | Section 1350 Certification. | Furnished herewith. |
| 95.1 | Mine Safety Disclosure | Filed 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/ EMILY PICARELLO
Emily Picarello
*Corporate Controller*
*(Principal Accounting Officer)*

Date: August 4, 2022