VISTRA ENERGY

2018 Annual Report

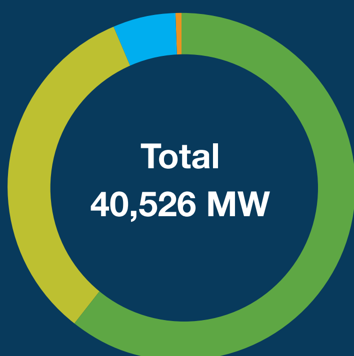
Diversified, Integrated Operations

Vistra Energy is a premier, integrated power company, combining an innovative, customer-centric approach to retail with a focus on safe, reliable, and efficient power generation. Through our retail and generation businesses, which include TXU Energy, Homefield Energy, Dynegy, and Luminant, Vistra operates in 12 states. Our retail brands serve approximately 2.9 million residential, commercial, and industrial customers across five top retail states, and our generation fleet totals approximately 41,000 megawatts of highly efficient generation capacity, with a diverse portfolio of natural gas, nuclear, coal, solar, and battery storage facilities.

2018 Retail Volumes

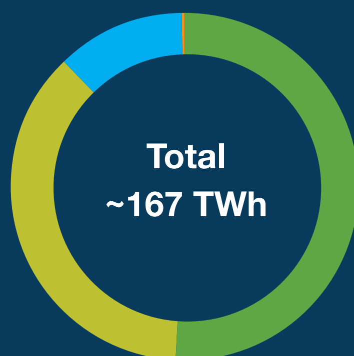
Residential	34%
Business	52%
Muni-Aggregation	14%

2018 Generating Capacity



Gas	61%
Coal	33%
Nuclear	6%
Solar	0.4%

2018 Energy Production [(1)]



Gas	51%
Coal	37%
Nuclear	12%
Solar	0.2%

(1) Excludes purchased power

> We believe the combination of our industry-leading retail business, in-the-money generation fleet, and advanced commercial operations is continuing to prove out its stable earnings profile and ability to generate significant free cash flow.

Curt Morgan
President and Chief Executive Officer

Dear Fellow VST Stockholders,

2018 was a transformative year for Vistra Energy Corp. as we closed our merger with Dynegy in April, hosted our first Analyst Day in June, announced our near-term capital allocation plan, and executed on various growth and business development opportunities. We continued to demonstrate the strength of the new integrated model—a business centered on low-leverage, low-cost retail and wholesale operations with a focus on commercial optimization and capital allocation, including returning capital to stockholders and prudent investment in the business.

We believe the combination of our industry-leading retail business, in-the-money generation fleet, and advanced commercial operations is continuing to prove out its stable earnings profile and ability to generate significant free cash flow. Vistra is forecasting it will deliver more than $3 billion in adjusted EBITDA from its ongoing operations in 2019 with an adjusted EBITDA to adjusted free cash flow conversion ratio of approximately 66 percent. We are also committed to returning capital to stockholders, as evidenced by the capital allocation plan we announced in October 2018. Our capital allocation plan includes authorization for up to $1.75 billion in share repurchases, more than half of which we have executed as of February 2019; the initiation of an annual dividend program, which paid its first quarterly dividend in March of this year; and a commitment to achieve our long-term leverage target of 2.5 times net debt to EBITDA by year-end 2020.

Vistra has also proven it can selectively and prudently deploy capital into the business and create significant stockholder value as evidenced by the Dynegy merger, the acquisition of the Odessa power plant, and the Upton 2 solar and battery projects. In addition, in 2019, we have announced an agreement to acquire Crius Energy Trust, which will expand our retail presence to 19 states and the District of Columbia, accelerating our Midwest and Northeast growth strategy while establishing a platform for future growth, including broadening our retail product offerings into natural gas. This investment, at an estimated 4.0 times enterprise value to EBITDA, is an example of our disciplined approach to growth opportunities, meeting our internal investment threshold while being immediately accretive to EBITDA and free cash flow. We expect the transaction will close in second quarter of 2019, and we are excited about the strategic fit of the Crius portfolio with Vistra's existing retail and generation platform.

Vistra Energy hosted its first Analyst Day at its Irving, Texas headquarters on June 12, 2018.

Our success in 2018 and positive outlook for the year ahead are a direct result of the relentless focus and dedication to excellence Vistra achieved as "One Company, One Team" in 2018. I am pleased to discuss some of the highlights from the past year with you in the paragraphs that follow.

Dynegy Integration and Synergy Capture

We closed our merger with Dynegy in April 2018, creating the lowest-cost integrated power company in the industry with leading retail and generation operations in the key competitive power markets in the United States. Importantly, we were able to complete the merger without any required divestiture of any of our ERCOT gas-fueled power plants. Vistra Energy now operates in 12 states, serving approximately 240,000 commercial and industrial customers and 2.7 million residential customers in five top retail states with retail sales of approximately 74 terawatt hours. Vistra also owns approximately 41 gigawatts of installed generation capacity—more than 60 percent of which is natural gas-fueled and more than 80 percent of which is located in the ERCOT, PJM, and ISO-NE competitive power markets.

The Dynegy integration and synergy capture has touched every part of our company. Significant work completed before and continued after the close of the merger allowed us to immediately integrate our businesses on Day 1 and begin the synergy capture with minimal disruption. We communicated an expectation to achieve $225 million per year of ongoing EBITDA synergies when we announced the merger in October 2017, and we are now targeting $290 million of announced EBITDA synergies—a nearly 30 percent increase.

Similarly, at the time we announced the merger we identified a substantial opportunity to capture operational improvements through our Operations Performance Improvement ("OPI") program. We initially announced an expectation to achieve $125 million of annual OPI EBITDA enhancements, and we have since more than doubled that target to $275 million per year. Notably, we still see the potential for upside to this target as we continue to execute in 2019. The success of this program is due to many initiatives across the entire fleet of assets with nearly 100 percent involvement from plant employees and a very detailed governance and tracking system to ensure capture. The OPI initiative, which is designed to ensure our generation fleet is operating as efficiently and cost-effectively as possible, is also creating a consistent operating model and best practices across the fleet.

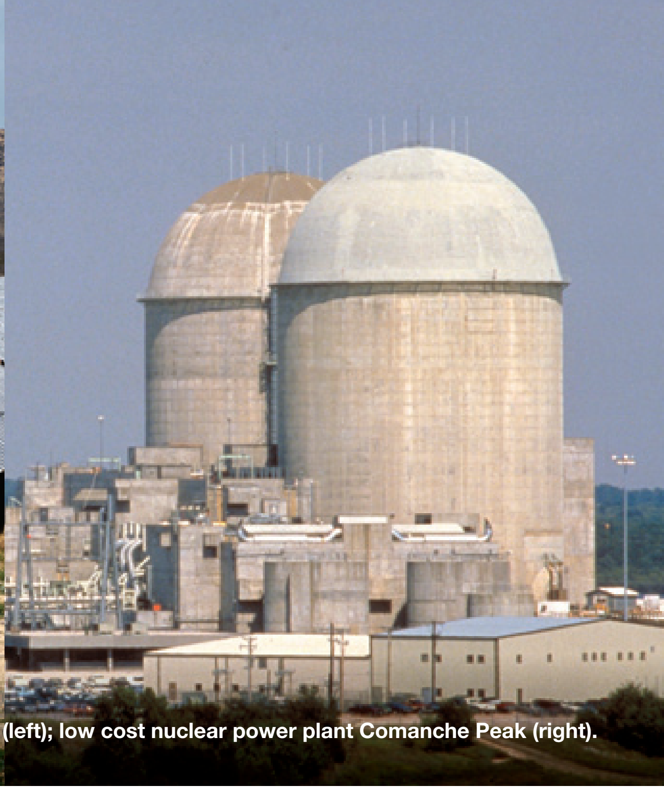
An essential component of Vistra's business is giving back to the communities where we live and work. Our employees volunteered over 5,000 hours through our employee-led volunteer program, Energy in Action.

Finally, we have also meaningfully increased our expectation for incremental after-tax free cash flow synergies, as we now expect to achieve a run rate of $310 million per year compared to our original forecast of $65 million per year that was projected at the time of the merger announcement. These free cash flow synergies primarily reflect interest savings—some of which we have already achieved through balance sheet optimization activities executed in 2018, and the balance of which we expect to realize when we achieve our long-term leverage target of 2.5 times net debt to EBITDA. We were also able to put in place tax strategies that will allow us to utilize approximately $4 billion of Dynegy net operating losses, resulting in approximately $900 million in present value tax savings, or about $2 per share.

After netting the purchase price, we estimate we created nearly $7 billion in value for our stockholders from the Dynegy transaction reflecting only the value created via EBITDA, free cash flow, and tax synergies—allocating no value to the underlying assets. We would not have been able to achieve this level of value creation in such a short period of time on a standalone basis. Moreover, the Dynegy transaction moved us into new markets, shifted us to a gas-predominant generation fleet, exposed us to more stable capacity payments and energy markets in PJM and ISO-NE, and expanded our retail footprint. It was a transformative transaction for our organization and set the stage for a strong 2019.

Strong Operations

Our generation fleet performed exceptionally well in 2018, finishing the year with commercial availability of 94.4 percent compared to a target of 91 percent. Commercial availability is a measure of our fossil fleet's ability to capture gross margin from the market when the assets are in the money, which is a core priority of our operations team and is critical to our success as an organization. Results in the mid-90s are impressive for any generation fleet, and we will continue this focus on strong commercial availability in 2019. Equally important, our generation team saw a decrease in the number of employee injuries with only 44 recordable incidents in 2018, with none being serious or life altering. Vistra as a whole achieved a total recordable injury rate of 0.82, which placed us in the top quartile when compared against industry peers. While we are pleased with the positive trend in improving our safety metrics, we will continue to emphasize the importance of safety in our operations and learn from all events and near misses that occur.

Vistra Energy's Upton 2 solar facility achieved commercial operations on June 1, 2018 (left); low cost nuclear power plant Comanche Peak (right).

On the retail side, we advanced the ball and stayed in front in our retail business with new initiatives such as breakthrough advertising of our popular Free Nights and Solar Days product, the introduction of TXUeLease, an innovative multi-family platform, and implementation of our Formula Won customer experience initiative. We also developed a comprehensive strategy to organically expand our retail business outside of ERCOT. We executed all of these initiatives while organically growing residential customer counts in ERCOT by 15,000, our best year since 2008, expanding our large business markets platform, and integrating the Dynegy retail business. Vistra's retail team continues to excel in the areas of new product and business development, marketing and advertising, brand strategy and management, and customer interaction, as evidenced by the $845 million[1] of adjusted EBITDA delivered by our retail segment in 2018—an increase of nearly 10 percent over our 2017 results.

Growth and Development

In addition to executing on the Dynegy merger, in 2018 we changed the complexion of our company with the addition of renewable and storage assets. Our 180-megawatt Upton 2 solar facility began commercial operations in ERCOT on June 1, 2018. We paired our solar facility with a 10-megawatt/42-megawatt hour Upton 2 battery, which began operating on December 31, 2018. We also announced our Moss Landing battery storage project, a 300-megawatt/1,200-megawatt hour battery project with an associated 20-year resource adequacy contract with Pacific Gas and Electric Company. The project at our Moss Landing site in California is projected to be online in the fourth quarter of 2020 and is currently the world's largest battery project. It will immediately place Vistra in a leadership position in the battery business and could propel us into future opportunities, as batteries and renewable assets continue to be an important component of our country's energy future.

Financial Optimization

The strength of the balance sheet is paramount to our long-term success. Without a strong balance sheet we would not be able to take advantage of growth opportunities like those I just outlined above. In 2018, we started a course that we believe will lead to the possibility of investment grade ratings for our debt—something unheard of in our industry in the recent past. We continue to target the lowest debt in the industry at 2.5 times net debt to EBITDA by year-end 2020, even with the Crius transaction expecting to close in 2019. In 2018, we paid down $1.5 billion and refinanced $10 billion of debt and revolver commitments, resulting in $185 million of interest savings per year.

Community and Sustainability

An essential component of Vistra's business is giving back to the communities where we live and work. Our employees volunteered over 5,000 hours through our employee-led volunteer program, Energy in Action. Vistra employees also pledged more than $1.61 million in our 2018 United Way and TXU Energy Aid℠ campaign. We were honored to receive the Spirit of Caring Award from the United Way of Metropolitan Dallas for our excellence in supporting the United Way's annual campaign and outstanding community involvement throughout the year.

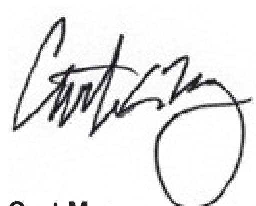
Vistra understands that our operations have an environmental impact, but we also can't lose sight of the fact that electricity is essential to society's most important priorities, and reliable production and delivery of affordable power is a critical service we provide. We are constantly balancing innovation, reliability, and sustainability in our operations. In 2018, we released our first Sustainability Report, which further details our commitments to the environment, our community involvement, and our corporate governance. On our website you can also find a link to our most recent Sustainability Report, which reflects our 2018 sustainability achievements. Later in 2019 we will be announcing our long-term emission targets, so please stay tuned for that announcement.

In Closing

Vistra ended 2018 delivering adjusted EBITDA from ongoing operations of $2.809 billion[1]—impressive results given the relatively mild August in ERCOT, highlighting the strength of our diversified operations and our disciplined focus on cost management. Vistra also delivered adjusted free cash flow before growth from its ongoing operations of $1.611 billion[1], reflecting a free cash flow conversion ratio of nearly 60 percent for the year. This meaningful free cash flow conversion ratio is a highly attractive feature of our company, and is significantly higher than that of other commodity-based, capital-intensive energy industries. In fact, we expect we will generate more than $2 billion in adjusted free cash flow before growth from our ongoing operations in 2019, supporting our diverse capital allocation plan emphasizing disciplined growth, deleveraging, and returning capital to stockholders.

In 2018 Vistra's stock outperformed the S&P 500 by nearly 30 percent as we met the targets we communicated to the financial community and announced a strong outlook for 2019. In fact, as of December 31, 2018, we had outperformed the S&P 500 by more than 80 percent[2] since we emerged from bankruptcy in October 2016. We believe our valuation will continue to improve in 2019 and beyond as the financial markets grow more comfortable with the earnings stability and cash flow generating power of the new integrated power company model, and as we fully rotate our stockholder base. We are referring to 2019 as a "Year of Execution" where we are focused on achieving our financial and leverage targets, returning capital to stockholders, and meeting or exceeding our merger synergy targets. I am confident in our ability to continue to find opportunities that will create value for our stockholders and I look forward to continuing our dialogue.

Sincerely,



Curt Morgan
President and Chief Executive Officer

[1] **Non-GAAP Financial Measures and Forward Looking Statements**
This letter includes references to Adjusted EBITDA and Adjusted Free Cash Flow before Growth, which are non-GAAP financial measures. For reconciliations between our non-GAAP measures and the nearest GAAP measures, please refer to page 6 of this Annual Report. As non-GAAP financial measures are not intended to be considered in isolation or as a substitute for GAAP financial measures, you should carefully read the Form 10-K included in this Annual Report, which includes our consolidated financial statements prepared in accordance with GAAP. Additionally, this letter includes statements that, to the extent they are not recitations of historical fact, constitute forward-looking statements within the meaning of the federal securities laws, and are based on Vistra Energy's current expectations and assumptions. For a discussion identifying important factors that could cause actual results to vary materially from those anticipated in the forward-looking statements, see Vistra Energy's filings with the SEC including, but not limited to, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Risk Factors" in the Form 10-K portion of this Annual Report.

[2] Reflects the increase in Vistra's share price from December 31, 2018 as compared to the price where the Texas Competitive Electric Holdings bonds were trading on September 30, 2016 (immediately prior to emergence from bankruptcy), as adjusted for the special dividend of $2.32/share paid in December 2016.

Non-GAAP Reconciliations — Adjusted EBITDA

Year Ended December 31, 2018 (Unaudited) (Millions of Dollars)

	Retail	Wholesale	Eliminations / Corp and Other	Ongoing Operations Consolidated	Asset Closure	Vistra Energy Consolidated
Net Income (Loss)	$ 712	$ 159	$ (878)	$ (7)	$ (49)	$ (56)
Income tax expense (benefit)	—	—	(45)	(45)	—	(45)
Interest expense and related charges	7	23	542	572	—	572
Depreciation and amortization [(a)]	318	1,068	86	1,472	—	1,472
EBITDA	$ 1,037	$ 1,250	$ (295)	$ 1,992	$ (49)	$ 1,943
Unrealized net (gain) or loss resulting from hedging transactions	(206)	571	15	380	—	380
Fresh start / purchase accounting impacts	26	14	—	40	1	41
Impacts of tax receivable agreement	—	—	79	79	—	79
Non-cash compensation expenses	—	—	73	73	—	73
Transition and merger expenses	1	34	196	231	2	233
Other, net	(13)	32	(23)	(4)	(3)	(7)
Adjusted EBITDA, including Odessa earnout buybacks	$ 845	$ 1,901	$ 45	$ 2,791	$ (49)	$ 2,742
Impact of Odessa earnout buybacks		18		18		18
Adjusted EBITDA	$ 845	$ 1,919	$ 45	$ 2,809	$ (49)	$ 2,760

(a) Includes nuclear fuel amortization of $78 million in ERCOT.

Non-GAAP Reconciliations — Adjusted Free Cash Flow

Year Ended December 31, 2018 (Unaudited) (Millions of Dollars)

	Ongoing Operations	Asset Closure	Vistra Energy Consolidated
Adjusted EBITDA	$ 2,809	$ (49)	$ 2,760
Interest paid, net [(a)]	(636)	—	(636)
Taxes paid [(b)]	(61)	(14)	(75)
Severance	(2)	(20)	(22)
Working capital, margin deposits and derivative related cash activities	(259)	—	(259)
Reclamation and remediation	(41)	(59)	(100)
Taxes related to Alcoa settlement	(45)	—	(45)
Transition and merger expense	(171)	—	(171)
Transition related Capex	(23)	—	(23)
Impact of Odessa earnout buybacks on EBITDA	(18)	—	(18)
Changes in other operating assets and liabilities	64	(4)	(60)
Cash provided by operating activities	$ 1,617	$ (146)	$ 1,471
Capital expenditures including LTSA prepayments and nuclear fuel purchases [(c)]	(510)	—	(510)
Development and growth expenditures	(34)	—	(34)
Other net investing activities [(d)]	(16)	—	(16)
Free cash flow	$ 1,057	$ (146)	$ 911
Working capital, margin deposits and derivative related cash activities	259	—	259
Development and growth expenditures	34	—	34
Severance	2	20	2
Taxes related to Alcoa settlement	45	—	45
Transition and merger expense	171	—	171
Transition related Capex	23	—	23
Other	(2)	—	(2)
Adjusted free cash flow	$ 1,589	$ (126)	$ 1,463
Impact of Odessa earnout buybacks on free cash flow	22	—	22
Adjusted free cash flow before growth	$ 1,611	$ (126)	$ 1,485

(a) Net of interest received. Excludes fees paid on Vistra Operations Credit Facility repricing in February 2018 and refinancing in June 2018, August 2018, and December 2018.
(b) Excludes taxes paid related to Alcoa settlement.
(c) Includes $114 million LTSA financed capital expenditures.
(d) Includes investments in and proceeds from the nuclear decommissioning trust fund and other net investing cash flows.

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018

— OR —

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 001-38086

Vistra Energy Corp.

(Exact name of registrant as specified in its charter)

Delaware	**36-4833255**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6555 Sierra Drive, Irving, Texas 75039	**(214) 812-4600**
(Address of principal executive offices) (Zip Code)	(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $0.01 per share	New York Stock Exchange
Warrants, exercisable for common stock at an exercise price of $35 per 0.652 share	New York Stock Exchange
7.00% tangible equity units	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in rule 405 of the Securities Act. Yes ☐ No ☒

Indicated by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the act. Yes ☐ No ☒

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

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. ☐

As of June 30, 2018, the aggregate market value of the Vistra Energy Corp. common stock held by non-affiliates of the registrant was $8,592,448,694 based on the closing sale price as reported on the New York Stock Exchange.

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of February 25, 2019, there were 485,894,408 shares of common stock, par value $0.01, outstanding of Vistra Energy Corp.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2019 annual meeting of stockholders are incorporated in Part III of this Annual Report on Form 10-K.

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Vistra Energy Corp.'s (Vistra Energy) annual reports, quarterly reports, current reports and any amendments to those reports are made available to the public, free of charge, on the Vistra Energy website at *http://www.vistraenergy.com*, as soon as reasonably practicable after they have been filed with or furnished to the Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. Additionally, Vistra Energy posts important information, including press releases, investor presentations, sustainability reports, and notices of upcoming events on its website and utilizes its website as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of posting to the website by signing up for email alerts and RSS feeds on the "Investor Relations" page of Vistra Energy's website. The information on Vistra Energy's website shall not be deemed a part of, or incorporated by reference into, this annual report on Form 10-K. The representations and warranties contained in any agreement that we have filed as an exhibit to this annual report on Form 10-K, or that we have or may publicly file in the future, may contain representations and warranties that may (i) be made by and to the parties thereto at specific dates, (ii) be subject to exceptions and qualifications contained in separate disclosure schedules, (iii) represent the parties' risk allocation in the particular transaction, or (iv) be qualified by materiality standards that differ from what may be viewed as material for securities law purposes.

This annual report on Form 10-K and other Securities and Exchange Commission filings of Vistra Energy and its subsidiaries occasionally make references to Vistra Energy (or "we," "our," "us" or "the Company"), Luminant, TXU Energy, Value Based Brands LLC, Dynegy Energy Services or Homefield Energy when describing actions, rights or obligations of their respective subsidiaries. These references reflect the fact that the subsidiaries are consolidated with, or otherwise reflected in, their respective parent company's financial statements for financial reporting purposes. However, these references should not be interpreted to imply that the parent company is actually undertaking the action or has the rights or obligations of the relevant subsidiary company or vice versa.

GLOSSARY

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

2017 Form 10-K	Vistra Energy's annual report on Form 10-K for the year ended December 31, 2017, filed with the SEC on February 26, 2018, except for Part II, Items 7 and 8, which were amended in Vistra Energy's current report on Form 8-K filed with the SEC on June 15, 2018
ARO	asset retirement and mining reclamation obligation
CAA	Clean Air Act
CAISO	The California Independent System Operator
CCGT	combined cycle gas turbine
CFTC	U.S. Commodity Futures Trading Commission
Chapter 11 Cases	Cases in the U.S. Bankruptcy Court for the District of Delaware (Bankruptcy Court) concerning voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code (Bankruptcy Code) filed on April 29, 2014 by the Debtors. On the Effective Date, the TCEH Debtors (together with the Contributed EFH Debtors) emerged from the Chapter 11 Cases.
CME	Chicago Mercantile Exchange
CO_2	carbon dioxide
Contributed EFH Debtors	certain EFH Debtors that became subsidiaries of Vistra Energy on the Effective Date
CT	combustion turbine
DIP Facility	TCEH's $3.375 billion debtor-in-possession financing facility, which was repaid in August 2016 (see Note 14 to the Financial Statements)
DIP Roll Facilities	TCEH's $4.250 billion debtor-in-possession and exit financing facilities, which were converted to the Vistra Operations Credit Facilities on the Effective Date (see Note 14 to the Financial Statements)
Debtors	EFH Corp. and the majority of its direct and indirect subsidiaries, including EFIH, EFCH and TCEH but excluding the Oncor Ring-Fenced Entities. Prior to the Effective Date, also included the TCEH Debtors and the Contributed EFH Debtors.
Dynegy	Dynegy Inc., and/or its subsidiaries, depending on context
Dynegy Energy Services	Dynegy Energy Services, LLC and Dynegy Energy Services (East), LLC (d/b/a Dynegy and Brighten Energy), indirect, wholly owned subsidiaries of Vistra Energy, that are REPs in certain areas of MISO and PJM, respectively, and are engaged in the retail sale of electricity to residential and business customers.
EBITDA	earnings (net income) before interest expense, income taxes, depreciation and amortization
EFCH	Energy Future Competitive Holdings Company LLC, a direct, wholly owned subsidiary of EFH Corp. and, prior to the Effective Date, the indirect parent of the TCEH Debtors, depending on context
Effective Date	October 3, 2016, the date the TCEH Debtors and the Contributed EFH Debtors completed their reorganization under the Bankruptcy Code and emerged from the Chapter 11 Cases
EFH Corp.	Energy Future Holdings Corp. and/or its subsidiaries, depending on context, whose major subsidiaries include Oncor and, prior to the Effective Date, included the TCEH Debtors and the Contributed EFH Debtors
EFH Debtors	EFH Corp. and its subsidiaries that are Debtors in the Chapter 11 Cases, including EFIH and EFIH Finance Inc., but excluding the TCEH Debtors and the Contributed EFH Debtors
EFIH	Energy Future Intermediate Holding Company LLC, a direct, wholly owned subsidiary of EFH Corp. and the direct parent of Oncor Holdings
Emergence	emergence of the TCEH Debtors and the Contributed EFH Debtors from the Chapter 11 Cases as subsidiaries of a newly formed company, Vistra Energy, on the Effective Date
EPA	U.S. Environmental Protection Agency
Exchange Act	Exchange Act of 1934, as amended
ERCOT	Electric Reliability Council of Texas, Inc.
Federal and State Income Tax Allocation Agreements	An agreement, executed in May 2012 but effective as of January 2010 to which prior to the Effective Date, EFH Corp. and certain of its subsidiaries (including EFCH, EFIH and TCEH, but not including Oncor Holdings and Oncor) were parties. The Agreement was rejected by the TCEH Debtors and the Contributed EFH Debtors on the Effective Date (see Note 9 to the Financial Statements).

FERC	U.S. Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc. (a credit rating agency)
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GWh	gigawatt-hours
Homefield Energy	Illinois Power Marketing Company (d/b/a Homefield Energy), an indirect, wholly owned subsidiary of Vistra Energy, a REP in certain areas of MISO that is engaged in the retail sale of electricity to municipal customers
ICE	IntercontinentalExchange
IRS	U.S. Internal Revenue Service
ISO	independent system operator
ISO-NE	Independent System Operator New England
kW	kilowatt
LIBOR	London Interbank Offered Rate, an interest rate at which banks can borrow funds, in marketable size, from other banks in the London interbank market
load	demand for electricity
LSTC	liabilities subject to compromise
LTSA	long term service agreements for plant maintenance
Luminant	subsidiaries of Vistra Energy engaged in competitive market activities consisting of electricity generation and wholesale energy sales and purchases as well as commodity risk management
market heat rate	Heat rate is a measure of the efficiency of converting a fuel source to electricity. Market heat rate is the implied relationship between wholesale electricity prices and natural gas prices and is calculated by dividing the wholesale market price of electricity, which is based on the price offer of the marginal supplier (generally natural gas plants), by the market price of natural gas.
Merger	the merger of Dynegy with and into Vistra Energy, with Vistra Energy as the surviving corporation
Merger Agreement	the Agreement and Plan of Merger, dated as of October 29, 2017, by and between Vistra Energy and Dynegy, as it may be amended or modified from time to time
Merger Date	April 9, 2018, the date Vistra Energy and Dynegy completed the transactions contemplated by the Merger Agreement
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	million British thermal units
Moody's	Moody's Investors Service, Inc. (a credit rating agency)
MSHA	U.S. Mine Safety and Health Administration
MW	megawatts
MWh	megawatt-hours
NERC	North American Electric Reliability Corporation
NO_X	nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NYMEX	the New York Mercantile Exchange, a commodity derivatives exchange
NYSE	New York Stock Exchange
NYISO	New York Independent System Operator
Oncor	Oncor Electric Delivery Company LLC, a direct, majority-owned subsidiary of Oncor Holdings and an indirect subsidiary of EFH Corp., that is engaged in regulated electricity transmission and distribution activities
Oncor Holdings	Oncor Electric Delivery Holdings Company LLC, a direct, wholly owned subsidiary of EFIH and the direct majority owner of Oncor, and/or its subsidiaries, depending on context
Oncor Ring-Fenced Entities	Oncor Holdings and its direct and indirect subsidiaries, including Oncor
OPEB	postretirement employee benefits other than pensions

Petition Date	April 29, 2014, the date the Debtors filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code
PJM	PJM Interconnection, LLC
Plan of Reorganization	Third Amended Joint Plan of Reorganization filed by the Debtors in August 2016 and confirmed by the Bankruptcy Court in August 2016 solely with respect to the TCEH Debtors and the Contributed EFH Debtors
PrefCo	Vistra Preferred Inc.
PrefCo Preferred Stock Sale	as part of the Spin-Off, the contribution of certain of the assets of the Predecessor and its subsidiaries by a subsidiary of TEX Energy LLC to PrefCo in exchange for all of PrefCo's authorized preferred stock, consisting of 70,000 shares, par value $0.01 per share
PUCT	Public Utility Commission of Texas
PURA	Texas Public Utility Regulatory Act
REP	retail electric provider
RCT	Railroad Commission of Texas, which among other things, has oversight of lignite mining activity in Texas
RTO	regional transmission organization
S&P	Standard & Poor's Ratings (a credit rating agency)
SEC	U.S. Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
SG&A	selling, general and administrative
Settlement Agreement	Amended and Restated Settlement Agreement among the Debtors, the Sponsor Group, settling TCEH first lien creditors, settling TCEH second lien creditors, settling TCEH unsecured creditors and the official committee of unsecured creditors of TCEH (collectively, the Settling Parties), approved by the Bankruptcy Court in December 2015.
SO_2	sulfur dioxide
Spin-Off	the tax-free spin-off from EFH Corp. executed pursuant to the Plan of Reorganization on the Effective Date by the TCEH Debtors and the Contributed EFH Debtors
Sponsor Group	Refers, collectively, to certain investment funds affiliated with Kohlberg Kravis Roberts & Co. L.P., TPG Global, LLC (together with its affiliates, TPG) and GS Capital Partners, an affiliate of Goldman, Sachs & Co., that have an ownership interest in Texas Energy Future Holdings Limited Partnership, a limited partnership controlled by the Sponsor Group, that owns substantially all of the common stock of EFH Corp.
ST	steam turbine
Tax Matters Agreement	Tax Matters Agreement, dated as of the Effective Date, by and among EFH Corp., EFIH, EFIH Finance Inc. and EFH Merger Co. LLC.
TCJA	The Tax Cuts and Jobs Act of 2017, federal income tax legislation enacted in December 2017, which significantly changed the tax laws applicable to business entities
TRA	Tax Receivables Agreement, containing certain rights (TRA Rights) to receive payments from Vistra Energy related to certain tax benefits, including those it realized as a result of certain transactions entered into at Emergence (see Note 10)
TRE	Texas Reliability Entity, Inc., an independent organization that develops reliability standards for the ERCOT region and monitors and enforces compliance with NERC standards and monitors compliance with ERCOT protocols
TCEH or Predecessor	Texas Competitive Electric Holdings Company LLC, a direct, wholly owned subsidiary of Energy Future Competitive Holdings Company LLC, and, prior to the Effective Date, the parent company of the TCEH Debtors, depending on context, that were engaged in electricity generation and wholesale and retail energy market activities, and whose major subsidiaries included Luminant and TXU Energy
TCEH Debtors	the subsidiaries of TCEH that were Debtors in the Chapter 11 Cases
TCEH Senior Secured Facilities	Refers, collectively, to the TCEH First Lien Term Loan Facilities, TCEH First Lien Revolving Credit Facility and TCEH First Lien Letter of Credit Facility with a total principal amount of $22.616 billion. The claims arising under these facilities were discharged in the Chapter 11 Cases on the Effective Date pursuant to the Plan of Reorganization.
TCEQ	Texas Commission on Environmental Quality

TXU Energy	TXU Energy Retail Company LLC, an indirect, wholly owned subsidiary of Vistra Energy that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
U.S.	United States of America
Value Based Brands	Value Based Brands LLC (d/b/a 4Change Energy and Express Energy), an indirect, wholly owned subsidiary of Vistra Energy that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
Vistra Energy or Successor	Vistra Energy Corp., formerly known as TCEH Corp., and/or its subsidiaries, depending on context. On the Effective Date, the TCEH Debtors and the Contributed EFH Debtors emerged from Chapter 11 and became subsidiaries of Vistra Energy Corp.
Vistra Operations	Vistra Operations Company LLC, an indirect, wholly owned subsidiary of Vistra Energy that is the issuer of certain series of notes (see Note 14 to the Financial Statements) and borrower under the Vistra Operations Credit Facilities
Vistra Operations Credit Facilities	Vistra Operations Company LLC's $8.313 billion senior secured financing facilities (see Note 14 to the Financial Statements)

PART I

Item 1. BUSINESS

References in this report to "we," "our," "us" and "the Company" are to Vistra Energy and/or its subsidiaries, as apparent in the context. See Glossary for defined terms.

Business

Vistra Energy is a holding company operating an integrated retail and generation business in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive electricity market activities including electricity generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity to end users.

We serve approximately 2.8 million customers in five states. Our generation fleet totals approximately 40,500 MW of generation capacity with a portfolio of natural gas, nuclear, coal and solar facilities.

Vistra Energy has six reportable segments: (i) Retail, (ii) ERCOT, (iii) PJM, (iv) NY/NE (comprising NYISO and ISO-NE), (v) MISO and (vi) Asset Closure. The PJM, NY/NE and MISO segments were established on the Merger Date to reflect markets served by businesses acquired in the Merger. See Note 22 to the Financial Statements for further information concerning reportable business segments.

As of December 31, 2018, we had approximately 5,275 full-time employees, including approximately 2,030 employees under collective bargaining agreements.

Merger

On the Merger Date, Vistra Energy and Dynegy completed the transactions contemplated by the Merger Agreement. Pursuant to the Merger Agreement, Dynegy merged with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. See Note 2 to the Financial Statements for a summary of the Merger transaction and business combination accounting.

Business Strategy

Our business strategy is to deliver long-term stakeholder value through a focus on the following areas:

- *Integrated business model.* We believe the key factor that distinguishes us from others in the competitive electricity industry is the integrated nature of our business (*i.e.*, pairing our reliable and efficient mining, diversified generation fleet and wholesale commodity risk management capabilities with our retail platform). Our business strategy will be guided by our integrated business model because we believe it is our core competitive advantage and differentiates us from our non-integrated competitors. We believe our integrated business model creates a unique opportunity because, relative to our non-integrated competitors, it reduces the effects of commodity price movements and contributes to earnings and cash flow stability. Consequently, our integrated business model is at the core of our business strategy.

- *Disciplined capital allocation.* Vistra takes a balanced approach to capital allocation, focusing on maintaining a strong balance sheet, investing prudently in the maintenance of our existing assets and potential growth acquisitions, and returning capital to shareholders. Maintaining a strong balance sheet ensures Vistra's interest expense is manageable in a variety of wholesale power price environments while giving Vistra access to flexible and diverse sources of liquidity. We prudently make necessary capital investments to maintain the safety and reliability of our facilities while also investing in new technologies when economic, including solar assets and battery storage systems, resulting in a continued modernization of Vistra's generation fleet. Because we believe cost discipline and strong management of our assets and commodity positions are necessary to deliver long-term value to our stakeholders, we generally make capital allocation decisions that we believe will lead to attractive cash returns on investment, including by returning capital to our shareholders. In June and November 2018, our board of directors (Board) authorized a share repurchase program under which up to $500 million and $1.25 billion, respectively, of our outstanding common stock may be repurchased. Through December 31, 2018, 33,495,016 shares of our common stock had been repurchased under the program in the aggregate for $778 million (including related fees and expenses) at an average price per share of common stock of $23.23. In November 2018, our Board adopted a dividend program pursuant to which we expect to initiate an annual dividend of approximately $0.50 per share, payable quarterly, beginning in the first quarter of 2019.

- *Superior customer service.* Through TXU Energy and Value Based Brands in Texas, Dynegy Energy Services in Massachusetts, Ohio, Illinois and Pennsylvania and Homefield Energy in Illinois, we serve the retail electricity needs of end-use residential, small business, commercial and industrial electricity customers through multiple sales and marketing channels. In addition to benefitting from our integrated business model, we leverage our brands, our commitment to a consistent and reliable product offering, the backstop of the electricity generated by our generation fleet, our wholesale commodity risk management operations and our strong customer service to differentiate our products and services from our competitors. We strive to be at the forefront of innovation with new offerings and customer experiences to reinforce our value proposition. We maintain a focus on solutions that give our customers choice, convenience and control over how and when they use electricity and related services, including TXU Energy's Free Nights and Solar Days residential plans, MyEnergy Dashboard^{SM}, TXU Energy's iThermostat product and mobile solution, the TXU Energy Rewards program, the TXU Energy Green Up^{SM} renewable energy credit program and a diverse set of solar options. Our focus on superior customer service will guide our efforts to acquire new residential and commercial customers, serve and retain existing customers and maintain valuable sales channels for our electricity generation resources. We believe our customer service, products and trusted TXU Energy brand have resulted in maintaining the highest residential customer retention rate of any Texas retail electric provider in its respective core market.

- *Excellence in operations while maintaining an efficient cost structure.* We believe that operating our facilities in a safe, reliable, environmentally compliant, and cost-effective and efficient manner is a foundation for delivering long-term stakeholder value. We also believe value increases as a function of making disciplined investments that enable our generation facilities to operate not only effectively and efficiently, but also safely, reliably and in an environmentally compliant manner. We believe that an ongoing focus on operational excellence and safety is a key component to success in a highly competitive environment and is part of the unique value proposition of our integrated model. Additionally, we are committed to optimizing our cost structure, reducing our debt levels and implementing enterprise-wide process and operating improvements without compromising the safety of our communities, customers and employees. We believe we have a highly effective and efficient cost structure and that our cost structure supports excellence in our operations.

- *Integrated hedging and commercial management.* Our commercial team is focused on managing risk, through opportunistic hedging, and optimizing our assets and business positions. We actively manage our exposure to wholesale electricity prices in markets in which we operate, on an integrated basis, through contracts for physical delivery of electricity, exchange-traded and over-the-counter financial contracts, term, day-ahead and real-time market transactions, and bilateral contracts with other wholesale market participants, including other power generators and end-user electricity customers. These hedging activities include short-term agreements, long-term electricity sales contracts and forward sales of natural gas through financial instruments. The historically positive correlation between natural gas prices and wholesale electricity prices has provided us an opportunity to manage our exposure to the variability of wholesale electricity prices through natural gas hedging activities. We seek to hedge near-term cash flow and optimize long term value through hedging and forward sales contracts. We believe our integrated hedging and commercial management strategy, in combination with a strong balance sheet and strong liquidity profile, will provide a long-term advantage through cycles of higher and lower commodity prices.

- *Growth and enhancement.* Our growth strategy leverages our core capabilities of multi-channel retail marketing in a large and competitive market, operating large-scale, environmentally sensitive, and diverse assets across a variety of fuel technologies, fuel logistics and management, commodity risk management, cost control, and energy infrastructure investing. We intend to opportunistically evaluate acquisitions of high-quality energy infrastructure assets and businesses that complement these core capabilities and enable us to achieve operational or financial synergies. We are also focused on enhancing our retail platform in markets outside of Texas, including our recently announced entry into a purchase agreement to acquire Crius Energy Trust discussed below. While we are intent on growing our business and creating value for our stockholders, we are committed to making disciplined investments that are consistent with our focus on maintaining a strong balance sheet and strong liquidity profile. As a result, consistent with our disciplined capital allocation approval process, growth opportunities we pursue will need to have compelling economic value in addition to fitting with our business strategy.

- *Corporate responsibility and citizenship.* We are committed to providing safe, reliable, cost-effective and environmentally compliant electricity for the communities and customers we serve. We strive to improve the quality of life in the communities in which we operate. We are also committed to being a good corporate citizen in the communities in which we conduct operations. We and our employees are actively engaged in programs intended to support and strengthen the communities in which we conduct operations. Our foremost giving initiatives are through the United Way and TXU Energy Aid campaigns. TXU Energy Aid has served as an integral resource for social service agencies that assist families in need across Texas pay their electricity bills.

Recent Developments

Entry into Purchase Agreement to Acquire Crius Energy Trust — On February 7, 2019, Vistra Energy and Crius Energy Trust (Crius) entered into a definitive agreement, which was subsequently amended on February 19, 2019 (as amended, the Crius Purchase Agreement), as a result of an unsolicited acquisition proposal, pursuant to which Vistra Energy will acquire the equity interest of two wholly owned subsidiaries of Crius that indirectly own the operating business of Crius (Crius Transaction). Crius is an energy retailer selling both electricity and natural gas products to residential and small business customers in 19 states and the District of Columbia.

The acquisition provides a high degree of overlap with Vistra Energy's generation fleet and contains approximately 11.6 TWh of annual load, improving Vistra Energy's match of its generation to load profile to approximately 45 percent, reducing risk. The acquisition also establishes a platform for future growth by leveraging Vistra Energy's existing retail marketing capabilities and Crius's experienced team. The acquisition enhances the integrated value proposition through collateral and transaction efficiencies, particularly via Crius's largely retail portfolio.

Vistra Energy intends to fund the purchase price of approximately $378 million using cash on hand and assumption of Crius's net debt of approximately $108 million. Completion of the Crius Transaction is subject to various customary conditions, including, among others, (i) approval by at least two-thirds of the Crius unitholders and (ii) receipt of all requisite regulatory approvals, which include approvals of the FERC and the expiration and termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Pending the receipt of all necessary approvals and the fulfillment of all other customary closing conditions, the parties expect the transaction to close in the second quarter of 2019.

Dividend Declaration — On February 26, 2019, Vistra Energy announced that the Board had declared a dividend pursuant to which Vistra Energy would pay, to each holder of record as of March 15, 2019, a dividend of $0.125 per share, to be paid March 29, 2019.

Issuance of Vistra Operations 5.625% Senior Notes Due 2027 — In February 2019, Vistra Operations issued and sold $1.3 billion aggregate principal amount of 5.625% senior notes due 2027 in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act of 1933, as amended. The senior notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and J.P. Morgan Securities, LLC, as representative of the several initial purchasers. Net proceeds from the sale of the senior notes totaling approximately $1.287 billion, together with cash on hand, were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with (i) the 2019 Tender Offer described below, (ii) the redemption of approximately $35 million aggregate principal amount of our 7.375% senior notes due 2022 and (iii) the redemption of the remaining approximately $25 million aggregate principal amount of our outstanding 8.034% senior notes due 2024.

2019 Tender Offer and Consent Solicitation — In February 2019, Vistra Energy used the net proceeds from the issuance of the Vistra Operations 5.625% senior notes due 2027 to fund a cash tender offer (the 2019 Tender Offer) to purchase for cash approximately $1.193 billion aggregate principal amount of 7.375% senior notes due 2022 assumed in the Merger.

Market Discussion

The operations of Vistra Energy are aligned into six reportable business segments: (i) Retail, (ii) ERCOT, (iii) PJM, (iv) NY/NE, (v) MISO and (vi) Asset Closure. The Retail segment is engaged in retail sales of electricity and related services to residential, commercial and industrial customers. The ERCOT, PJM, NY/NE (comprising NYISO and ISO-NE) and MISO segments are engaged in electricity generation, wholesale energy sales and purchases, commodity risk management activities, fuel production and fuel logistics management, all largely within their respective RTO or ISO market. The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines. Our CAISO operations are included in the Corporate and Other non-segment as our operations in the CAISO market do not materially affect our financial condition, results of operations and cash flows. See Note 22 to the Financial Statements for additional information related to our operating segments.

Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in most of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. RTOs and ISOs administer energy and ancillary service markets in the short term, usually day-ahead and real-time markets. Several RTOs and ISOs also ensure long-term planning reserves through monthly, semiannual, annual and multiyear capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets in which we operate currently impose, and will likely continue to impose, bid and price limits or other similar mechanisms. NERC regions and RTOs/ISOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and RTOs/ISOs, their respective roles and responsibilities do not generally overlap.

In RTO and ISO regions with centrally dispatched market structures, all generators selling into the centralized market receive the same price for energy sold based on the bid price associated with the production of the last MWh that is needed to balance supply with demand within a designated zone or at a given location. Different zones or locations within the same RTO/ISO may produce different prices respective to other zones within the same RTO/ISO due to transmission losses and congestion. For example, a less efficient and/or less economical natural gas-fueled unit may be needed in some hours to meet demand. If this unit's production is required to meet demand on the margin, its offer price will set the market clearing price that will be paid for all dispatched generation in the same zone or location (although the price paid at other zones or locations may vary because of transmission losses and congestion), regardless of the price that any other unit may have offered into the market. In RTO and ISO regions with centrally dispatched market structures and location-based marginal price clearing structures (e.g. PJM, ISO-NE, NYISO, ERCOT, MISO, and CAISO), generators will receive the location-based marginal price for their output. The location-based marginal price, absent congestion, would be the marginal price of the most expensive unit needed to meet demand. In regions that are outside the footprint of RTOs/ISOs, prices are determined on a bilateral basis between buyers and sellers.

Retail Markets

The Retail segment is engaged in retail sales of electricity and related services to approximately 2.8 million customers. Substantially all of these activities are conducted by TXU Energy and Value Based Brands in Texas, Dynegy Energy Services in Massachusetts, Ohio, Illinois and Pennsylvania and Homefield Energy in Illinois.

The largest portion of our retail operations are in Texas, where we provide retail electricity to approximately 1.7 million customers in ERCOT. We are an active participant in the competitive ERCOT retail market and continue to be a market leader, which we believe is driven by, among other things, having one of the lowest customer complaint rates according to the PUCT and having an integrated power generation and wholesale operation that allows us to efficiently obtain the electricity needed to serve our customers at the lowest cost. As of December 31, 2018, we provided electricity to approximately 23% and 20% of the residential and commercial customers in ERCOT, respectively. We believe that we have differentiated ourselves by providing a distinctive customer experience predicated on delivering reliable and innovative power products and solutions to our customers, such as Free Nights and Solar Days residential plans, MyEnergy Dashboard℠, TXU iThermostat product and mobile solution, the TXU Energy Rewards program, the TXU Energy Green UP℠ renewable energy credit program and a diverse set of solar options, which give our customers choice, convenience and control over how and when they use electricity and related services. We competitively market electricity and related services to acquire, serve and retain retail customers. We believe we are situated to better serve our retail customers through our unique affiliation with our wholesale commodity risk management personnel who can structure products and contracts in a way that offers significant value compared to stand-alone retail electric providers. Additionally, our wholesale commodity risk management operations protect our retail business from power price volatility by allowing us to bypass bid-ask spread in the market (particularly for illiquid products and time periods), which results in significantly lower collateral costs for our retail business as compared to other, non-integrated retail electric providers. Moreover, our retail business reduces, to some extent, the exposure of our wholesale generation business to wholesale power price volatility. This is because the retail load requirements of our retail operations (primarily TXU Energy) provide a natural offset to the length of Luminant's generation portfolio thereby reducing the exposure to wholesale power price volatility as compared to a non-integrated independent power producer.

We also serve residential, municipal, commercial and industrial customers through our Homefield Energy and Dynegy Energy Services retail businesses, through which we provide retail electricity to approximately 1.1 million customers in Illinois, Massachusetts, Ohio and Pennsylvania.

ERCOT Market

ERCOT is an ISO that manages the flow of electricity from approximately 78,000 MW of installed capacity to approximately 25 million Texas customers, representing approximately 90% of the state's electric load.

As an energy-only market, ERCOT's market design is distinct from other competitive electricity markets in the U.S. Other markets maintain a minimum planning reserve margin through regulated planning, resource adequacy requirements and/or capacity markets. In contrast, ERCOT's resource adequacy is predominately dependent on energy-market price signals. ERCOT implemented the Operating Reserve Demand Curve (ORDC), pursuant to which wholesale electricity prices in the real-time electricity market increase automatically as available operating reserves decrease below defined threshold levels, creating a price adder. When operating reserves drop to 2,000 MW or less, the ORDC automatically adjusts power prices to the established value of lost load (VOLL), which is set at $9,000/MWh. Because ERCOT has limited excess generation capacity to meet high demand days due to its minimal import capacity, and peaking facilities have high operating costs, the marginal price of supply rapidly increases during periods of high demand. Historically, elevated temperatures in the summer months have driven high electricity demand in ERCOT. Many generators benefit from these sporadic periods of "scarcity pricing" in which power prices may increase significantly, up to the current $9,000/MWh price cap.

Transactions in ERCOT take place in two key markets: the day-ahead market and the real-time market. The day-ahead market is a voluntary, forward electricity market conducted the day before each operating day in which generators and purchasers of electricity may bid for one or more hours of electricity supply or consumption. The real-time market is a spot market in which electricity may be sold in five-minute intervals. The day-ahead market provides market participants with visibility into where prices are expected to clear, and the prices are not impacted by subsequent events. Conversely, the real-time market exposes purchasers to the risk of transient operational events and price spikes. These two markets allow market participants to manage their risk profile by adjusting their participation in each market. In addition, ERCOT uses ancillary services to maintain system reliability, including regulation service-up, regulation service-down, responsive reserve service and non-spinning reserve service. Regulation service up and down are used to balance the grid in a near-instantaneous fashion when supply and demand fluctuate due to a variety of factors, such as weather, generation outages, renewable production intermittency and transmission outages. Responsive reserves and non-spinning reserves are used by ERCOT when the grid is at, near or recovering from a state of emergency due to inadequate generation. Because ERCOT has one of the highest concentrations of wind capacity generation among U.S. markets, the ERCOT market is more susceptible to fluctuations in wholesale electricity supply due to intermittent wind production, making ERCOT more vulnerable to periods of generation scarcity.

Our ERCOT segment is comprised of 20 power generation facilities located in Texas totaling 18,366 MW of generation capacity. Our ERCOT fleet includes seven CCGT natural gas-fueled generation facilities totaling 7,838 MW, three lignite/coal-fueled generation facilities totaling 4,500 MW, eight natural gas-fueled peaking generation facilities totaling 3,538 MW, a nuclear generation facility totaling 2,300 MW, a solar photovoltaic power generation facility totaling 180 MW and a battery energy storage system totaling 10 MW.

PJM Market

PJM is an RTO that manages the flow of electricity from approximately 178,000 MW of generation capacity to approximately 65 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing a locational marginal pricing (LMP) methodology which calculates a price for every generator and load point within PJM. This market is transparent, allowing generators and load serving entities to see real-time price effects, transmission constraints and the impacts of congestion at each pricing point. PJM operates day-ahead and real-time markets into which generators can bid to provide energy and ancillary services. PJM also administers a forward capacity auction, the Reliability Pricing Model (RPM), which establishes long-term markets for capacity. We have participated in RPM base residual auctions for years up to and including PJM's planning year 2021-2022, which ends May 31, 2022. We also enter into bilateral capacity transactions. PJM's Capacity Performance (CP) rules are designed to improve system reliability and include penalties for under-performing units and reward for over-performing units during shortage events. PJM's base capacity resources are those capacity resources not capable of sustained, predictable operation throughout the entire delivery year, but can provide energy and reserves during hot weather operations. The base capacity resources are subject to non-performance charges assessed during emergency conditions from June through September. Full transition of the capacity market to CP rules will occur by planning year 2020-2021. An independent market monitor continually monitors PJM markets to ensure a robust, competitive market and to identify an improper behavior by any entity.

Our PJM segment is comprised of 17 power generation facilities totaling 10,769 MW of generating capacity. Our PJM fleet includes eight CCGT natural gas-fueled generation facilities totaling 5,902 MW, three coal-fueled generation facilities totaling 3,428 MW and six natural gas- or oil-fueled generation facilities totaling 1,439 MW. Of these facilities, eight are located in Ohio, three in Pennsylvania, three in Illinois and one each in New Jersey, Virginia and West Virginia.

NYISO and ISO-NE Markets

NYISO is an ISO that manages the flow of electricity from approximately 39,000 MW of generation capacity to approximately 20 million New York customers.

The NYISO market dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Energy prices vary among the regional zones in the NYISO and are largely influenced by transmission constraints and fuel supply. NYISO offers a forward capacity market where capacity prices are determined through auctions. Strip auctions occur one to two months prior to the commencement of a six-month seasonal planning period. Subsequent auctions provide an opportunity to sell excess capacity for the balance of the seasonal planning period or the upcoming month. Due to the short-term nature of the NYISO-operated capacity auctions and a relatively liquid bilateral market for NYISO capacity products, our Independence facility sells a significant portion of its capacity through bilateral transactions. The balance is cleared through the seasonal and monthly capacity auctions.

ISO-NE is an ISO that manages the flow of electricity from approximately 31,000 MW of installed generation capacity to approximately 15 million customers in the states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine.

ISO-NE dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Energy prices vary among the participating states in ISO-NE and are largely influenced by transmission constraints and fuel supply. ISO-NE offers a forward capacity market where capacity prices are determined through auctions. Performance incentive rules went into effect for planning year 2018-2019 (FCA-9), which will have the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level.

Our NY/NE segment is comprised of eight CCGT natural gas-fueled generation facilities totaling 4,730 MW of generation capacity. Of these facilities, four are located in Massachusetts, two in Connecticut and one each in Maine and New York.

MISO Market

MISO is an RTO that manages the flow of electricity from approximately 200,000 MW of installed capacity to approximately 42 million customers in all or parts of Iowa, Minnesota, North Dakota, Wisconsin, Michigan, Kentucky, Indiana, Illinois, Missouri, Arkansas, Mississippi, Texas, Louisiana, Montana, South Dakota and Manitoba, Canada.

The MISO energy market is designed to ensure that all market participants have open-access to the transmission system on a non-discriminatory basis. MISO, as an independent RTO, maintains functional control over the use of the transmission system to ensure transmission circuits do not exceed their secure operating limits and become overloaded. MISO operates day-ahead and real-time energy markets using a similar LMP methodology as described above for the PJM market. An independent market monitor is responsible for evaluating the performance of the markets and identifying conduct by market participants or MISO that may compromise the efficiency or distort the outcome of the markets.

MISO administers a one-year FCA for the next planning year from June 1st of the current year to May 31st of the following year. We participate in these auctions with open capacity that has not been committed through bilateral or retail transactions. We also participate in the MISO annual and monthly FTR auctions to manage the cost of our transmission congestion, as measured by the congestion component of the LMP price differential between two points on the transmission grid across the market area.

Our MISO segment is comprised of eight power generation facilities located in Illinois totaling 5,476 MW of generation capacity. Joppa, which is within the Electric Energy, Inc. (EEI) control area, is interconnected to Tennessee Valley Authority and Louisville Gas and Electric Company, but primarily sells its capacity and energy to MISO. We currently offer a portion of our MISO segment generating capacity and energy into PJM. Our Coffeen, Duck Creek, Edwards and Newton generation facilities have 2,540 MW electrically tied into PJM through pseudo-tie arrangements. Our Hennepin generation facility offers 294 MW of the facility's energy and capacity into PJM as a block schedule and began dispatching as a pseudo-tie unit for planning year 2018-2019.

CAISO Market

CAISO is an ISO that manages the flow of electricity from approximately 60,000 MW of installed capacity to approximately 30 million customers primarily in California, representing approximately 80% percent of the state's electric load.

Energy is priced utilizing an LMP methodology as described above. The capacity market is comprised of Generic, Flexible and Local Resource Adequacy (RA) Capacity and is administered by the California Public Utilities Commission. Unlike other centrally cleared capacity markets, the resource adequacy market in California is a bilaterally traded market. In November 2016, CAISO implemented a voluntary capacity auction for annual, monthly, and intra-month procurement to cover for deficiencies in the market. The voluntary Competitive Solicitation Process, which FERC approved in October 2015, is a modification to the Capacity Procurement Mechanism (CPM) and provides another avenue to sell RA capacity. There have been recent CPM designations through the Competitive Solicitation Process. These include Moss Landing Unit 1 for 510 MW for the calendar year 2018 and Moss Landing Unit 2 intra-monthly designation for 29 MW for September through November 2018.

Our CAISO operations are comprised of two power generation facilities located in California totaling 1,185 MW of generating capacity. Our CAISO fleet includes one CCGT natural gas-fueled generation facility totaling 1,020 MW and one oil-fueled generation facility totaling 165 MW. In June 2018, we announced that we will enter into a 20-year resource adequacy contract with Pacific Gas and Electric Company (PG&E) to develop a 300 MW battery energy storage project at our Moss Landing Power Plant site in California. PG&E filed its application with the California Public Utilities Commission (CPUC) in June 2018 and the CPUC approved the contract in November 2018. We anticipate the battery storage project will enter commercial operations by the fourth quarter of 2020.

Wholesale Operations

Our wholesale commodity risk management group is responsible for dispatching our generation fleet in response to market needs after implementing portfolio optimization strategies, thus linking and integrating the generation fleet production with our retail customer and wholesale sales opportunities. Market demand, also known as load, faced by electric power systems, such as those we operate in, varies from moment to moment as a result of changes in business and residential demand, which is often driven by weather. Unlike most other commodities, the production and consumption of electricity must remain balanced on an instantaneous basis. There is a certain baseline demand for electricity across an electric power system that occurs throughout the day, which is typically satisfied by baseload generating units with low variable operating costs. Baseload generating units can also increase output to satisfy certain incremental demand and reduce output when demand is unusually low. Intermediate/load-following generating units, which can more efficiently change their output to satisfy increases in demand, typically satisfy a large proportion of changes in intraday load as they respond to daily increases in demand or unexpected changes in supply created by reduced generation from renewable resources or other generator outages. Peak daily loads may be satisfied by peaking units. Peaking units are typically the most expensive to operate, but they can quickly start up and shut down to meet brief peaks in demand. In general, baseload units, intermediate/load following units and peaking units are dispatched into the RTO/ISO grid in order from lowest to highest variable cost. Price formation is typically based on the highest variable cost unit that clears the market to satisfy system demand at a given point in time.

Our commodity risk management group also enters into electricity, gas and other commodity derivative contracts to reduce exposure to changes in prices primarily to hedge future revenues and fuel costs for our generation facilities and purchased power costs for our Retail segment.

Seasonality

The demand for and market prices of electricity and natural gas are affected by weather. As a result, our operating results may fluctuate on a seasonal basis. Typically, demand for and the price of electricity is higher in the summer and winter seasons, when the temperatures are more extreme, and the demand for and price of natural gas is also generally higher in the winter. More severe weather conditions such as heat waves or extreme winter weather may make such fluctuations more pronounced. However, not all regions of the U.S. typically experience extreme weather conditions at the same time, so Vistra Energy is typically not exposed to the effects of extreme weather in all parts of its business at once. The pattern of this fluctuation may change depending on, among other things, the retail load served and the terms of contracts to purchase or sell electricity.

Competition

Competition in the markets in which we operate is impacted by electricity and fuel prices, congestion along the power grid, subsidies provided by state and federal governments for new and existing generation facilities, new market entrants, construction of new generating assets, technological advances in power generation, the actions of environmental and other regulatory authorities, and other factors. We primarily compete with other electricity generators and retailers based on our ability to generate electric supply, market and sell electricity at competitive prices and to efficiently utilize transportation from third-party pipelines and transmission from electric utilities to deliver electricity to end-users. Competitors in the generation and retail power markets in which we participate include regulated utilities, industrial companies, non-utility generators, competitive subsidiaries of regulated utilities, independent power producers, REPs and other energy marketers. See Item 1A. *Risk Factors* for additional information concerning the risks faced with respect to the competitive energy markets in which we operate.

Brand Value

Our TXU Energy brand, which has been used to sell electricity to customers in the competitive retail electricity market in Texas for approximately 17 years, is registered and protected by trademark law and is the only material intellectual property asset that we own. As of December 31, 2018, we have reflected an intangible asset on our balance sheet for the TXU Energy brand of approximately $1.2 billion (see Note 8 to the Financial Statements).

Environmental Regulations and Related Considerations

We are subject to extensive environmental regulation by governmental authorities, including the EPA and the environmental regulatory bodies of states in which we operate. The EPA has recently finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. See Item 1A. *Risk Factors* for additional discussion of risks posed to us regarding regulatory requirements. See Note 15 to the Financial Statements for a discussion of litigation related to EPA reviews.

Climate Change

There is a debate nationally and internationally about global climate change and how greenhouse gas (GHG) emissions, such as carbon dioxide (CO_2), might contribute to global climate change. GHG emissions from the combustion of fossil fuels, primarily by our coal/lignite-fueled-generation plants, represent the substantial majority of our total GHG emissions. CO_2, methane and nitrous oxide are emitted in this combustion process, with CO_2 representing the largest portion of these GHG emissions. We estimate that our generation facilities produced approximately 135 million short tons of CO_2 in 2018.

Greenhouse Gas Emissions

In August 2015, the EPA finalized rules to address GHG emissions from new, modified and reconstructed and existing electricity generation units, referred to as the Clean Power Plan, including rules for existing facilities that would establish state-specific emissions rate goals to reduce nationwide CO_2 emissions. Various parties (including Luminant) filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court), and subsequently, in January 2016, a coalition of states, industry (including Luminant) and other parties filed applications with the U.S. Supreme Court (Supreme Court) asking that the Supreme Court stay the rule while the D.C. Circuit Court reviews the legality of the rule for existing plants. In February 2016, the Supreme Court stayed the rule pending the conclusion of legal challenges on the rule before the D.C. Circuit Court and until the Supreme Court disposes of any subsequent petition for review. Oral argument on the merits of the legal challenges to the rule was heard in September 2016 before the entire D.C. Circuit Court, but the D.C. Circuit Court has not issued a decision and the case remains in abeyance due to the EPA's decision to review the Clean Power Plan.

In October 2017, the EPA issued a proposed rule that would repeal the Clean Power Plan with the proposed repeal focusing on what the EPA believes to be the unlawful nature of the Clean Power Plan and asking for public comment on the EPA's interpretations of its authority under the Clean Air Act. In December 2017, the EPA published an advance notice of proposed rulemaking (ANPR) soliciting information from the public as the EPA considers proposing a future rule. Vistra Energy submitted comments on the ANPR in February 2018. Vistra Energy submitted comments on the proposed repeal in April 2018. In August 2018, the EPA published a proposed replacement rule called the Affordable Clean Energy rule. We submitted comments on the proposed Affordable Clean Energy rule in October 2018. In December 2018, the EPA issued proposed revisions to the emission standards for new, modified and reconstructed units with comments due in March 2019. While we cannot predict the outcome of these rulemakings and related legal proceedings, or estimate a range of reasonably probable costs, if the rules are ultimately implemented or upheld as they were issued, they could have a material impact on our results of operations, liquidity or financial condition.

State Regulation of GHGs

Many states where we operate generation facilities have, are considering, or are in some stage of implementing, state-only regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change.

Regional Greenhouse Gas Initiative (RGGI) — RGGI is a state-driven GHG emission control program that took effect in 2009 and was initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented a cap-and-trade program. Compliance with RGGI can be achieved by reducing emissions, purchasing or trading allowances or securing offset allowances from an approved offset project. We are required to hold allowances equal to at least 50 percent of emissions in each of the first two years of the three-year control period.

In December 2017, the RGGI states released an updated model rule with changes to the CO_2 budget trading program, including an additional 30 percent reduction in the CO_2 annual cap by the year 2030, relative to 2020 levels. The RGGI cap on CO_2 emissions would decline by 2.275 million tons per year beginning in 2021. Each RGGI state will work to ensure that its program changes are in effect by 2021.

Our generating facilities in Connecticut, Maine, Massachusetts and New York emitted approximately 8.3 million tons of CO_2 during 2018. The spot market price of RGGI allowances required to operate these facilities as of December 31, 2018 was approximately $5.39 per allowance. The spot market price of RGGI allowances required to operate our affected facilities during 2019 was $5.40 per allowance on February 25, 2019. While the cost of allowances required to operate our RGGI-affected facilities is expected to increase in future years, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue.

Massachusetts — In August 2017, the Massachusetts Department of Environmental Protection (MassDEP) adopted final rules establishing an annual declining limit on aggregate CO_2 emissions from 21 in-state fossil-fueled electricity generation units. The rules establish an allowance trading system under which the annual aggregate electricity generation unit sector cap on CO_2 emissions declines from 8.96 million metric tons in 2018 to 1.8 million metric tons in 2050. MassDEP allocated emission allowances to affected facilities for 2018. Beginning in 2019, the allocation process will transition to a competitive auction process. Allowances for 2019 and 2020 will be partially distributed through a competitive auction process and partially distributed based on the process and schedule established by the rule. Beginning in 2021, all allowances will be distributed through the auction. Limited banking of unused allowances is allowed. The New England Power Generators Association, in which we are a member, and other generators filed complaints in Massachusetts superior court challenging the rules. In January 2018, the Massachusetts Supreme Judicial Court decided to review the challenges to MassDEP's electricity generation unit's CO_2 rules and transferred the case from the superior court where the rule was upheld. Based on current projections of operations for our Massachusetts generating facilities in 2019, we anticipate that allocated allowances will cover CO_2 emissions. We expect the rules will have little or no near-term impact on the financial results of our generating facilities in Massachusetts. However, if upheld, the rules would have an adverse impact on the long-term future of these facilities.

Virginia — In January 2018, the Virginia Department of Environmental Quality issued a proposed rule to adopt a carbon cap-and trade program for fossil-fueled electricity generation units, including our Hopewell facility, beginning in 2020. The proposed program is based on the RGGI proposed 2017 model rule and is intended to link Virginia to RGGI.

New Jersey — In January 2018, the Governor of New Jersey signed an executive order directing the state's environmental agency and public utilities board to begin the process of rejoining RGGI. In December 2018, New Jersey published two rule proposals that would establish the mechanisms for New Jersey to rejoin RGGI.

California — Our assets in California are subject to the California Global Warming Solutions Act, which required the California Air Resources Board (CARB) to develop a GHG emission control program to reduce emissions of GHGs in the state to 1990 levels by 2020. In April 2015, the Governor of California issued an executive order establishing a new statewide GHG reduction target of 40 percent below 1990 levels by 2030 to ensure California meets its 2050 GHG reduction target of 80 percent below 1990 levels. The CARB and the Province of Québec held their seventeenth joint allowance auction in November 2018 with current vintage auction allowances selling at a clearing price of $15.31 per metric ton and 2021 auction allowances selling at a clearing price of $15.33 per metric ton. The CARB expects allowance prices to be in the $15 to $30 range by 2020. We have participated in quarterly auctions or in secondary markets, as appropriate, to secure allowances for our affected assets.

In July 2017, California enacted legislation extending its GHG cap-and-trade program through 2030 and the CARB adopted amendments to its cap-and-trade regulations that, among other things, established a framework for extending the program beyond 2020 and linking the program to the new cap-and-trade program in Ontario, Canada beginning in January 2018.

Air Emissions

The Clean Air Act (CAA)

The CAA and comparable state laws and regulations relating to air emissions impose various responsibilities on owners and operators of sources of air emissions, which include requirements to obtain construction and operating permits, pay permit fees, monitor emissions, submit reports and compliance certifications, and keep records. The CAA requires that fossil-fueled electricity generation plants meet certain pollutant emission standards and have sufficient emission allowances to cover sulfur dioxide (SO_2) emissions and in some regions nitrogen oxide (NO_X) emissions.

In order to ensure continued compliance with the CAA and related rules and regulations, we utilize various emission reduction technologies. These technologies include flue gas desulfurization (FGD) systems, dry sorbent injection (DSI), baghouses and activated carbon injection or mercury oxidation systems on select units and electrostatic precipitators, selective catalytic reduction (SCR) systems, low-NO_X burners and/or overfire air systems on all units. Additionally, our MISO coal-fueled facilities mainly use low sulfur coal, which, prior to combustion, goes through a refined coal process to further reduce NO_X and mercury emissions. In 2018, we received approval to use refined coal at some of our Texas coal-fueled facilities.

Cross-State Air Pollution Rule (CSAPR)

In July 2011, the EPA issued the CSAPR, compliance with which would have required significant additional reductions of SO_2 and NO_X emissions from our fossil-fueled generation units. After certain EPA revisions to the rule the CSAPR became effective January 1, 2015. In October 2016, the EPA issued a CSAPR update, which revised the ozone season NOx limits for 22 eastern states, including Texas. Under the CSAPR, our generating facilities in Illinois, Ohio, New Jersey, New York, Pennsylvania, Virginia, and West Virginia are subject to cap-and-trade programs for ozone-season emissions of NOx from May 1 through September 30 and for annual emissions for SO_2 and NO_X. Our generating facilities in Texas are subject to the CSAPR NOx ozone season cap-and-trade program. While we cannot predict the outcome of future proceedings related to the CSAPR, based upon our current operating plans, we do not believe that the CSAPR itself will cause any material operational, financial or compliance issues to our business or require us to incur any material compliance costs.

Regional Haze — Reasonable Progress and Best Available Retrofit Technology (BART) for Texas

The Regional Haze Program of the CAA establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I federal areas which impairment results from man-made pollution." There are two components to the Regional Haze Program. First, states must establish goals for reasonable progress for Class I federal areas within the state and establish long-term strategies to reach those goals and to assist Class I federal areas in neighboring states to achieve reasonable progress set by those states towards a goal of natural visibility by 2064. Second, certain electricity generation units built between 1962 and 1977 are subject to BART standards designed to improve visibility if such units cause or contribute to impairment of visibility in a federal class I area. BART reductions of SO_2 and NO_X are required either on a unit-by-unit basis or are deemed satisfied by state participation in an EPA-approved regional trading program such as the CSAPR or other approved alternative program.

In January 2016, the EPA issued a final rule approving in part and disapproving in part Texas's 2009 State Implementation Plan (SIP) as it relates to the reasonable progress component of the Regional Haze Program and issuing a Federal Implementation Plan (FIP). The EPA's emission limits in the FIP assume additional control equipment for specific lignite/coal-fueled generation units across Texas, including new flue gas desulfurization systems (scrubbers) at seven electricity generation units (including Big Brown Units 1 and 2, Monticello Units 1 and 2 and Coleto Creek) and upgrades to existing scrubbers at seven generation units (including Martin Lake Units 1, 2 and 3, Monticello Unit 3 and Sandow Unit 4).

In March 2016, Luminant and a number of other parties, including the State of Texas, filed petitions for review in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court) challenging the FIP's Texas requirements. In July 2016, the Fifth Circuit Court granted motions to stay the rule filed by Luminant and the other parties pending final review of the petitions for review. In December 2016, the EPA filed a motion seeking a voluntary remand of the rule back to the EPA for further consideration of Luminant's pending request for administrative reconsideration. In March 2017, the Fifth Circuit Court remanded the rule back to the EPA for reconsideration. The stay of the rule (and the emission control requirements) remains in effect, and the EPA is required to file status reports of its reconsideration every 60 days. The retirements of our Monticello, Big Brown and Sandow 4 plants should have a favorable impact on this rulemaking and litigation. While we cannot predict the outcome of the rulemaking and legal proceedings, or estimate a range of reasonably possible costs, the result could have a material impact on our results of operations, liquidity or financial condition.

In September 2017, the EPA signed a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas's 2009 SIP and a partial FIP. For SO_2, the rule creates an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generating units (including our Martin Lake, Big Brown, Monticello, Sandow 4, Coleto Creek, Stryker 2 and Graham 2 plants). The compliance obligations in the program started on January 1, 2019, and the identified units receive an annual allowance allocation that is equal to their most recent annual CSAPR SO_2 allocation. Cumulatively, our units covered by the program are allocated 100,279 allowances annually. Under the rule, a unit that is listed that does not operate for two consecutive years starting after 2018 would no longer receive allowances after the fifth year of non-operation. We believe the retirements of our Monticello, Big Brown and Sandow 4 plants will enhance our ability to comply with this BART rule for SO_2. For NO_X, the rule adopts the CSAPR's ozone program as BART and for particulate matter, the rule approves Texas's SIP that determines that no electricity generation units are subject to BART for particulate matter. The National Parks Conservation Association, the Sierra Club and the Environmental Defense Fund filed a petition challenging the rule in the Fifth Circuit Court as well as a petition for reconsideration filed with the EPA. Luminant intervened on behalf of the EPA in the Fifth Circuit Court action. In March 2018, the Fifth Circuit Court granted a joint motion filed by the EPA and the environmental groups involved to abate the Fifth Circuit Court proceedings until the EPA has taken action on the reconsideration petition and concludes the reconsideration process. In August 2018, the EPA issued a proposed rule affirming the prior BART final rule and seeking comments on that proposal, which were due in October 2018. While we cannot predict the outcome of the rulemaking and legal proceedings, we believe the rule, if ultimately implemented or upheld as issued, will not have a material impact on our results of operations, liquidity or financial condition.

Affirmative Defenses During Malfunctions

In February 2013, the EPA proposed a rule requiring certain states to remove SIP exemptions for excess emissions during malfunctions or replace them with an affirmative defense. In May 2015, the EPA finalized its 2013 proposal to extend the EPA's proposed findings of inadequacy to states that have affirmative defense provisions, including Texas. The final rule impacted 36 states, including Texas, Illinois and Ohio, in which we operate. The EPA's final rule would require covered states to remove or replace either EPA-approved exemptions or affirmative defense provisions for excess emissions during startup, shutdown and maintenance events. Several states (including the State of Texas and the State of Ohio) and various industry parties (including Luminant) filed petitions for review of the EPA's final rule, and all of those petitions were consolidated in the D.C. Circuit Court. Before the oral argument was held, in April 2017, the D.C. Circuit Court granted the EPA's motion to continue oral argument and ordered that the case be held in abeyance with the EPA to provide status reports to the D.C. Circuit Court on the EPA's review of the action at 90-day intervals. In October 2018, the EPA partially granted Texas' petition for reconsideration of the Texas SIP call. We cannot predict the timing or outcome of this proceeding, or estimate a range of reasonably possible costs, but implementation of the rule as finalized could have a material impact on our results of operations, liquidity or financial condition.

National Ambient Air Quality Standards (NAAQS)

The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has established NAAQS for six such pollutants, including SO_2 and ozone. Each state is responsible for developing a SIP that will attain and maintain the NAAQS. These plans may result in the imposition of emission limits on our facilities.

SO_2 Designations for Texas — In November 2016, the EPA finalized its nonattainment designations for counties surrounding our Big Brown, Monticello and Martin Lake generation plants. The final designations require Texas to develop nonattainment plans for these areas. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court. Subsequently, in October 2017, the Fifth Circuit Court granted the EPA's motion to hold the case in abeyance considering the EPA's representation that it intended to revisit the nonattainment rule. In December 2017, the TCEQ submitted a petition for reconsideration to the EPA. In addition, with respect to Monticello and Big Brown, the retirement of those plants should favorably impact our legal challenge to the nonattainment designations in that the nonattainment designations for Freestone County and Titus County are based solely on the Sierra Club modeling, which we dispute, of SO_2 emissions from Monticello and Big Brown. Regardless, considering these retirements, the nonattainment designations for those counties are no longer supported. While we cannot predict the outcome of this matter, or estimate a range of reasonably possible costs, the result could have a material impact on our results of operations, liquidity or financial condition.

Ozone Designations — The EPA issued a final rule in October 2015 lowering the ozone NAAQS from 75 to 70 parts per billion. Various parties have filed lawsuits challenging the 2015 ozone NAAQS. In November 2017, the EPA issued an initial round of area designations for the 2015 ozone NAAQS, designating most areas of the U.S. as attainment/unclassifiable. Several states and other groups have filed lawsuits seeking to compel the EPA to complete designations for all areas of the country. In December 2017, the EPA notified states of expected nonattainment area designations for the 2015 ozone NAAQS. Those areas include areas concerning our Dicks Creek, Miami Fort and Zimmer facilities in Ohio, our Calumet facility in Illinois and our Wise, Ennis and Midlothian facilities in Texas. In June 2018, the EPA finalized these designations as marginal nonattainment areas.

In November 2017, the EPA denied a petition from nine northeastern states to add several states, including Illinois and Ohio, to the Ozone Transport Region. Eight of the northeastern states have filed a petition for judicial review challenging the EPA's action in the D.C. Circuit Court. Briefing in the D.C. Circuit Court was completed in October 2018, and oral argument was held in November 2018. Additionally, in January 2018, New York and Connecticut filed a lawsuit against the EPA in the Southern District of New York seeking to compel the agency to issue a FIP for the 2008 ozone NAAQS that addresses sources in five upwind states, including Illinois. The plaintiffs filed a motion for summary judgment on the matter in April 2018, and the court granted that motion in June 2018. As a result, the EPA was required to propose an action to address the 2008 ozone NAAQS by June 29, 2018, and promulgate a final action by December 6, 2018. In January 2019, the plaintiffs informed the court that the EPA had satisfied its deadlines in accordance with the court's order. However, in January 2019, New York, Connecticut, four other states and the City of New York filed a separate petition for review in the D.C. Circuit Court challenging the final action the EPA took in December 2018 consistent with the Southern District of New York's order.

In November 2016, the State of Maryland petitioned the EPA to impose additional NO_X emission control requirements on 36 electricity generation units in five upwind states, including our Zimmer facility, that the State alleges are contributing to nonattainment with the 2008 ozone NAAQS in Maryland. In the fall of 2017, Maryland and several environmental groups filed lawsuits against the EPA seeking to compel the Agency to act on the State's petition. In October 2018, the EPA took final action denying the Maryland petition. While we cannot predict the outcome of the judicial proceedings, given that the Zimmer facility utilizes SCR technology to control NO_X emissions, we do not believe that the result of these proceedings could cause a material adverse impact on our future financial results.

Illinois Multi-Pollutant Standards (MPS)

In 2007, our MISO coal-fueled generation facilities elected to demonstrate compliance with the Illinois MPS, which require compliance with NO_X, SO_2 and mercury emissions limits. We are in compliance with the MPS. In October 2017, the Illinois Environmental Protection Agency (IEPA) filed a proposed rule with the Illinois Pollution Control Board (IPCB) that would amend the MPS rule by replacing the two separate group-wide annual emission rate limits that currently apply to our eight downstate Illinois coal-fueled stations with tonnage limits for both SO_2 (annual) and NO_X (annual and seasonal) that apply to the eight stations as a single group. Under the MPS proposal, allowable annual emissions of SO_2 and NO_X would be 32 percent lower than under the current rule. All other federal and state air quality regulations, including health-based standards, would remain unchanged and in place. The proposed rule also would impose new requirements to ensure the continuous operation of existing SCR control systems during the ozone season, require SCR-controlled units to meet an ozone season NO_X emission rate limit, and set an additional, site-specific annual SO_2 limit for our Joppa Power Station. We are supportive of the proposed rule as it would provide operational flexibility to our MISO fleet while also providing a number of regulatory and environmental benefits. IPCB held five hearings on the rule and we expect it to be finalized in 2019.

New Source Review and CAA Matters

New Source Review — Since 1999, the EPA has engaged in a nationwide enforcement initiative to determine whether coal-fueled power plants failed to comply with the requirements of the New Source Review (NSR) and New Source Performance Standard provisions under the CAA when the plants implemented changes. The EPA's NSR initiative focuses on whether projects performed at power plants triggered various permitting requirements, including the need to install pollution control equipment.

In August 2013, the U.S. Department of Justice (DOJ), acting as the attorneys for the EPA, filed a civil enforcement lawsuit against Luminant in federal district court in Dallas, alleging violations of the CAA, including its NSR standards, at our Big Brown and Martin Lake generation facilities. The lawsuit requests (i) the maximum civil penalties available under the CAA to the government of up to \$32,500 to \$37,500 per day for each alleged violation, depending on the date of the alleged violation, and (ii) injunctive relief, including an order to apply for pre-construction permits which may require the installation of best available control technology at the affected units. In August 2015, the district court granted Luminant's motion to dismiss seven of the nine claims asserted by the EPA in the lawsuit.

In January 2017, the EPA dismissed its two remaining claims with prejudice and the district court entered final judgment in Luminant's favor. In March 2017, the EPA and the Sierra Club appealed the final judgment to the Fifth Circuit Court. After the parties filed their respective briefs in the Fifth Circuit Court, the appeal was argued before the Fifth Circuit Court in March 2018. In October 2018, the Fifth Circuit Court affirmed in part, reversed in part, and remanded to the district court. The Fifth Circuit Court's decision held that the district court properly dismissed all of the civil penalties as time-barred. The Fifth Circuit Court further held that the grounds cited by the district court did not support dismissal of the injunctive relief claims at this early stage of the case and remanded the case back to the district court for further consideration. In November 2018, we filed a petition for rehearing en banc on two issues and the EPA's response to that petition is due in February 2019. We believe that we have complied with all requirements of the CAA and intend to continue to vigorously defend against the remaining allegations. An adverse outcome could require substantial capital expenditures that cannot be determined at this time or retirement of the remaining plant at issue, Martin Lake. The retirement of the Big Brown plant should have a favorable impact on this litigation. We cannot predict the outcome of these proceedings, including the financial effects, if any.

Zimmer NOVs — In December 2014, the EPA issued a notice of violation (NOV) alleging violation of opacity standards at the Zimmer facility. The EPA previously had issued NOVs to Zimmer in 2008 and 2010 alleging violations of the CAA, the Ohio State Implementation Plan and the station's air permits including standards applicable to opacity, sulfur dioxide, sulfuric acid mist and heat input. The NOVs remain unresolved. We are unable to predict the outcome of these matters.

Edwards CAA Citizen Suit — In April 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our MISO segment's Edwards facility. In August 2016, the district court granted the plaintiffs' motion for summary judgment on certain liability issues. We filed a motion seeking interlocutory appeal of the court's summary judgment ruling. In February 2017, the appellate court denied our motion for interlocutory appeal. The parties completed briefing on motions for summary judgment on remedy issues in October 2018. In January 2019, the court canceled the bench trial scheduled for March 2019 and denied the parties' motions for summary judgment on remedy issues. In February 2019, the court issued an order that anticipates a trial date at the end of September 2019. We dispute the allegations and will defend the case vigorously. We are unable to predict the outcome of these matters.

Ultimate resolution of any of these CAA matters could have a material adverse impact on our future financial condition, results of operations, and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties, or could result in an order or a decision to retire these plants. While we cannot predict the outcome of these legal proceedings, or estimate a range of costs, they could have a material impact on our results of operations, liquidity or financial condition.

Coal Combustion Residuals (CCR)/Groundwater

The combustion of coal to generate electric power creates large quantities of ash and byproducts that are managed at power generation facilities in dry form in landfills and in wet form in surface impoundments. Each of our coal-fueled plants has at least one CCR surface impoundment. At present, CCR is regulated by the states as solid waste.

Coal Combustion Residuals

The EPA's CCR rule, which took effect in October 2015, establishes minimum federal requirements for existing and new CCR landfills and surface impoundments, as well as inactive CCR surface impoundments. The requirements include location restrictions, structural integrity criteria, groundwater monitoring, operating criteria, liner design criteria, closure and post-closure care, recordkeeping and notification. The rule allows existing CCR surface impoundments to continue to operate for the remainder of their operating life, but generally would require closure if groundwater monitoring demonstrates that the CCR surface impoundment is responsible for exceedances of groundwater quality protection standards or the CCR surface impoundment does not meet location restrictions or structural integrity criteria. The deadlines for beginning and completing closure vary depending on several factors. Several petitions for judicial review of the CCR rule were filed. The Water Infrastructure Improvements for the Nation Act (the WIIN Act), which was enacted in December 2016, provides for EPA review and approval

In July 2018, the EPA published a final rule that amends certain provisions of the CCR rule that the agency issued in 2015. The 2018 revisions extend closure deadlines to October 31, 2020, related to the aquifer location restriction and groundwater monitoring requirements. The 2018 revisions also (1) establish groundwater protection standards for cobalt, lithium, molybdenum and lead (2) allow authorized state programs to waive groundwater monitoring requirements when there is a demonstration of no potential for contaminant migration, and (3) allow the permitting authority to issue certifications in lieu of a qualified professional engineer. The 2018 revisions became effective in August 2018, and we are continuing to evaluate the impact on our CCR facilities. Also, on August 21, 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule. The EPA is expected to undertake further revisions to its CCR regulations in response to the D.C. Circuit Court's ruling. In October 2018, the rule that extends certain closure deadlines to 2020 was challenged in the D.C. Circuit Court. In December 2018, the EPA and petitioners filed cross-motions, with the EPA seeking remand without vacatur and petitioners seeking a partial stay or vacatur of the rule. We have intervened in the litigation and filed a motion in support of the EPA. Briefing on the cross-motions is ongoing. While we cannot predict the impacts of these rule revisions (including whether and if so how the states in which we operate will utilize the authority delegated to the states through the revisions), or estimate a range of reasonably possible costs related to these revisions, the changes that result from these revisions could have a material impact on our results of operations, liquidity or financial condition.

MISO Segment — In 2012, the IEPA issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities' CCR surface impoundments. In 2016, the IEPA approved our closure and post-closure care plans for the Baldwin old east, east, and west fly ash CCR surface impoundments. We are working towards implementation of those closure plans.

At our retired Vermilion facility, which was not subject to the EPA's 2015 CCR rule until the August 2018 court decision, we submitted proposed corrective action plans involving closure of two CCR surface impoundments (*i.e.*, the old east and the north impoundments) to the IEPA in 2012, with revised plans submitted in 2014. In May 2017, in response to a request from the IEPA for additional information regarding the closure of these Vermilion surface impoundments, we agreed to perform additional groundwater sampling and closure options and riverbank stabilizing options. By letter dated January 31, 2018, Prairie Rivers Network provided 60-day notice of its intent to sue our subsidiary Dynegy Midwest Generation, LLC under the federal Clean Water Act for alleged unauthorized discharges from the surface impoundments at our Vermilion facility and alleged related violations of the facility's National Pollutant Discharge Elimination System permit. Prairie Rivers Network filed a citizen suit in May 2018, alleging violations of the Clean Water Act for alleged unauthorized discharges. In August 2018, we filed a motion to dismiss the lawsuit. In November 2018, the district court granted our motion to dismiss and judgment was entered in our favor. Plaintiffs have appealed the judgment to the U.S Court of Appeals for the Ninth Circuit. We dispute the allegations and will vigorously defend our position.

In 2012, the IEPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. We are addressing these CCR surface impoundments in accordance with the federal CCR rule. In June 2018, the IEPA issued a violation notice for alleged seep discharges claimed to be coming from the surface impoundments at our retired Vermilion facility.

In December 2018, the Sierra Club filed a complaint with the IPCB alleging the disposal and storage of coal ash at the Coffeen, Edwards and Joppa generation facilities are causing exceedances of the applicable groundwater standards. We dispute the allegations and will vigorously defend our position.

If remediation measures concerning groundwater are necessary at any of our coal-fueled facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations, and cash flows. At this time, in part because of the revisions to the CCR rule that the EPA published in July 2018 and the D.C. Circuit Court's vacatur and remand of certain provisions of the EPA's 2015 CCR rule, we cannot reasonably estimate the costs, or range of costs, of groundwater remediation, if any, that ultimately may be required. CCR surface impoundment and landfill closure costs, as determined by our operations and environmental services teams, are reflected in our AROs.

Water

The EPA and the environmental regulatory bodies of states in which we operate have jurisdiction over the diversion, impoundment and withdrawal of water for cooling and other purposes and the discharge of wastewater (including storm water) from our facilities. We believe our facilities are presently in material compliance with applicable federal and state requirements relating to these activities. We believe we hold all required permits relating to these activities for facilities in operation and have applied for or obtained necessary permits for facilities under construction. We also believe we can satisfy the requirements necessary to obtain any required permits or renewals.

Cooling Water Intake Structures — Clean Water Act Section 316(b) regulations pertaining to existing water intake structures at large generation facilities became effective in 2014. This provision generally requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. Although the rule does not mandate a certain control technology, it does require site-specific assessments of technology feasibility on a case-by-case basis at the state level.

At this time, we estimate the cost of our compliance with the cooling water intake structure rule will be approximately $16 million, with the majority of the expenditures in 2020 through 2023 at a group of our Illinois generation facilities. Our estimate could change materially depending upon a variety of factors, including site-specific determinations made by states in implementing the rule, the results of impingement and entrainment studies required by the rule, the results of site-specific engineering studies and the outcome of litigation concerning the rule.

Effluent Limitation Guidelines (ELGs) — In November 2015, the EPA revised the ELGs for steam electricity generation facilities, which will impose more stringent standards (as individual permits are renewed) for wastewater streams, flue desulfurization, fly ash, bottom ash and flue gas mercury control. Various parties filed petitions for review of the ELG rule, and the petitions were consolidated in the Fifth Circuit Court. In April 2017, the EPA granted petitions requesting reconsideration of the ELG final rule issued in 2015 and administratively stayed the ELG rule's compliance date deadlines pending ongoing judicial review of the rule. The legal challenges pertaining to bottom ash transport water, flue gas desulfurization wastewater and gasification wastewater have been suspended while the EPA reconsiders the rules.

The EPA issued a final rule in September 2017 postponing the earliest compliance dates in the ELG rule for bottom ash transport water and flue-gas desulfurization wastewater by two years, from November 1, 2018 to November 1, 2020.

Given the EPA's decision to reconsider the bottom ash transport water and flue gas desulfurization wastewater provisions of the ELG rule, the rule postponing the ELG rule's earliest compliance dates for those provisions, and the intertwined relationship of the ELG rule with the CCR rule discussed below, which is also being reconsidered by the EPA, as well as pending legal challenges concerning both rules, substantial uncertainty exists regarding our projected capital expenditures for ELG compliance, including the timing of such expenditures. While we cannot predict the outcome of this matter, or estimate a range of costs, it could have a material impact on our results of operations, liquidity or financial condition.

Radioactive Waste

The nuclear industry has developed ways to store used nuclear fuel on site at nuclear generation facilities, primarily using dry cask storage, since there are no facilities for reprocessing or disposal of used nuclear fuel currently in operation in the U.S. Luminant stores its used nuclear fuel on-site in storage pools or dry cask storage facilities and believes its on-site used nuclear fuel storage capability is sufficient for the foreseeable future.

Environmental Capital Expenditures

Capital expenditures for our environmental projects totaled $13 million in the year ended December 31, 2018 and are expected to total approximately $35 million in the year ended December 31, 2019 for environmental control equipment to comply with regulatory requirements.

	Year Ended December 31,	
	2018	Estimated 2019
ERCOT	$ 9	$ 6
PJM	3	14
MISO	1	14
CAISO	—	1
Total	$ 13	$ 35

Item 1A. RISK FACTORS

Important factors, in addition to others specifically addressed in Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*, that could have a material adverse effect on our business, results of operations, liquidity and financial condition, or could cause results or outcomes to differ materially from those contained in or implied by any forward-looking statement in this Annual Report, are described below. There may be further risks and uncertainties that are not currently known or that are not currently believed to be material that may adversely affect our business, results of operations, liquidity, financial condition and prospects and the market price of our common stock in the future. The realization of any of these factors could cause investors in our common stock to lose all or a substantial portion of their investment.

Market, Financial and Economic Risks

Our revenues, results of operations and operating cash flows generally may be impacted by price fluctuations in the wholesale power market and other market factors beyond our control.

We are not guaranteed any rate of return on capital investments in our businesses. We conduct integrated power generation and retail electricity activities, focusing on power generation, wholesale electricity sales and purchases, retail sales of electricity and services to end users and commodity risk management. Our wholesale and retail businesses are to some extent countercyclical in nature, particularly for the wholesale power and ancillary services supplied to the retail business. However, we do have a wholesale power position that exceeds the overall load requirements of our retail business and is subject to wholesale power price moves. As a result, our revenues, results of operations and operating cash flows depend in large part upon wholesale market prices for electricity, natural gas, uranium, lignite, coal, fuel and transportation in our regional markets and other competitive markets and upon prevailing retail electricity rates, which may be impacted by, among other things, actions of regulatory authorities. Market prices for power, capacity, ancillary services, natural gas, coal and oil are unpredictable and may fluctuate substantially over relatively short periods of time. Unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility due to supply and demand imbalances, especially in the day-ahead and spot markets. Demand for electricity can fluctuate dramatically, creating periods of substantial under- or over-supply. Over-supply can also occur as a result of the construction of new power plants, as we have observed in recent years. During periods of over-supply, electricity prices might be depressed. Also, at times there may be political pressure, or pressure from regulatory authorities with jurisdiction over wholesale and retail energy commodity and transportation rates, to impose price limitations, bidding rules and other mechanisms to address volatility and other issues in these markets.

The majority of our facilities operate as "merchant" facilities without long-term power sales agreements. As a result, we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other wholesale and retail power markets on a short-term basis and are not guaranteed any rate of return on our capital investments. Consequently, there can be no assurance that we will be able to sell any or all of the electric energy, capacity or ancillary services from those facilities at commercially attractive rates or that our facilities will be able to operate profitably. We depend, in large part, upon prevailing market prices for power, capacity and fuel. Given the volatility of commodity power prices, to the extent we do not secure long-term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to volatility, and our financial condition, results of operations and cash flows could be materially adversely affected.

We purchase natural gas, coal, oil and nuclear fuel for our generation facilities, and higher than expected fuel costs or volatility in these fuel markets may have an adverse impact on our costs, revenues, results of operations, financial condition and cash flows.

We rely on natural gas, coal and oil to fuel the majority of our power generation facilities. Delivery of these fuels to the facilities is dependent upon the continuing financial viability of contractual counterparties as well as upon the infrastructure (including rail lines, rail cars, barge facilities, roadways, riverways and natural gas pipelines) available to serve each generation facility. As a result, we are subject to the risks of disruptions or curtailments in the production of power at our generation facilities if no fuel is available at any price or if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure.

We have sold forward a substantial portion of our expected power sales in the next one to two years in order to lock in long-term prices. In order to hedge our obligations under these forward power sales contracts, we have entered into long-term and short-term contracts for the purchase and delivery of fuel. Many of the forward power sales contracts do not allow us to pass through changes in fuel costs or discharge the power sale obligations in the case of a disruption in fuel supply due to force majeure events or the default of a fuel supplier or transporter. Fuel costs (including diesel, natural gas, lignite, coal and nuclear fuel) may be volatile, and the wholesale price for electricity may not change at the same rate as changes in fuel costs, and disruptions in our fuel supplies may therefore require us to find alternative fuel sources at higher costs, to find other sources of power to deliver to counterparties at a higher cost, or to pay damages to counterparties for failure to deliver power as contracted. In addition, we purchase and sell natural gas and other energy related commodities, and volatility in these markets may affect costs incurred in meeting obligations. Further, any changes in the costs of coal, fuel oil, natural gas or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. If we are unable to procure fuel for physical delivery at prices we consider favorable, our financial condition, results of operations and cash flows could be materially adversely affected.

We also buy significant quantities of fuel on a short-term or spot market basis. Prices for all of our fuels fluctuate, sometimes rising or falling significantly over a relatively short period of time. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. This may have a material adverse effect on our financial performance. Volatility in market prices for fuel and electricity may result from, among other factors:

- demand for energy commodities and general economic conditions;
- volatility in commodity prices and the supply of commodities, including but not limited to natural gas, coal and oil;
- volatility in market heat rates;
- volatility in coal and rail transportation prices;
- volatility in nuclear fuel and related enrichment and conversion services;
- disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;
- severe or unexpected weather conditions, including drought and limitations on access to water;
- seasonality;
- changes in electricity and fuel usage resulting from conservation efforts, changes in technology or other factors;
- illiquidity in the wholesale electricity or other commodity markets;
- transmission or transportation disruptions, constraints, inoperability or inefficiencies, or other changes in power transmission infrastructure;
- development and availability of new fuels, new technologies and new forms of competition for the production and storage of power, including competitively priced alternative energy sources or storage;
- changes in market structure and liquidity;
- changes in the way we operate our facilities, including curtailed operation due to market pricing, environmental regulations and legislation, safety or other factors;
- changes in generation capacity or efficiency;
- outages or otherwise reduced output from our generation facilities or those of our competitors;
- changes in electric capacity, including the addition of new supplies of power as a result of the development of new plants, expansion of existing plants, the continued operation of uneconomic power plants due to federal, state or local subsidies, or additional transmission capacity;
- our creditworthiness and liquidity and the willingness of fuel suppliers and transporters to do business with us;
- changes in the credit risk or payment practices of market participants;
- changes in production and storage levels of natural gas, lignite, coal, uranium, diesel and other refined products;
- natural disasters, wars, sabotage, terrorist acts, embargoes and other catastrophic events, and
- changes in law, including judicial decisions, federal, state and local energy, environmental and other regulation and legislation.

We may be forced to retire or idle underperforming generation units, which could result in significant costs and have an adverse effect on our operating results.

During 2018, we retired our Monticello, Sandow 4, Sandow 5, Big Brown, Killen, Stuart and Northeastern units. A sustained decrease in the financial results from, or the value of, our generation units ultimately could result in the retirement or idling of certain other generation units. In recent years, we have operated certain of our lignite- and coal-fueled generation assets only during parts of the year that have higher electricity demand and, therefore, higher related wholesale electricity prices.

Our assets or positions cannot be fully hedged against changes in commodity prices and market heat rates, and hedging transactions may not work as planned or hedge counterparties may default on their obligations.

Our hedging activities do not fully protect us against the risks associated with changes in commodity prices, most notably electricity and natural gas prices, because of the expected useful life of our generation assets and the size of our position relative to the duration of available markets for various hedging activities. Generally, commodity markets that we participate in to hedge our exposure to electricity prices and heat rates have limited liquidity after two to three years. Further, our ability to hedge our revenues by utilizing cross-commodity hedging strategies with natural gas hedging instruments is generally limited to a duration of four to five years. To the extent we have unhedged positions, fluctuating commodity prices and/or market heat rates can materially impact our results of operations, cash flows, liquidity and financial condition, either favorably or unfavorably.

To manage our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge portions of purchase and sale commitments, fuel requirements and inventories of natural gas, lignite, coal, diesel fuel, uranium and refined products, and other commodities, within established risk management guidelines. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sale contracts, futures, financial swaps and option contracts traded in over-the-counter markets or on exchanges. Although we devote a considerable amount of time and effort to the establishment of risk management procedures, as well as the ongoing review of the implementation of these procedures, the procedures in place may not always function as planned and cannot eliminate all the risks associated with these activities. For example, we hedge the expected needs of our wholesale and retail customers, but unexpected changes due to weather, natural disasters, consumer behavior, market constraints or other factors could cause us to purchase electricity to meet unexpected demand in periods of high wholesale market prices or resell excess electricity into the wholesale market in periods of low prices. As a result of these and other factors, risk management decisions may have a material adverse effect on us.

Based on economic and other considerations, we may not be able to, or we may decide not to, hedge the entire exposure of our operations from commodity price risk. To the extent we do not hedge against commodity price risk and applicable commodity prices change in ways adverse to us, we could be materially and adversely affected. To the extent we do hedge against commodity price risk, those hedges may ultimately prove to be ineffective.

With the tightening of credit markets that began in 2008 and the expansion of regulatory oversight through various financial reforms, there has been a decline in the number of market participants in the wholesale energy commodities markets, resulting in less liquidity. Notably, participation by financial institutions and other intermediaries (including investment banks) in such markets has declined. Extended declines in market liquidity could adversely affect our ability to hedge our financial exposure to desired levels.

To the extent we engage in hedging and risk management activities, we are exposed to the credit risk that counterparties that owe us money, energy or other commodities as a result of these activities will not perform their obligations to us. Should the counterparties to these arrangements fail to perform, we could be forced to enter into alternative hedging arrangements or honor the underlying commitment at then-current market prices. Additionally, our counterparties may seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows. In such event, we could incur losses or forgo expected gains in addition to amounts, if any, already paid to the counterparties. Market participants in the RTOs and ISOs in which we operate are also exposed to risks that another market participant may default on its obligations to pay such RTO or ISO for electricity or services taken, in which case such costs, to the extent not offset by posted security and other protections available to such RTO or ISO, may be allocated to various non-defaulting RTO or ISO market participants, including us.

We do not apply hedge accounting to our commodity derivative transactions, which may cause increased volatility in our quarterly and annual financial results.

We engage in economic hedging activities to manage our exposure related to commodity price fluctuations through the use of financial and physical derivative contracts for commodities. These derivatives are accounted for in accordance with GAAP, which requires that we record all derivatives on the balance sheet at fair value with changes in fair value immediately recognized in earnings as unrealized gains or losses. GAAP permits an entity to designate qualifying derivative contracts as normal purchases and sales. If designated, those contracts are not recorded at fair value. GAAP also permits an entity to designate qualifying derivative contracts in a hedge accounting relationship. If a hedge accounting relationship is used, a significant portion of the changes in fair value is not immediately recognized in earnings. We have chosen not to apply hedge accounting to our commodity contracts and we have chosen to elect normal purchase normal sales in only limited cases, such as our retail sales contracts. As a result, our quarterly and annual financial results in accordance with GAAP are subject to significant fluctuations caused by changes in forward commodity prices.

Competition, change in market structure, and/or state or federal interference in the wholesale and retail power markets, together with subsidized generation, may have a material adverse effect on our financial condition, results of operations and cash flows.

Our generation and competitive retail businesses rely on a competitive wholesale marketplace. The competitive wholesale marketplace may be undermined by changes in market structure and out-of-market subsidies provided by federal or state entities, including bailouts of uneconomic plants, imports of power from Canada, renewable mandates or subsidies, as well as out-of-market payments to new generators.

Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions in the sale of electric energy, capacity and ancillary services, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generating facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance and/or subsidize renewable generation increases competition from these types of facilities and out-of-market subsidies to existing or new generation can undermine the competitive wholesale marketplace, which can lead to premature retirement of existing facilities, including those owned by us.

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources or experience in these areas. Over time, some of our plants may become unable to compete because of subsidized generation, including public utility commission supported power purchase agreements, and the construction of new plants. Such new plants could have a number of advantages including: more efficient equipment, newer technology that could result in fewer emissions or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities.

Other factors may contribute to increased competition in wholesale power markets. New forms of capital and competitors have entered the industry, including financial investors who perceive that asset values are at levels below their true replacement value. As a result, a number of generation facilities in the U.S. are now owned by lenders and investment companies. Furthermore, mergers and asset reallocations in the industry could create powerful new competitors. Under any scenario, we anticipate that we will face competition from numerous companies in the industry. Certain federal and state entities in jurisdictions in which we operate have either enacted or are considering regulations or legislation to subsidize otherwise uneconomic plants and attempt to incent the development of new renewable resources as well as increase energy efficiency investments. Continued subsidies (or increases thereto) to our competitors could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, our retail marketing efforts compete for customers in a competitive environment, which impacts the margins that we can earn on the volumes we are able to serve. Further, with retail competition, it is easier for residential customers where we serve load to switch to and from competitive electricity generation suppliers for their energy needs. The volatility and uncertainty that results from such mobility may have material adverse effects on our financial condition, results of operations and cash flows. For example, if fewer customers switch to another supplier than anticipated, the load we must serve will be greater than anticipated and, if market prices of fuel have increased, our costs will increase more than expected due to the need to go to the market to cover the incremental supply obligation. If more customers switch to another supplier than anticipated, the load we must serve will be lower than anticipated and, if market prices of electricity have decreased, our operating results could suffer.

Our results of operations and financial condition could be materially and adversely affected if energy market participants continue to construct additional generation facilities (i.e., new-build) or expand or enhance existing generation facilities despite relatively low power prices and such additional generation capacity results in a reduction in wholesale power prices.

Given the overall attractiveness of certain of the markets in which we operate and certain tax benefits associated with renewable energy, among other matters, energy market participants have continued to construct new generation facilities (*i.e.*, new-build) or invest in enhancements or expansions of existing generation facilities despite relatively low wholesale power prices. If this market dynamic continues, our results of operations and financial condition could be materially and adversely affected if such additional generation capacity results in an over-supply of electricity that causes a reduction in wholesale power prices.

Unauthorized hedging and related activities by our employees could result in significant losses.

We have various internal policies, processes, and controls designed to monitor hedging activities and positions. These policies, processes, and controls are designed, in part, to prevent unauthorized purchases or sales of products by our employees or alert our risk management teams of any trades that have not been entered into our risk management systems. We cannot assure, however, that these steps will detect and prevent inaccurate reporting and all potential violations of our risk management policies, processes, and controls, particularly if deception or other intentional misconduct is involved. A significant policy violation that is not detected could result in a substantial financial loss.

Our risk management policies cannot fully eliminate the risk associated with our commodity hedging activities.

Our operations and other commodity hedging activities expose us to risks of commodity price movements. We attempt to manage this exposure by entering into commodity hedging transactions and establishing risk management policies and procedures. These risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. As a result, we cannot fully predict the impact that our commodity hedging activities and risk management decisions may have on our business and/or financial condition, results of operations and cash flows.

Economic downturns would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services by commercial and industrial customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible customer balances, which would negatively impact our overall sales and cash flows. Additionally, prolonged economic downturns that negatively impact our financial condition, results of operations and cash flows could result in future material impairment charges to write down the carrying value of certain assets to their respective fair values.

Our liquidity needs could be difficult to satisfy, particularly during times of uncertainty in the financial markets or during times of significant fluctuation in commodity prices, and we may be unable to access capital on favorable terms or at all in the future, which could have a material adverse effect on us. We currently maintain non-investment grade credit ratings that could negatively affect our ability to access capital on favorable terms or result in higher collateral requirements, particularly if our credit ratings were to be downgraded in the future.

Our businesses are capital intensive. In general, we rely on access to financial markets and credit facilities as a significant source of liquidity for our capital requirements and other obligations not satisfied by cash-on-hand or operating cash flows. The inability to raise capital or to access credit facilities, particularly on favorable terms, could adversely impact our liquidity and our ability to meet our obligations or sustain and grow our businesses and could increase capital costs and collateral requirements, any of which could have a material adverse effect on us.

Our access to capital and the cost and other terms of acquiring capital are dependent upon, and could be adversely impacted by, various factors, including:

- general economic and capital markets conditions, including changes in financial markets that reduce available liquidity or the ability to obtain or renew credit facilities on favorable terms or at all;
- conditions and economic weakness in the U.S. power markets;
- regulatory developments;
- changes in interest rates;
- a deterioration, or perceived deterioration, of our creditworthiness, enterprise value or financial or operating results;
- a reduction in Vistra Energy's or its applicable subsidiaries' credit ratings;
- our level of indebtedness and compliance with covenants in our debt agreements;
- a deterioration of the creditworthiness or bankruptcy of one or more lenders or counterparties under our credit facilities that affects the ability of such lender(s) to make loans to us;
- security or collateral requirements;
- general credit availability from banks or other lenders for us and our industry peers;
- investor confidence in the industry and in us and the wholesale electricity markets in which we operate;
- volatility in commodity prices that increases credit requirements;
- a material breakdown in our risk management procedures;
- the occurrence of changes in our businesses;
- disruptions, constraints, or inefficiencies in the continued reliable operation of our generation facilities, and
- changes in or the operation of provisions of tax and regulatory laws.

In addition, we currently maintain non-investment grade credit ratings. As a result, we may not be able to access capital on terms (financial or otherwise) as favorable as companies that maintain investment-grade credit ratings or we may be unable to access capital at all at times when the credit markets tighten. In addition, our non-investment grade credit ratings may result in counterparties requesting collateral support (including cash or letters of credit) in order to enter into transactions with us.

A downgrade in long-term debt ratings generally causes borrowing costs to increase and the potential pool of investors to shrink and could trigger liquidity demands pursuant to contractual arrangements. Future transactions by Vistra Energy or any of its subsidiaries, including the issuance of additional debt, could result in a temporary or permanent downgrade in our credit ratings.

Our indebtedness could adversely affect our ability in the future to raise additional capital to fund our operations. It could also expose us to the risk of increased interest rates and limit our ability to react to changes in the economy, or our industry, as well as impact our cash available for distribution.

In connection with the Merger, we assumed all of Dynegy's outstanding indebtedness. As of December 31, 2018, we had approximately $11.1 billion of total indebtedness and approximately $10.4 billion of indebtedness net of cash. Our debt could have negative consequences for our financial condition including:

- increasing our vulnerability to general economic and industry conditions;
- requiring a substantial portion of our cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to pay dividends to holders of our common stock or to fund our operations, capital expenditures and future business opportunities;
- limiting our ability to enter into long-term power sales or fuel purchases which require credit support;
- limiting our ability to fund operations or future acquisitions;
- restricting our ability to make distributions or pay dividends with respect to our capital stock and the ability of our subsidiaries to make distributions to us, in light of restricted payment and other financial covenants in our credit facilities and other financing agreements;
- inhibiting the growth of our stock price;
- exposing us to the risk of increased interest rates because certain of our borrowings, including borrowings under the Vistra Operations Credit Facilities, are at variable rates of interest;
- limiting our ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes, and
- limiting our ability to adjust to changing market conditions and placing us at a competitive disadvantage compared to our competitors who may have less debt.

We may not be successful in obtaining additional capital for these or other reasons. Furthermore, we may be unable to refinance or replace our existing indebtedness on favorable terms or at all upon the expiration or termination thereof. Our failure to obtain additional capital or enter into new or replacement financing arrangements when due may constitute a default under such existing indebtedness and may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The Vistra Operations Credit Facilities impose restrictions on us and any failure to comply with these restrictions could have a material adverse effect on us.

The Vistra Operations Credit Facilities contain restrictions that could adversely affect us by limiting our ability to plan for, or react to, market conditions or to meet our capital needs and could result in an event of default under the Vistra Operations Credit Facilities. The Vistra Operations Credit Facilities contain events of default customary for financings of this type. If we fail to comply with the covenants in the Vistra Operations Credit Facilities and are unable to obtain a waiver or amendment, or a default exists and is continuing, the lenders under such agreements could give notice and declare outstanding borrowings thereunder immediately due and payable. Any such acceleration of outstanding borrowings could have a material adverse effect on us.

Certain of our obligations are required to be secured by letters of credit or cash, which increase our costs. If we are unable to provide such security, it may restrict our ability to conduct our business, which could have a material adverse effect on us.

We undertake certain hedging and commodity activities and enter into certain financing arrangements with various counterparties that require cash collateral or the posting of letters of credit which are at risk of being drawn down in the event we default on our obligations. We currently use margin deposits, prepayments and letters of credit as credit support for commodity procurement and risk management activities. Future cash collateral requirements may increase based on the extent of our involvement in standard contracts and movements in commodity prices, and also based on our credit ratings and the general perception of creditworthiness in the markets in which we operate. In the case of commodity arrangements, the amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in our being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of our strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than we anticipate or will be able to meet. Without a sufficient amount of working capital to post as collateral, we may not be able to manage price volatility effectively or to implement our strategy. An increase in the amount of letters of credit or cash collateral required to be provided to our counterparties may have a material adverse effect on us.

We may be unable to successfully integrate the operations of the legacy Dynegy assets with our existing operations or to realize targeted cost savings, revenues and other anticipated benefits of the Merger.

The success of the Merger will depend, in part, on our ability to realize the anticipated benefits and synergies from integrating Dynegy's assets with our existing retail and generation business. To realize these anticipated benefits, the businesses must be successfully combined.

We may be required to make unanticipated capital expenditures or investments in order to maintain, integrate, improve or sustain the assets' operations, or take unexpected write-offs or impairment charges resulting from the Merger. Further, we may be subject to unanticipated or unknown liabilities relating to the legacy Dynegy assets and operations. If any of these factors occur or limit our ability to integrate the businesses successfully or on a timely basis, the expectations regarding our future financial condition and results of operations following the Merger might not be met.

In addition, we continue to evaluate our estimates of synergies to be realized from, and refine the fair value accounting allocations associated with, the Merger. Accordingly, actual cost-savings, the costs required to realize the cost-savings, and the source of the cost-savings could differ materially from our estimates, and we cannot ensure that we will achieve the full amount of cost-savings on the schedule anticipated or at all.

Finally, we may not be able to achieve the targeted operating or long-term strategic benefits of the Merger. If the combined businesses are not able to achieve our objectives, or are not able to achieve our objectives on a timely basis, the anticipated benefits of the Merger may not be realized fully or at all. An inability to realize the full extent of, or any of, the anticipated benefits of the Merger, as well as any delays encountered in the integration process, could have an adverse effect on our financial condition, results of operations and cash flows.

The allocation of the purchase price to the value amounts recognized for the assets acquired and liabilities assumed related to the Merger as of the Merger Date is preliminary in nature and could differ materially from our initial purchase price allocation.

Based on the opening price of our common stock on the Merger Date, the preliminary purchase price of Dynegy in the Merger was approximately $2.3 billion as of December 31, 2018. The purchase price allocation is substantially complete, but is dependent upon final valuation determinations, which may materially change from our current estimates. The preliminary purchase price allocation reflected in our consolidated financial statements represents our current best estimates for property plant and equipment, identifiable intangible assets and liabilities, goodwill, inventories, asset retirement obligations, contingent liabilities and deferred taxes. We currently expect the final purchase price allocation will be completed no later than the first quarter of 2019 and goodwill will be allocated to the related reporting units at that time.

The proposed acquisition of Crius may not be completed in a timely fashion or at all, and the failure to successfully integrate the Crius business and operations in the expected time frame may adversely affect our future results.

Completion of the Crius Acquisition is subject to satisfaction of a number of conditions, including the receipt of unitholder approval and certain regulatory approvals for which the timing cannot be predicted. The expiration or termination of the applicable waiting periods, and any extension of the waiting periods, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and approval by the FERC regulations may take considerable time. If Vistra Energy is not able to successfully integrate Crius' business and operations, or if there are additional and unforeseen expenses or delays in combining the businesses, realizing any anticipated synergies, accelerating retail growth expansion or optimizing existing fleet and operational efficiencies, the anticipated benefits of the Crius Acquisition may not be realized fully or at all or may take longer to realize than expected.

We may not be able to complete future acquisitions or successfully integrate future acquisitions into our business, which could result in unanticipated expenses and losses.

As part of our growth strategy, including our desire to grow our retail platform, we may pursue acquisitions of assets or operating entities. Our ability to continue to implement this component of our growth strategy will be limited by our ability to identify appropriate acquisition or joint venture candidates and our financial resources, including available cash and access to capital. Any expense incurred in completing acquisitions or entering into joint ventures, the time it takes to integrate an acquisition or our failure to integrate acquired businesses successfully could result in unanticipated expenses and losses. Furthermore, we may not be able to fully realize the anticipated benefits from any future acquisitions or joint ventures we may pursue. In addition, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and expenses and may require significant financial resources that would otherwise be available for the execution of our business strategy.

Circumstances associated with potential divestitures could adversely affect our results of operations and financial condition.

In evaluating our business and the strategic fit of our various assets, we may determine to sell one or more of such assets. Despite a decision to divest an asset, we may encounter difficulty in finding a buyer willing to purchase the asset at an acceptable price and on acceptable terms and in a timely manner. In addition, a prospective buyer may have difficulty obtaining financing. Divestitures could involve additional risks, including:

- difficulties in the separation of operations and personnel;
- the need to provide significant ongoing post-closing transition support to a buyer;
- management's attention may be temporarily diverted;
- the retention of certain current or future liabilities in order to induce a buyer to complete a divestiture;
- the obligation to indemnify or reimburse a buyer for certain past liabilities of a divested asset;
- the disruption of our business, and
- potential loss of key employees.

We may not be successful in managing these or any other significant risks that we may encounter in divesting any asset, which could adversely affect our results of operations and financial condition.

If our goodwill, intangible assets, or long-lived assets become impaired, we may be required to record a significant charge to earnings.

We have significant goodwill, intangible assets and long-lived assets recorded on our balance sheet. In accordance with U.S. GAAP, goodwill and non-amortizing intangible assets are required to be tested for impairment at least annually. Additionally, we review goodwill, our intangible assets and long-lived assets for impairment when events or changes in circumstances indicate the carrying value of the asset may not be recoverable. Factors that may be considered include a decline in future cash flows, slower growth rates in the energy industry, and a sustained decrease in the price of our common stock.

We performed our annual assessment of goodwill and non-amortizing intangibles and determined that no impairment was required. However, impairment assessments will be performed in future periods and may result in an impairment loss, which could be material.

Issuances or acquisitions of our common stock, or sales or dispositions of our common stock by stockholders, that result in an ownership change as defined in Internal Revenue Code (IRC) §382 could further limit our ability to use our federal net operating losses or alternative minimum tax credits to offset our future taxable income.

If an "ownership change," as defined in Section 382 of the IRC (IRC §382) occurs, the amount of NOLs and AMT credits that could be used in any one year following such ownership change could be substantially limited. In general, an "ownership change" would occur when there is a greater than 50 percentage point increase in ownership of a company's stock by stockholders, each of which owns (or is deemed to own under IRC §382) 5 percent or more of such company's stock. Given IRC §382's broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in our stock that is outside our control. Vistra Energy acquired NOLs and AMT credits from its merger with Dynegy, however, Vistra Energy's use of such attributes is limited under IRC §382 because the merger constituted an "ownership change" with respect to Dynegy. If there is an "ownership change" with respect to Vistra Energy (including by the normal trading activity of greater than 5% shareholders), the utilization of all NOLs and AMT credits existing at that time would be subject to additional annual limitations based upon a formula provided under IRC §382 that is based on the fair market value of the Company and prevailing interest rates at the time of the ownership change.

Recent U.S. tax legislation may materially adversely affect Vistra Energy's financial condition, results of operations and cash flows.

On December 22, 2017, President Trump signed into law a comprehensive tax reform bill (the TCJA), that significantly reforms the Internal Revenue Code. The TCJA, among other things, contains significant changes to corporate taxation, including a reduction of the corporate income tax rate, a partial limitation on the deductibility of business interest expense, limitation of the deduction for certain net operating losses to 80% of current year taxable income, an indefinite net operating loss carryforward, immediate deductions for certain new investments instead of deductions for depreciation expense over time and the modification or repeal of many business deductions and credits. While we expect a beneficial impact from the TCJA from the reduction in corporate tax rates and immediate deductions for certain new investments, we continue to examine the tax reform legislation, as its overall impact is uncertain, and note that certain provisions of the TCJA or its interaction with existing law could adversely affect the Company's business and financial condition. The impact of this tax reform legislation on our stockholders is also uncertain and could be adverse.

We may be responsible for U.S. federal and state income tax liabilities that relate to the PrefCo Preferred Stock Sale and Spin-Off.

Pursuant to the Tax Matters Agreement, the parties thereto have agreed to take certain actions and refrain from taking certain actions in order to preserve the intended tax treatment of the Spin-Off and to indemnify the other parties to the extent a breach of such covenant results in additional taxes to the other parties. If we breach such a covenant (or, in certain circumstances, if our stockholders or creditors of our Predecessor take or took certain actions that result in the intended tax treatment of the Spin-Off not to be preserved), we may be required to make substantial indemnification payments to the other parties to the Tax Matters Agreement.

The Tax Matters Agreement also allocates the responsibility for taxes for periods prior to the Spin-Off between EFH Corp. and us. For periods prior to the Spin-Off, (i) Vistra Energy is generally required to reimburse EFH Corp. with respect to any taxes paid by EFH Corp. that are attributable to us and (ii) EFH Corp. is generally required to reimburse us with respect to any taxes paid by us that are attributable to EFH Corp.

We are also required to indemnify EFH Corp. against certain taxes in the event the IRS or another taxing authority successfully challenges the amount of gain relating to the PrefCo Preferred Stock Sale or the amount or allowance of EFH Corp.'s net operating loss deductions.

Our indemnification obligations to EFH Corp. are not limited by any maximum amount. If we are required to indemnify EFH Corp. or such other persons under the circumstances set forth in the Tax Matters Agreement, we may be subject to substantial liabilities.

We are required to pay the holders of TRA Rights for certain tax benefits, which amounts are expected to be substantial.

On the Effective Date, we entered into the TRA with American Stock Transfer & Trust Company, LLC, as the transfer agent. Pursuant to the TRA, we issued beneficial interests in the rights to receive payments under the TRA (TRA Rights) to the first lien creditors of our Predecessor to be held in escrow for the benefit of the first lien creditors of our Predecessor entitled to receive such TRA Rights under the Plan of Reorganization. Our financial statements reflect a liability of $420 million as of December 31, 2018 related to these future payment obligations (see Note 10 to the Financial Statements). This amount is based on certain assumptions as described more fully in the notes to the financial statements and the actual payments made under the TRA could be materially different than this estimate.

The TRA provides for the payment by us to the holders of TRA Rights of 85% of the amount of cash savings, if any, in U.S. federal, state and local income tax that we and our subsidiaries actually realize as a result of our use of (a) the tax basis step up attributable to the PrefCo Preferred Stock Sale, (b) the entire tax basis of the assets acquired as a result of the purchase and sale agreement, dated as of November 25, 2015 by and between La Frontera Ventures, LLC and Luminant, and (c) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA. The amount and timing of any payments under the TRA will vary depending upon a number of factors, including the amount and timing of the taxable income we generate in the future and the tax rate then applicable, our use of loss carryovers and the portion of our payments under the TRA constituting imputed interest.

Although we are not aware of any issue that would cause the IRS to challenge the tax benefits that are the subject of the TRA, recipients of the payments under the TRA will not be required to reimburse us for any payments previously made if such tax benefits are subsequently disallowed. As a result, in such circumstances, Vistra Energy could make payments under the TRA that are greater than its actual cash tax savings. Any amount of excess payment can be used to reduce future TRA payments, but cannot be immediately recouped, which could adversely affect our liquidity.

Because Vistra Energy is a holding company with no operations of its own, its ability to make payments under the TRA is dependent on the ability of its subsidiaries to make distributions to it. To the extent that Vistra Energy is unable to make payments under the TRA because of the inability of its subsidiaries to make distributions to us for any reason, such payments will be deferred and will accrue interest until paid, which could adversely affect our results of operations and could also affect our liquidity in periods in which such payments are made.

The payments we will be required to make under the TRA could be substantial.

We may be required to make an early termination payment to the holders of TRA Rights under the TRA.

The TRA provides that, in the event that Vistra Energy breaches any of its material obligations under the TRA, or upon certain mergers, asset sales, or other forms of business combination or certain other changes of control, the transfer agent under the TRA may treat such event as an early termination of the TRA, in which case Vistra Energy would be required to make an immediate payment to the holders of the TRA Rights equal to the present value (at a discount rate equal to LIBOR plus 100 basis points) of the anticipated future tax benefits based on certain valuation assumptions.

As a result, upon any such breach or change of control, we could be required to make a lump sum payment under the TRA before we realize any actual cash tax savings and such lump sum payment could be greater than our future actual cash tax savings.

The aggregate amount of these accelerated payments could be materially more than our estimated liability for payments made under the TRA set forth in our financial statements. Based on this estimation, our obligations under the TRA could have a substantial negative impact on our liquidity.

We are potentially liable for U.S. income taxes of the entire EFH Corp. consolidated group for all taxable years in which we were a member of such group.

Prior to the Spin-Off, EFH Corporate Services Company, EFH Properties Company and certain other subsidiary corporations were included in the consolidated U.S. federal income tax group of which EFH Corp. was the common parent (EFH Corp. Consolidated Group). In addition, pursuant to the private letter ruling from the IRS that we received in connection with the Spin-Off, Vistra Energy will be considered a member of the EFH Corp. Consolidated Group immediately prior to the Spin-Off. Under U.S. federal income tax laws, any corporation that is a member of a consolidated group at any time during a taxable year is severally liable for the group's entire federal income tax liability for the entire taxable year. In addition, entities that are disregarded for U.S. federal income tax purposes may be liable as successors under common law theories or under certain regulations to the extent corporations transferred assets to such entities or merged or otherwise consolidated into such entities, whether under state law or purely as a matter of federal income tax law. Thus, notwithstanding any contractual rights to be reimbursed or indemnified by EFH Corp. pursuant to the Tax Matters Agreement, to the extent EFH Corp. or other members of the EFH Corp. Consolidated Group fail to make any U.S. federal income tax payments required of them by law in respect of taxable years for which the Company or any subsidiary noted above was a member of the EFH Corp. Consolidated Group, the Company or such subsidiary may be liable for the shortfall. At such time, we may not have sufficient cash on hand to satisfy such payment obligation.

Our ability to claim a portion of depreciation deductions may be limited for a period of time.

Under the Internal Revenue Code of 1986, as amended, a corporation's ability to utilize certain tax attributes, including depreciation, may be limited following an ownership change if the corporation's overall asset tax basis exceeds the overall fair market value of its assets (after making certain adjustments). The Spin-Off resulted in an ownership change for the Company and it is expected that the overall tax basis of our assets may have exceeded the overall fair market value of our assets at such time. As a result, there may be a limitation on our ability to claim a portion of our depreciation deductions for a five-year period. This limitation could have a material impact on our tax liabilities and on our obligations under the TRA Rights. In addition, any future ownership change of Vistra Energy following Emergence could likewise result in additional limitations on our ability to use certain tax attributes existing at the time of any such ownership change and have an impact on our tax liabilities and on our obligations under the TRA.

Regulatory and Legislative Risks

Our businesses are subject to ongoing complex governmental regulations and legislation that have impacted, and may in the future impact, our businesses, results of operations, liquidity and financial condition.

Our businesses operate in changing market environments influenced by various state and federal legislative and regulatory initiatives regarding the restructuring of the energy industry, including competition in power generation and sale of electricity. Although we attempt to comply with changing legislative and regulatory requirements, there is a risk that we will fail to adapt to any such changes successfully or on a timely basis.

Our businesses are subject to numerous state and federal laws (including PURA, the Federal Power Act, the Atomic Energy Act, the Public Utility Regulatory Policies Act of 1978, the Clean Air Act (CAA), the Energy Policy Act of 2005 and the Dodd-Frank Wall Street Reform and Consumer Protection Act), changing governmental policy and regulatory actions (including those of the FERC, the NERC, the RCT, the MSHA, the EPA, the NRC, CFTC, state public utility commissions and state environmental regulatory agencies), and the rules, guidelines and protocols of ERCOT, CAISO, ISO-NE, MISO, NYISO and PJM with respect to various matters, including, but not limited to, market structure and design, operation of nuclear generation facilities, construction and operation of other generation facilities, development, operation and reclamation of lignite mines, recovery of costs and investments, decommissioning costs, market behavior rules, present or prospective wholesale and retail competition and environmental matters. We, along with other market participants, are subject to electricity pricing constraints and market behavior and other competition-related rules and regulations under PURA. Changes in, revisions to, or reinterpretations of, existing laws and regulations may have a material adverse effect on us.

Dynegy's legacy business operates in a number of states and markets outside of our historical operations. As a result of the Merger, we became subject to the regulatory requirements of such markets, including CAISO, ISO-NE, MISO, NYISO and PJM. Because we have historically not been subject to the regulations of such markets, we may incur additional expenses, which may be material, to learn such regulations and ensure that we are operating in compliance with such regulations.

We are required to obtain, and to comply with, government permits and approvals.

We are required to obtain, and to comply with, numerous permits and licenses from federal, state and local governmental agencies. The process of obtaining and renewing necessary permits and licenses can be lengthy and complex and can sometimes result in the establishment of conditions that make the project or activity for which the permit or license was sought unprofitable or otherwise unattractive. In addition, such permits or licenses may be subject to denial, revocation or modification under various circumstances. Failure to obtain or comply with the conditions of permits or licenses, or failure to comply with applicable laws or regulations, may result in the delay or temporary suspension of our operations and electricity sales or the curtailment of our delivery of electricity to our customers and may subject us to penalties and other sanctions. Although various regulators routinely renew existing permits and licenses, renewal of our existing permits or licenses could be denied or jeopardized by various factors, including (a) failure to provide adequate financial assurance for closure, (b) failure to comply with environmental, health and safety laws and regulations or permit conditions, (c) local community, political or other opposition and (d) executive, legislative or regulatory action.

Our inability to procure and comply with the permits and licenses required for our operations, or the cost to us of such procurement or compliance, could have a material adverse effect on us. In addition, new environmental legislation or regulations, if enacted, or changed interpretations of existing laws, may cause routine maintenance activities at our facilities to need to be changed to avoid violating applicable laws and regulations or elicit claims that historical routine maintenance activities at our facilities violated applicable laws and regulations. In addition to the possible imposition of fines in the case of any such violations, we may be required to undertake significant capital investments in emissions control technology and obtain additional operating permits or licenses, which could have a material adverse effect on us.

Our cost of compliance with existing and new environmental laws could have a material adverse effect on us.

We are subject to extensive environmental regulation by governmental authorities, including the EPA and state environmental agencies and/or attorneys general. We may incur significant additional costs beyond those currently contemplated to comply with these regulatory requirements. If we fail to comply with these regulatory requirements, we could be subject to administrative, civil or criminal liabilities and fines. Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions, all of which could result in significant additional costs beyond those currently contemplated to comply with existing requirements. Any of the foregoing could have a material adverse effect on us.

The EPA has recently finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. In the future, the EPA may also propose and finalize additional regulatory actions that may adversely affect our existing generation facilities or our ability to cost-effectively develop new generation facilities. There is no assurance that the currently installed emissions control equipment at our lignite, coal and/or natural gas-fueled generation facilities will satisfy the requirements under any future EPA or state environmental regulations. Some of the recent regulatory actions and proposed actions, such as the EPA's Regional Haze Federal Implementation Plans (FIP) for reasonable progress and best available retrofit technology (BART), could require us to install significant additional control equipment, resulting in potentially material costs of compliance for our generation units, including capital expenditures, higher operating and fuel costs and potential production curtailments if the rules take effect as proposed or finalized. These costs could have a material adverse effect on us.

We may not be able to obtain or maintain all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain, maintain or comply with any such approval or if an approval is retroactively disallowed or adversely modified, the operation of our generation facilities could be stopped, disrupted, curtailed or modified or become subject to additional costs. Any such stoppage, disruption, curtailment, modification or additional costs could have a material adverse effect on us.

In addition, we may be responsible for any on-site liabilities associated with the environmental condition of facilities that we have acquired, leased or developed, regardless of when the liabilities arose and whether they are now known or unknown. In connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Another party could, depending on the circumstances, assert an environmental claim against us or fail to meet its indemnification obligations to us.

We could be materially and adversely affected if current regulations are implemented or if new federal or state legislation or regulations are adopted to address global climate change, or if we are subject to lawsuits for alleged damage to persons or property resulting from greenhouse gas emissions.

There is a concern nationally and internationally about global climate change and how GHG emissions, such as CO_2, contribute to global climate change. Over the last several years, the U.S. Congress has considered and debated, and President Obama's administration previously discussed, several proposals intended to address climate change using different approaches, including a cap on carbon emissions with emitters allowed to trade unused emission allowances (cap-and-trade), a tax on carbon or GHG emissions, incentives for the development of low-carbon technology and federal renewable portfolio standards. In October 2015, the EPA finalized regulations under the CAA to limit CO_2 emissions from existing generating units, referred to as the Clean Power Plan. If implemented as finalized, the Clean Power Plan would require the closure of a significant number of coal-fueled electricity generation units nationwide and in Texas. The Clean Power Plan is currently stayed pending the conclusion of legal challenges on the rule. In October 2017, the EPA proposed the repeal of the Clean Power Plan. In addition, a number of federal court cases have been filed in recent years asserting damage claims related to GHG emissions, and the results in those proceedings could establish adverse precedent that might apply to companies (including us) that produce GHG emissions. We could be materially and adversely affected if new federal and/or state legislation or regulations are adopted to address global climate change, if the Clean Power Plan is implemented as finalized or if we are subject to lawsuits for alleged damage to persons or property resulting from GHG emissions.

The integration of the Capacity Performance product into the PJM market and the Pay-for-Performance mechanism in ISO-NE could lead to substantial changes in capacity income and non-performance penalties, which could have a material adverse effect on our results of operations, financial condition and cash flows.

Both ISO-NE and PJM operate a pay-for-performance model where capacity payments are modified based on real-time generator performance. Capacity market prices are sensitive to design parameters, as well as additions of new capacity. We may experience substantial changes in capacity income and non-performance penalties, which could have a material adverse effect on our results of operations, financial condition and cash flows.

The availability and cost of emission allowances could adversely impact our costs of operations.

We are required to maintain, through either allocations or purchases, sufficient emission allowances for SO_2, CO_2 and NO_X to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet the obligations imposed on us by various applicable environmental laws. If our operational needs require more than our allocated allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances or install costly new emission controls. As we use the emission allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, the purchase of such allowances could materially increase our costs of operations in the affected markets.

Luminant's mining operations are subject to RCT oversight.

We currently own and operate, or are in the process of reclamation, 12 surface lignite coal mines in Texas to provide fuel for our electricity generation facilities. We also own or lease, and are in the process of reclaiming, two waste-to-energy surface facilities in Pennsylvania. The RCT, which exercises broad authority to regulate reclamation activity, reviews on an ongoing basis whether Luminant is compliant with RCT rules and regulations and whether it has met all the requirements of its mining permits. Any new rules and regulations adopted by the RCT or the Department of Interior Office of Surface Mining, which also regulates mining activity nationwide, or any changes in the interpretation of existing rules and regulations, could result in higher compliance costs or otherwise adversely affect our financial condition or cause a revocation of a mining permit. Any revocation of a mining permit would mean that Luminant would no longer be allowed to mine lignite at the applicable mine to serve its generation facilities. In addition, Luminant's mining reclamation obligations are secured by a first lien on its assets which is pari passu with the Vistra Operations Credit Facilities, but which would be paid first, up to $975 million, upon any liquidation of Vistra Operations' assets. The RCT could, at any time, require that Luminant's mining reclamation obligations be secured by cash or letters of credit in lieu of such first lien. Any failure to provide any such cash or letter of credit collateral could result in Luminant no longer being able to mine lignite. Any such event could have a material adverse effect on us.

Luminant's lignite mining reclamation activity will require significant resources as existing and retired mining operations are reclaimed over the next several years.

In conjunction with Luminant's announcements in the third and fourth quarters of 2017 to retire several power generation assets and related mining operations, along with the continuous reclamation activity at its continuing mining operations for its mines related to the Oak Grove and Martin Lake generation assets, Luminant is expected to spend a significant amount of money, internal resources and time to complete the required reclamation activities. For the next five years, Vistra Energy is projected to spend approximately $340 million (on a nominal basis) to achieve its reclamation objectives.

Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputation damage that could have a material adverse effect on us.

We are involved in the ordinary course of business in a number of lawsuits involving, among other matters, employment, commercial, and environmental issues, and other claims for injuries and damages. We evaluate litigation claims and legal proceedings to assess the likelihood of unfavorable outcomes and to estimate, if possible, the amount of potential losses. Based on these evaluations and estimates, when required by applicable accounting rules, we establish reserves and disclose the relevant litigation claims or legal proceedings, as appropriate. These evaluations and estimates are based on the information available to management at the time and involve a significant amount of judgment. Actual outcomes or losses may differ materially from current evaluations and estimates. The settlement or resolution of such claims or proceedings may have a material adverse effect on us. We use appropriate means to contest litigation threatened or filed against us, but the litigation environment poses a significant business risk.

We are also involved in the ordinary course of business in regulatory investigations and other administrative proceedings, and we are exposed to the risk that we may become the subject of additional regulatory investigations or administrative proceedings. While we cannot predict the outcome of any regulatory investigation or administrative proceeding, any such regulatory investigation or administrative proceeding could result in us incurring material penalties and/or other costs and have a materially adverse effect on us.

Our retail businesses, which each have REP certifications that are subject to review of the public utility commissions in the states in which we operate, are subject to changing state rules and regulations that could have a material impact on the profitability of our business.

The competitiveness of our retail businesses partially depends on state regulatory policies that establish the structure, rules, terms and conditions on which services are offered to retail customers. Specifically, the public utility commissions and/or the attorney generals of the various jurisdictions in which the Retail segment operates may at any time initiate an investigation into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements. These state policies and investigations, which can include controls on the retail rates our retail businesses can charge, the imposition of additional costs on sales, restrictions on our ability to obtain new customers through various marketing channels and disclosure requirements, investigations into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements, can affect the competitiveness of our retail businesses. Any removal or revocation of a REP certification would mean that we would no longer be allowed to provide electricity service to retail customers in the applicable jurisdiction, and such decertification could have a material adverse effect on us. Additionally, state or federal imposition of net metering or renewable portfolio standard programs can make it more or less expensive for retail customers to supplement or replace their reliance on grid power. Our retail businesses have limited ability to influence development of these state rules, regulations and policies, and our business model may be more or less effective, depending on changes to the regulatory environment.

Operational Risks

Volatile power supply costs and demand for power could adversely affect the financial performance of our retail businesses.

Although we are the primary provider of our retail businesses' wholesale electricity supply requirements, our retail businesses purchase a significant portion of their supply requirements from third parties. As a result, the financial performance of our retail business depends on their ability to obtain adequate supplies of electric generation from third parties at prices below the prices they charge their customers. Consequently, our earnings and cash flows could be adversely affected in any period in which the retail businesses' wholesale electricity supply costs rise at a greater rate than the rates they charge to customers. The price of wholesale electricity supply purchases associated with the retail businesses' energy commitments can be different than that reflected in the rates charged to customers due to, among other factors:

- varying supply procurement contracts used and the timing of entering into related contracts;
- subsequent changes in the overall price of natural gas;
- daily, monthly or seasonal fluctuations in the price of natural gas relative to the 12-month forward prices;
- transmission constraints and the Company's ability to move power to our customers, and
- changes in market heat rate.

The retail businesses' earnings and cash flows could also be adversely affected in any period in which their customers' actual usage of electricity significantly varies from the forecasted usage, which could occur due to, among other factors, weather events, competition and economic conditions.

Our retail operations are subject to significant competition from other REPs, which could result in a loss of existing customers and the inability to attract new customers.

We operate in a very competitive retail market and, as a result, our retail operation faces significant competition for customers. We believe our TXU Energy™, Homefield Energy and Dynegy Energy Services brands are viewed favorably in the retail electricity markets in which we operate, but despite our commitment to providing superior customer service and innovative products, customer sentiment toward our brands, including by comparison to our competitors' brands, depends on certain factors beyond our control. For example, competitor REPs may offer different products, lower electricity prices and other incentives, which, despite our long-standing relationship with many customers, may attract customers away from us. If we are unable to successfully compete with competitors in the retail market it is possible our retail customer counts could decline, which could have a material adverse effect on us.

As we try to grow our retail business and operate our business strategy, we compete with various other REPs that may have certain advantages over us. For example, in new markets, our principal competitor for new customers may be the incumbent REP, which has the advantage of long-standing relationships with its customers, including well-known brand recognition. In addition to competition from the incumbent REP, we may face competition from a number of other energy service providers, other energy industry participants, or nationally branded providers of consumer products and services who may develop businesses that will compete with us. Some of these competitors or potential competitors may be larger than we are or have greater resources or access to capital than we have. If there is inadequate potential margin in retail electricity markets with substantial competition to overcome the adverse effect of relatively high customer acquisition costs in such markets, it may not be profitable for us to compete in these markets.

Our retail operations rely on the infrastructure of local utilities or independent transmission system operators to provide electricity to, and to obtain information about, our customers. Any infrastructure failure could negatively impact customer satisfaction and could have a material adverse effect on us.

With the exception of Electric Energy, Inc. (EEI), which we acquired in the Merger and which owns and controls transmission lines interconnecting our Joppa facility in EEI's control to MISO, Tennessee Valley Authority and Louisville Gas and Electric Company, our retail operations depend on transmission and distribution facilities owned and operated by unaffiliated utilities to deliver the electricity that we sell to our customers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered and we may have to forgo sales or buy more expensive wholesale electricity than is available in the capacity-constrained area, or, with respect to capacity performance in PJM and performance incentives in ISO-NE, we may be subject to significant penalties. For example, during some periods, transmission access is constrained in some areas of the Dallas-Fort Worth metroplex, where we have a significant number of customers. The cost to provide service to these customers may exceed the cost to provide service to other customers, resulting in lower operating margins. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact customer satisfaction with our service. Any of the foregoing could have a material adverse effect on us.

The operation of our businesses is subject to cyber-based security and integrity risk. Attacks on our infrastructure that breach cyber/data security measures could expose us to significant liabilities and reputation damage and disrupt business operations, which could have a material adverse effect on us.

Numerous functions affecting the efficient operation of our businesses are dependent on the secure and reliable storage, processing and communication of electronic data and the use of sophisticated computer hardware and software systems and much of our information technology infrastructure is connected (directly or indirectly) to the internet. There have been numerous attacks on government and industry information technology systems through the internet that have resulted in material operational, reputation and/or financial costs. While we have controls in place designed to protect our infrastructure and we are not aware of any significant breaches in the past, a breach of cyber/data security measures that impairs our information technology infrastructure could disrupt normal business operations and affect our ability to control our generation assets, access retail customer information and limit communication with third parties. Any loss of confidential or proprietary data through a breach could adversely affect our reputation, expose us to material legal or regulatory claims and impair our ability to execute our business strategy, which could have a material adverse effect on us. In addition, we may experience increased capital and operating costs to implement increased security for our information technology infrastructure and plants.

As part of the continuing development of new and modified reliability standards, the FERC has approved changes to its Critical Infrastructure Protection reliability standards and has established standards for assets identified as "critical cyber assets." Under the Energy Policy Act of 2005, the FERC can impose penalties (up to $1 million per day, per violation) for failure to comply with mandatory electric reliability standards, including standards to protect the power system against potential disruptions from cyber/data and physical security breaches.

Further, our retail business requires access to sensitive customer data in the ordinary course of business. Examples of sensitive customer data are names, addresses, account information, historical electricity usage, expected patterns of use, payment history, credit bureau data, credit and debit card account numbers, drivers' license numbers, social security numbers and bank account information. Our retail business may need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center operations, to the retail business. If a significant breach were to occur, the reputation of our retail business may be adversely affected, customer confidence may be diminished, and our retail business may be subject to substantial legal or regulatory claims, any of which may contribute to the loss of customers and have a material adverse effect on us.

We may suffer material losses, costs and liabilities due to ownership and operation of the Comanche Peak nuclear generation facility.

We own and operate a nuclear generation facility in Glen Rose, Texas (Comanche Peak Facility). The ownership and operation of a nuclear generation facility involves certain risks. These risks include:

- unscheduled outages or unexpected costs due to equipment, mechanical, structural, cybersecurity or other problems;
- inadequacy or lapses in maintenance protocols;
- the impairment of reactor operation and safety systems due to human error or force majeure;
- the costs of, and liabilities relating to, storage, handling, treatment, transport, release, use and disposal of radioactive materials;
- the costs of procuring nuclear fuel;

- the costs of storing and maintaining spent nuclear fuel at our on-site dry cask storage facility;
- terrorist or cybersecurity attacks and the cost to protect against any such attack;
- the impact of a natural disaster;
- limitations on the amounts and types of insurance coverage commercially available, and
- uncertainties with respect to the technological and financial aspects of modifying or decommissioning nuclear facilities at the end of their useful lives.

Any prolonged unavailability of the Comanche Peak Facility could have a material adverse effect on our results of operation, cash flows, financial position and reputation. The following are among the more significant related risks:

- *Operational Risk* — Operations at any generation facility could degrade to the point where the facility would have to be shut down. If such degradations were to occur at the Comanche Peak Facility, the process of identifying and correcting the causes of the operational downgrade to return the facility to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet supply commitments. Furthermore, a shut-down or failure at any other nuclear generation facility could cause regulators to require a shut-down or reduced availability at the Comanche Peak Facility.
- *Regulatory Risk* — The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under it or the terms of the licenses of nuclear generation facilities. Unless extended, as to which no assurance can be given, the NRC operating licenses for the two licensed operating units at the Comanche Peak Facility will expire in 2030 and 2033, respectively. Changes in regulations by the NRC, as well as any extension of our operating licenses, could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.
- *Nuclear Accident Risk* — Although the safety record of the Comanche Peak Facility and other nuclear generation facilities generally has been very good, accidents and other unforeseen problems have occurred both in the U.S. and elsewhere. The consequences of an accident can be severe and include loss of life, injury, lasting negative health impacts and property damage. Any accident, or perceived accident, could result in significant liabilities and damage our reputation. Any such resulting liability from a nuclear accident could exceed our resources, including insurance coverage, and could ultimately result in the suspension or termination of power generation from the Comanche Peak Facility.

The operation and maintenance of power generation facilities and related mining operations involve significant risks that could adversely affect our results of operations, liquidity and financial condition.

The operation and maintenance of power generation facilities and related mining operations involve many risks, including, as applicable, start-up risks, breakdown or failure of facilities, equipment or processes, operator error, lack of sufficient capital to maintain the facilities, the dependence on a specific fuel source, the inability to transport our product to our customers in an efficient manner due to the lack of transmission capacity or the impact of unusual or adverse weather conditions or other natural events, or terrorist attacks, as well as the risk of performance below expected levels of output, efficiency or reliability, the occurrence of any of which could result in substantial lost revenues and/or increased expenses. A significant number of our facilities were constructed many years ago. Older generating equipment, even if maintained or refurbished in accordance with good engineering practices, may require significant capital expenditures to operate at peak efficiency or reliability. The risk of increased maintenance and capital expenditures arises from (a) increased starting and stopping of generation equipment due to the volatility of the competitive generation market and the prospect of continuing low wholesale electricity prices that may not justify sustained or year-round operation of all our generation facilities, (b) any unexpected failure to generate power, including failure caused by equipment breakdown or unplanned outage (whether by order of applicable governmental regulatory authorities, the impact of weather events or natural disasters or otherwise), (c) damage to facilities due to storms, natural disasters, wars, terrorist or cyber/data security acts and other catastrophic events and (d) the passage of time and normal wear and tear. Further, our ability to successfully and timely complete routine maintenance or other capital projects at our existing facilities is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs or losses and write downs of our investment in the project.

We cannot be certain of the level of capital expenditures that will be required due to changing environmental and safety laws and regulations (including changes in the interpretation or enforcement thereof), needed facility repairs and unexpected events (such as natural disasters or terrorist or cyber/data security attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on us. Moreover, if we significantly modify a unit, we may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under the new source review provisions of the CAA, which would likely result in substantial additional capital expenditures.

In addition, unplanned outages at any of our generation facilities, whether because of equipment breakdown or otherwise, typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWh or non-performance penalties or require us to incur significant costs as a result of running one of our higher cost units or to procure replacement power at spot market prices in order to fulfill contractual commitments. If we do not have adequate liquidity to meet margin and collateral requirements, we may be exposed to significant losses, may miss significant opportunities and may have increased exposure to the volatility of spot markets, which could have a material adverse effect on us. Further, our inability to operate our generation facilities efficiently, manage capital expenditures and costs, and generate earnings and cash flow from our asset-based businesses could have a material adverse effect on our results of operations, financial condition or cash flows. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover our lost revenues, increased expenses or liquidated damages payments should we experience equipment breakdown or non-performance by contractors or vendors.

Operation of power generation facilities involves significant risks and hazards customary to the power industry that could have a material adverse effect on Vistra Energy's revenues and results of operations, and Vistra Energy may not have adequate insurance to cover these risks and hazards. Our employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of our operations.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of equipment and delivering electricity to transmission and distribution systems. In addition to natural risks such as earthquake, flood, lightning, hurricane and wind, other hazards, such as nuclear accidents, dam failure, gas or other explosions, mine area collapses, fire, structural collapse, machinery failure and other dangerous incidents are inherent risks in our operations. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. Further, our employees and contractors work in, and customers and the general public may be exposed to, potentially dangerous environments at or near our operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life.

The occurrence of any one of these events may result in us being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot provide any assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject and, even if we do have insurance coverage for a particular circumstance, we may be subject to a large deductible and maximum cap. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, we cannot provide any assurance that our insurance coverage will continue to be available at all or at rates or on terms similar to those presently available. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows.

We may be materially and adversely affected by the effects of extreme weather conditions and seasonality.

We may be materially affected by weather conditions and our businesses may fluctuate substantially on a seasonal basis as the weather changes. In addition, we could be subject to the effects of extreme weather conditions, including sustained cold or hot temperatures, hurricanes, storms or other natural disasters, which could stress our generation facilities and result in outages, destroy our assets and result in casualty losses that are not ultimately offset by insurance proceeds, and could require increased capital expenditures or maintenance costs, including supply chain costs.

Moreover, an extreme weather event could cause disruption in service to customers due to downed wires and poles or damage to other operating equipment, which could result in us foregoing sales of electricity and lost revenue. Similarly, an extreme weather event might affect the availability of generation and transmission capacity, limiting our ability to source or deliver power where it is needed or limit our ability to source fuel for our plants (including due to damage to rail or natural gas pipeline infrastructure). Additionally, extreme weather may result in unexpected increases in customer load, requiring our retail operation to procure additional electricity supplies at wholesale prices in excess of customer sales prices for electricity. These conditions, which cannot be reliably predicted, could have adverse consequences by requiring us to seek additional sources of electricity when wholesale market prices are high or to sell excess electricity when market prices are low, which could have a material adverse effect on us.

Changes in technology or increased electricity conservation efforts may reduce the value of our generation facilities and may otherwise have a material adverse effect on us.

Technological advances have improved, and are likely to continue to improve, for existing and alternative methods to produce and store power, including gas turbines, wind turbines, fuel cells, micro turbines, photovoltaic (solar) cells, batteries and concentrated solar thermal devices, along with improvements in traditional technologies. Such technological advances have reduced, and are expected to continue to reduce, the costs of power production or storage to a level that will enable these technologies to compete effectively with traditional generation facilities. Consequently, the value of our more traditional generation assets could be significantly reduced as a result of these competitive advances, which could have a material adverse effect on us. In addition, changes in technology have altered, and are expected to continue to alter, the channels through which retail customers buy electricity (*i.e.*, self-generation or distributed-generation facilities). To the extent self-generation facilities become a more cost-effective option for customers, our financial condition, operating cash flows and results of operations could be materially and adversely affected.

Technological advances in demand-side management and increased conservation efforts have resulted, and are expected to continue to result, in a decrease in electricity demand. A significant decrease in electricity demand as a result of such efforts would significantly reduce the value of our generation assets. Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce power consumption. Effective power conservation by our customers could result in reduced electricity demand or significantly slow the growth in such demand. Any such reduction in demand could have a material adverse effect on us. Furthermore, we may incur increased capital expenditures if we are required to increase investment in conservation measures.

The loss of the services of our key management and personnel could adversely affect our ability to successfully operate our businesses.

Our future success will depend on our ability to continue to attract and retain highly qualified personnel. We compete for such personnel with many other companies, in and outside of our industry, government entities and other organizations. We may not be successful in retaining current personnel or in hiring or retaining qualified personnel in the future. Our failure to attract highly qualified new personnel or retain highly qualified existing personnel could have an adverse effect on our ability to successfully operate our businesses.

We could be materially and adversely impacted by strikes or work stoppages by our unionized employees.

As of December 31, 2018, we had approximately 2,030 employees covered by collective bargaining agreements, of which approximately 945 are subject to collective bargaining agreements entered into by Dynegy and assumed by us in the Merger. The terms of all collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal- and nuclear-fueled generation operation and some of our natural gas-fueled generation operations expire on various dates between March 2019 and March 2022, but remain effective from-year-to-year thereafter unless and until terminated by either party. In the event that our union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we would be responsible for procuring replacement labor or we could experience reduced power generation or outages. Our ability to procure such labor is uncertain. Strikes, work stoppages or the inability to negotiate current or future collective bargaining agreements on favorable terms or at all could have a material adverse effect on us.

Risks Related to Our Structure and Ownership of our Common Stock

Vistra Energy is a holding company and its ability to obtain funds from its subsidiaries is structurally subordinated to existing and future liabilities and preferred equity of its subsidiaries.

Vistra Energy is a holding company that does not conduct any business operations of its own. As a result, Vistra Energy's cash flows and ability to meet its obligations are largely dependent upon the operating cash flows of Vistra Energy's subsidiaries and the payment of such operating cash flows to Vistra Energy in the form of dividends, distributions, loans or otherwise. These subsidiaries are separate and distinct legal entities from Vistra Energy and have no obligation (other than any existing contractual obligations) to provide Vistra Energy with funds to satisfy its obligations. Any decision by a subsidiary to provide Vistra Energy with funds to satisfy its obligations, including those under the TRA, whether by dividends, distributions, loans or otherwise, will depend on, among other things, such subsidiary's results of operations, financial condition, cash flows, cash requirements, contractual prohibitions and other restrictions, applicable law and other factors. The deterioration of income from, or other available assets of, any such subsidiary for any reason could limit or impair its ability to pay dividends or make other distributions to Vistra Energy.

We may not pay any dividends on our common stock in the future.

In November 2018, we announced that the Board had adopted a dividend program pursuant to which we expect to initiate an annual dividend of approximately $0.50 per share, payable quarterly, beginning in the first quarter of 2019. Each dividend under the program will be subject to declaration by the Board and, thus, may be subject to numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, our results of operations, financial condition and liquidity, contractual prohibitions and other restrictions with respect to the payment of dividends. There is no assurance that the Board will declare, or that we will pay, any dividends on our common stock in the future.

A small number of stockholders could be able to significantly influence or impact our business and affairs.

Three of the largest groups of stockholders of Vistra Energy, affiliates of Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P. (collectively, the Brookfield Entities), affiliates of Oaktree Capital Management, L.P. (collectively, the Oaktree Entities), and affiliates of Apollo Management Holdings L.P. (collectively, the Apollo Entities, and together with the Brookfield Entities and the Oaktree Entities, the Principal Stockholders), all of which were first lien creditors of our Predecessor prior to Emergence, currently collectively own approximately 26% of our common stock outstanding. Large holders such as the Principal Stockholders may be able to affect matters requiring approval by holders of our common stock, including the election of directors and the approval of any strategic transactions. Furthermore, pursuant to the terms of stockholders' agreements entered into with each of the Brookfield Entities and the Apollo Entities, each such Principal Stockholder is entitled to designate one director to serve on the Board as a Class III director for so long as it beneficially owns, in the aggregate, at least 22,500,000 shares of our common stock.

Additionally, we may be subject, from time to time, to legal and business challenges in the operation of our company due to actions instituted by activist shareholders or others. Responding to such actions, which may include private engagement, publicity campaigns, proxy contests, efforts to force transactions not supported by our Board, and litigation, could be costly and time-consuming, may not align with our strategic plan and could divert the time and attention of our Board and management from our business.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. PROPERTIES

Luminant's generation fleet consists of power generation units in six RTOs/ISOs, with the location, RTO/ISO, technology, primary fuel type, net capacity and ownership interest for each generation facility shown in the table below:

Facility	Location	RTO/ISO	Technology	Primary Fuel	Net Capacity (MW) (a)	Ownership Interest
Ennis	Ennis, TX	ERCOT	CCGT	Natural Gas	366	100%
Forney	Forney, TX	ERCOT	CCGT	Natural Gas	1,912	100%
Hays	San Marcos, TX	ERCOT	CCGT	Natural Gas	1,047	100%
Lamar	Paris, TX	ERCOT	CCGT	Natural Gas	1,076	100%
Midlothian	Midlothian, TX	ERCOT	CCGT	Natural Gas	1,596	100%
Odessa	Odessa, TX	ERCOT	CCGT	Natural Gas	1,054	100%
Wise	Poolville, TX	ERCOT	CCGT	Natural Gas	787	100%
Coleto Creek	Goliad, TX	ERCOT	ST	Coal	650	100%
Martin Lake	Tatum, TX	ERCOT	ST	Coal	2,250	100%
Oak Grove	Franklin, TX	ERCOT	ST	Coal	1,600	100%
DeCordova	Granbury, TX	ERCOT	CT	Natural Gas	260	100%
Graham	Graham, TX	ERCOT	ST	Natural Gas	630	100%
Lake Hubbard	Dallas, TX	ERCOT	ST	Natural Gas	921	100%
Morgan Creek	Colorado City, TX	ERCOT	CT	Natural Gas	390	100%
Permian Basin	Monahans, TX	ERCOT	CT	Natural Gas	325	100%
Stryker Creek	Rusk, TX	ERCOT	ST	Natural Gas	685	100%
Trinidad	Trinidad, TX	ERCOT	ST	Natural Gas	244	100%
Wharton	Boling, TX	ERCOT	CT	Natural Gas	83	100%
Comanche Peak	Glen Rose, TX	ERCOT	Nuclear	Nuclear	2,300	100%
Upton 2	Upton County, TX	ERCOT	Solar	Solar	180	100%
Upton 2 Battery Storage	Upton County, TX	ERCOT	Battery	Battery	10	100%
Total ERCOT Segment					18,366	
Fayette	Masontown, PA	PJM	CCGT	Natural Gas	726	100%
Hanging Rock	Ironton, OH	PJM	CCGT	Natural Gas	1,430	100%
Hopewell	Hopewell, VA	PJM	CCGT	Natural Gas	370	100%
Kendall	Minooka, IL	PJM	CCGT	Natural Gas	1,288	100%
Liberty	Eddystone, PA	PJM	CCGT	Natural Gas	607	100%
Ontelaunee	Reading, PA	PJM	CCGT	Natural Gas	600	100%
Sayreville	Sayreville, NJ	PJM	CCGT	Natural Gas	170	50%
Washington	Beverly, OH	PJM	CCGT	Natural Gas	711	100%
Kincaid	Kincaid, IL	PJM	ST	Coal	1,108	100%
Miami Fort 7 & 8	North Bend, OH	PJM	ST	Coal	1,020	100%
Zimmer	Moscow, OH	PJM	ST	Coal	1,300	100%
Calumet	Chicago, IL	PJM	CT	Natural Gas	380	100%
Dicks Creek	Monroe, OH	PJM	CT	Natural Gas	155	100%
Miami Fort (CT)	North Bend, OH	PJM	CT	Oil	77	100%
Pleasants	Saint Marys, WV	PJM	CT	Natural Gas	388	100%
Richland	Defiance, OH	PJM	CT	Natural Gas	423	100%
Stryker	Stryker, OH	PJM	CT	Oil	16	100%
Total PJM Segment					10,769	

Facility	Location	RTO/ISO	Technology	Primary Fuel	Net Capacity (MW) (a)	Ownership Interest
Bellingham	Bellingham, MA	ISO-NE	CCGT	Natural Gas	566	100%
Bellingham NEA	Bellingham, MA	ISO-NE	CCGT	Natural Gas	157	50%
Blackstone	Blackstone, MA	ISO-NE	CCGT	Natural Gas	544	100%
Casco Bay	Veazie, ME	ISO-NE	CCGT	Natural Gas	543	100%
Independence	Oswego, NY	NYISO	CCGT	Natural Gas	1,212	100%
Lake Road	Dayville, CT	ISO-NE	CCGT	Natural Gas	827	100%
MASSPOWER	Indian Orchard, MA	ISO-NE	CCGT	Natural Gas	281	100%
Milford	Milford, CT	ISO-NE	CCGT	Natural Gas	600	100%
Total NY/NE Segment					4,730	
Baldwin	Baldwin, IL	MISO	ST	Coal	1,185	100%
Havana	Havana, IL	MISO	ST	Coal	434	100%
Hennepin	Hennepin, IL	MISO	ST	Coal	294	100%
Coffeen	Coffeen, IL	MISO/PJM	ST	Coal	915	100%
Duck Creek	Canton, IL	MISO/PJM	ST	Coal	425	100%
Edwards	Bartonville, IL	MISO/PJM	ST	Coal	585	100%
Newton	Newton, IL	MISO/PJM	ST	Coal	615	100%
Joppa/EEI	Joppa, IL	MISO	ST	Coal	802	80%
Joppa CT 1-3	Joppa, IL	MISO	CT	Natural Gas	165	100%
Joppa CT 4-5	Joppa, IL	MISO	CT	Natural Gas	56	80%
Total MISO Segment					5,476	
Moss Landing 1 & 2	Moss Landing, CA	CAISO	CCGT	Natural Gas	1,020	100%
Oakland	Oakland, CA	CAISO	CT	Oil	165	100%
Total CAISO					1,185	
Total capacity					40,526	

(a) Unit capabilities are based on winter capacity and are reflected at our net ownership interest. We have not included units that have been retired or are out of operation.

Our wholesale commodity risk management group also procures renewable energy credits from wind generation in ERCOT to support our electricity sales to wholesale and retail customers to satisfy the increasing demand for renewable resources from such customers. As of December 31, 2018, Vistra Energy had long-term power purchase agreements to procure approximately 480 MW of available renewable capacity. These renewable generation sources deliver electricity when conditions make them available, and, when on-line, they generally compete with baseload units. Because they cannot be relied upon to meet demand continuously due to their dependence on weather and time of day, these generation sources are categorized as non-dispatchable and create the need for intermediate/load-following resources to respond to changes in their output.

Fuel Supply

Nuclear — We operate two nuclear generation units at the Comanche Peak plant site in ERCOT, each of which is designed for a capacity of 1,150 MW. Comanche Peak Unit 1 and Unit 2 went into commercial operation in 1990 and 1993, respectively, and are generally operated at full capacity. Refueling (nuclear fuel assembly replacement) outages for each unit are scheduled to occur every eighteen months during the spring or fall off-peak demand periods. Every three years, the refueling cycle results in the refueling of both units during the same year, the latest of which occurred during 2017. While one unit is undergoing a refueling outage, the remaining unit is intended to operate at full capacity. During a refueling outage, other maintenance, modification and testing activities are completed that cannot be accomplished when the unit is in operation. The Comanche Peak facility operated at a capacity factor of 101%, 84% and 101% in 2018, 2017 and 2016, respectively. The capacity factor for the year ended December 31, 2017 reflected an unplanned outage at one of the units between June and August 2017.

We have contracts in place for our 2019 and 2020 nuclear fuel requirements. We do not anticipate any significant difficulties in acquiring uranium and contracting for associated conversion, enrichment and fabrication services in the foreseeable future.

Coal/Lignite — Our coal/lignite-fueled generation fleet is comprised of 14 generation facilities totaling 13,183 MW of generation capacity. Maintenance outages at these units are scheduled during the spring or fall off-peak demand periods. We meet our fuel requirements at our coal-fueled generation facilities in PJM and MISO with coal purchased from multiple suppliers under contracts of various lengths and transported to the facilities by either railcar or barges. We meet our fuel requirements in ERCOT using lignite that we mine at the Oak Grove generation facility, coal purchased and transported by railcar at the Coleto Creek generation facility and a blend of lignite that we mine and coal purchased and transported by railcar at our Martin Lake generation facility.

Natural Gas — Our natural gas-fueled generation fleet is comprised of 24 CCGT generating facilities totaling 19,490 MW and 14 peaking generation facilities totaling 5,105 MW. We satisfy our fuel requirements at these facilities through a combination of spot market and near-term purchase contracts. Additionally, we have near-term natural gas transportation agreements in place to ensure reliable fuel supply.

Item 3. LEGAL PROCEEDINGS

See Note 15 to the Financial Statements for discussion of litigation, including matters related to our generation facilities and EPA reviews.

Item 4. MINE SAFETY DISCLOSURES

Vistra Energy currently owns and operates, or is in the process of reclaiming, 12 surface lignite coal mines in Texas to provide fuel for its electricity generation facilities. Vistra Energy also owns or leases, and is in the process of reclaiming, two waste-to-energy surface facilities in Pennsylvania. These mining operations are regulated by the MSHA under the Federal Mine Safety and Health Act of 1977, as amended (the Mine Act), as well as other federal and state regulatory agencies such as the RCT and Office of Surface Mining. The MSHA inspects U.S. mines, including Vistra Energy's mines, on a regular basis, and if it believes a violation of the Mine Act or any health or safety standard or other regulation has occurred, it may issue a citation or order, generally accompanied by a proposed fine or assessment. Such citations and orders can be contested and appealed, which often results in a reduction of the severity and amount of fines and assessments and sometimes results in dismissal. Disclosure of MSHA citations, orders and proposed assessments are provided in Exhibit 95.1 to this Annual Report on Form 10-K.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Vistra Energy's authorized capital stock consists of 1,800,000,000 shares of common stock with a par value of $0.01 per share.

Since May 10, 2017, Vistra Energy's common stock has been listed on the NYSE under the symbol "VST". Upon Emergence and through May 9, 2017, Vistra Energy's common stock was listed on the OTCQX U.S. under the symbol "VSTE".

On April 9, 2018 (Merger Date), pursuant to the Merger Agreement, 94,409,573 shares of Vistra Energy common stock were issued to the former Dynegy stockholders, as well as converting stock options, equity-based awards, tangible equity units and warrants.

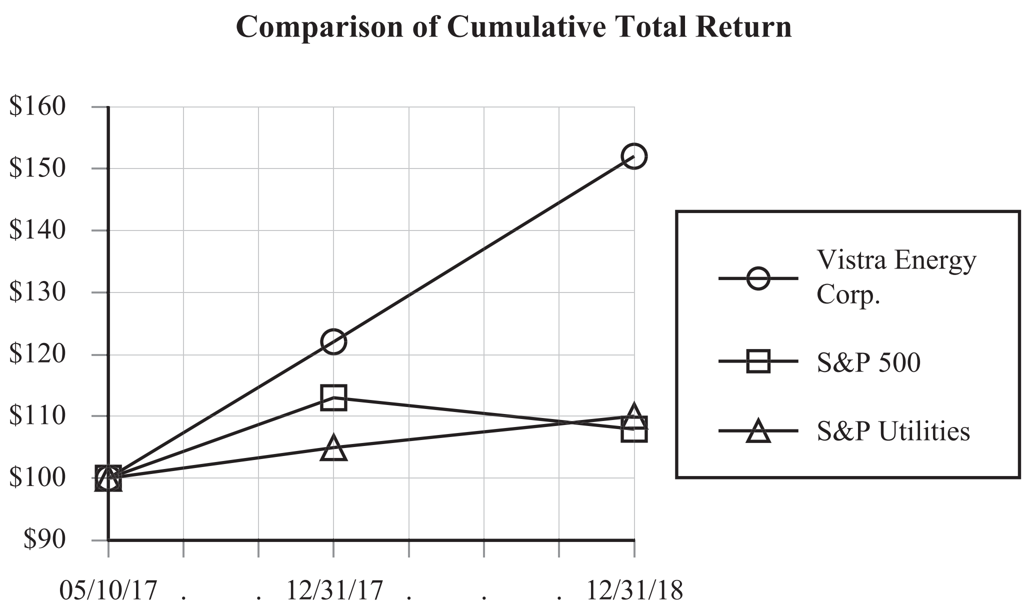
As of February 25, 2019, there were 485,894,408 shares of common stock issued and outstanding and 630 shareholders of record.

Vistra Energy paid a one-time dividend in the aggregate amount of approximately $1 billion ($2.32 per share of common stock) to holders of record of our common stock on December 19, 2016. In November 2018, we announced that the Board had adopted a dividend program pursuant to which we expect to initiate an annual dividend of approximately $0.50 per share, payable quarterly, beginning in the first quarter of 2019. Each dividend under the program will be subject to declaration by the Board and, thus, may be subject to numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, our results of operations, financial condition and liquidity and Delaware law. For additional details, see Item 1A. *Risk Factors* and Note 16 to the Financial Statements

Subject to limitations under applicable Delaware law, preferences that may apply to any outstanding shares of our preferred stock and contractual restrictions, holders of our common stock are entitled to receive dividends or other distributions ratably, when, as and if declared by the Board. The ability of the Board to declare dividends with respect to our common stock, however, will be subject to such limitations, preferences and restrictions and the availability of sufficient funds under the Delaware General Corporation Law (DGCL) to pay such dividends.

Stock Performance Graph

The performance graph below compares Vistra Energy's cumulative total return on common stock for the period from May 10, 2017 through December 31, 2018 with the cumulative total returns of the S&P 500 Stock Index (S&P 500) and the S&P Utility Index (S&P Utilities). The graph below compares the return in each period assuming that $100 was invested at May 10, 2017 in Vistra Energy's common stock, the S&P 500 and the S&P Utilities, and that all dividends were reinvested.



Share Repurchase Program

The following table provides information about our repurchase of equity securities that are registered by us pursuant to Section 12 of the Securities Exchange Act of 1934, as amended, during the quarter ended December 31, 2018.

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of a Publicly Announced Program	Maximum Dollar Amount of Shares that may yet be Purchased under the Program (in millions)
October 1 - October 31, 2018	3,150,820	$ 24.38	3,150,820	$ —
November 1 - November 30, 2018	6,238,950	$ 22.99	6,238,950	$ 1,107
December 1 - December 31, 2018	5,834,141	$ 22.99	5,834,141	$ 972
For the quarter ended December 31, 2018	15,223,911	$ 23.28	15,223,911	$ 972

In June 2018, we announced that the Board had authorized a share repurchase program under which up to $500 million of our outstanding common stock could be repurchased. This share repurchase program was effective as of June 13, 2018, and the program was completed on October 19, 2018.

In November 2018, we announced that the Board had authorized an incremental share repurchase program under which up to $1.25 billion of our outstanding stock may be purchased. We intend to implement the program opportunistically from time to time over approximately the next 12 months.

Shares of the Company's stock will be repurchased from time to time in open market transactions at prevailing market prices, in privately negotiated transactions, pursuant to plans complying with Rule 10b5-1 and 10b-18 under the Securities Exchange Act of 1934, as amended, or by other means in accordance with federal securities laws. The actual timing, number and value of shares repurchased under the share repurchase program will be determined at our discretion and will depend on a number of factors, including the market price of our stock, general market and economic conditions, applicable legal requirements and compliance with the terms of our debt agreements.

Item 6. SELECTED FINANCIAL DATA

VISTRA ENERGY CORP.
SELECTED CONSOLIDATED FINANCIAL INFORMATION
(Millions of Dollars, Except Per Share Amounts and Ratios

	Successor			Predecessor		
	Year Ended December 31, 2018 (a)	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Operating revenues	$ 9,144	$ 5,430	$ 1,191	$ 3,973	$ 5,370	$ 5,978
Impairment of goodwill	$ —	$ —	$ —	$ —	$ (2,200)	$ (1,600)
Impairment of long-lived assets	$ —	$ (25)	$ —	$ —	$ (2,541)	$ (4,670)
Operating income (loss)	$ 491	$ 198	$ (161)	$ 568	$ (4,091)	$ (6,015)
Net income (loss) attributable to Vistra Energy/the Predecessor (b)	$ (54)	$ (254)	$ (163)	$ 22,851	$ (4,677)	$ (6,229)
Cash provided by (used in) operating activities	$ 1,471	$ 1,386	$ 81	$ (238)	$ 237	$ 444
Net loss per weighted average share of common stock outstanding — basic	$ (0.11)	$ (0.59)	$ (0.38)			
Net loss per weighted average share of common stock outstanding — diluted	$ (0.11)	$ (0.59)	$ (0.38)			
Dividend declared per share of common stock	$ —	$ —	$ 2.32			

	Successor			Predecessor	
	At December 31,			At December 31,	
	2018	2017	2016	2015	2014
Balance Sheet Information:					
Total assets (c)(d)	$ 26,024	$ 14,600	$ 15,167	$ 15,658	$ 21,343
Property, plant and equipment — net (c)(d)	$ 14,612	$ 4,820	$ 4,443	$ 9,349	$ 12,288
Goodwill and intangible assets (e)	$ 4,561	$ 4,437	$ 5,112	$ 1,331	$ 3,688
Long-term debt including current maturities (e)	$ 11,065	$ 4,423	$ 4,623	$ 19	$ 73
Borrowings under debtor-in-possession credit facility	$ —	$ —	$ —	$ 1,425	$ 1,425
Pre-Petition notes, loans and other debt reported as liabilities subject to compromise (e)	$ —	$ —	$ —	$ 31,668	$ 31,856
Total stockholders' equity/membership interests	$ 7,863	$ 6,342	$ 6,597	$ (22,884)	$ (18,209)

(a) For the year ended December 31, 2018, reflects the results of operations acquired in the Merger.

(b) For the Predecessor period from January 1, 2016 through October 2, 2016, net income includes net gains totaling $22.121 billion related to bankruptcy-related reorganization items including gains on extinguishing claims pursuant to the Plan of Reorganization (see Notes 5 and 7 to the Financial Statements).

(c) At December 31, 2018, includes assets acquired in the Merger.

(d) Reflects the impacts of impairment charges related to long-lived assets of $2.541 billion and $4.670 billion in the years ended December 31, 2015 and 2014, respectively (see Note 4 to the Financial Statements).

(e) As of December 31, 2015 and 2014, includes both unsecured and under secured obligations incurred prior to the Petition Date, but excludes pre-petition obligations that were fully secured and other obligations that were allowed to be paid as ordered by the Bankruptcy Court. As of December 31, 2014, also excludes $702 million of deferred debt issuance and extension costs.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

As described in Note 1 to the Financial Statements, Vistra Energy is considered a new reporting entity for accounting purposes as of the Effective Date, and its financial statements reflect the application of fresh start reporting. The financial statements of Vistra Energy (the Successor) for periods subsequent to the Effective Date are not comparable to the financial statements of TCEH (the Predecessor) for periods prior to the Effective Date, as those previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities that resulted from the Plan of Reorganization, and the related application of fresh start reporting, which includes accounting policies implemented by Vistra Energy that may differ from the Predecessor. See Note 6 to the Financial Statements for further discussion of fresh start reporting.

The following discussion and analysis of our financial condition and results of operations for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 should be read in conjunction with our consolidated financial statements and the notes to those statements. Results are impacted by the effects of the Merger, fresh start reporting, the Bankruptcy Filing and the application of Financial Accounting Standards Board Accounting Standards Codification (ASC) 852, *Reorganizations.*

All dollar amounts in the tables in the following discussion and analysis are stated in millions of U.S. dollars unless otherwise indicated.

Business

Vistra Energy is a holding company operating an integrated power business in markets thorough the U.S. Through our subsidiaries, we are engaged in competitive electricity market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and related services to end users. Prior to the Effective Date, TCEH was a holding company for our subsidiaries, which were principally engaged in the same activities as they are today.

Operating Segments

Vistra Energy has six reportable segments: (i) Retail, (ii) ERCOT, (iii) PJM, (iv) NY/NE (comprising NYISO and ISO-NE), (v) MISO and (vi) Asset Closure. The PJM, NY/NE and MISO segments were established on the Merger Date to reflect markets served by businesses acquired in the Merger. Prior to the Effective Date, there were no reportable business segments for TCEH. See Note 22 to the Financial Statements for further information concerning reportable business segments.

Significant Activities and Events and Items Influencing Future Performance

Entry into Purchase Agreement to Acquire Crius Energy Trust

On February 7, 2019, Vistra Energy and Crius Energy Trust (Crius) entered into a definitive agreement, which was subsequently amended on February 19, 2019 (as amended, the Crius Purchase Agreement), as a result of an unsolicited acquisition proposal, pursuant to which Vistra Energy will acquire the equity interest of two wholly owned subsidiaries of Crius that indirectly own the operating business of Crius (Crius Transaction). Crius is an energy retailer selling both electricity and natural gas products to residential and small business customers in 19 states and the District of Columbia.

The acquisition provides a high degree of overlap with Vistra Energy's generation fleet with approximately 11.6 TWh of annual load, improving Vistra Energy's match of its generation to load profile to approximately 45 percent, reducing risk. The acquisition also establishes a platform for future growth by leveraging Vistra Energy's existing retail marketing capabilities and Crius's experienced team. The acquisition enhances the integrated value proposition through collateral and transaction efficiencies, particularly via Crius's largely retail portfolio.

Vistra Energy intends to fund the purchase price of approximately $378 million using cash on hand and assumption of Crius's net debt of approximately $108 million. Completion of the Crius Transaction is subject to various customary conditions, including, among others, (i) approval by at least two-thirds of the Crius unitholders and (ii) receipt of all requisite regulatory approvals, which include approvals of the FERC and the expiration and termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Pending the receipt of all necessary approvals and the fulfillment of all other customary closing conditions, the parties expect the transaction to close in the second quarter of 2019.

Merger Transaction

On the Merger Date, Vistra Energy and Dynegy completed the transactions contemplated by the Merger Agreement. Pursuant to the Merger Agreement, Dynegy merged with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation.

At the closing of the Merger, each issued and outstanding share of Dynegy common stock, par value $0.01 per share, other than shares owned by Vistra Energy or its subsidiaries, held in treasury by Dynegy or held by a subsidiary of Dynegy, was automatically converted into 0.652 shares of common stock, par value $0.01 per share, of Vistra Energy, except that cash was paid in lieu of fractional shares.

Based on the opening price of Vistra Energy common stock on the Merger Date, the purchase price was approximately $2.3 billion. The purchase price allocation is substantially complete, but is dependent upon final valuation determinations, which may materially change from our current estimates. The preliminary values for property plant and equipment, identifiable intangible assets and liabilities, goodwill, inventories, asset retirement obligations, contingent liabilities and deferred taxes represent our current best estimates of the fair value at the Merger Date. We currently expect the final purchase price allocation will be completed no later than the first quarter of 2019 and goodwill will be allocated to the related reporting units at that time.

See Note 2 to the Financial Statements for a summary of the Merger transaction and business combination accounting.

Acquisition, Development and Disposition of Generation Facilities

Battery Energy Storage Projects — We have completed the construction of our first battery energy storage system. In October 2018, we were awarded a $1 million grant from the TCEQ for our battery energy storage system at Upton 2 solar facility. The grant is part of the Texas Emissions Reduction Plan. The 10 MW lithium-ion energy storage system captures excess solar energy produced during the day and releases the energy in late afternoon and early evening, when demand is highest. The project became operational on December 31, 2018.

In June 2018, we announced that we would enter into a 20-year resource adequacy contract with Pacific Gas and Electric Company (PG&E) to develop a 300 MW battery energy storage project at our Moss Landing Power Plant site in California. PG&E filed its application with the California Public Utilities Commission (CPUC) in June 2018 and the CPUC approved the contract in November 2018. We anticipate the battery storage project will enter commercial operations by the fourth quarter of 2020.

Upton 2 Solar Development — In May 2017, we acquired the rights to develop, construct and operate a utility scale solar photovoltaic power generation facility in Upton County, Texas. As part of this project, we entered a turnkey engineering, procurement and construction agreement to construct the approximately 180 MW facility. The facility began test operations in March 2018 and commercial operations began in June 2018.

CCGT Plant Acquisition — In July 2017, La Frontera Holdings, LLC (La Frontera), an indirect wholly owned subsidiary of Vistra Energy, entered into an asset purchase agreement with Odessa-Ector Power Partners, L.P., an indirect wholly owned subsidiary of Koch Ag & Energy Solutions, LLC (the Odessa Acquisition), to acquire a 1,054 MW CCGT natural gas-fueled generation plant (and other related assets and liabilities) located in Odessa, Texas (the Odessa Facility). On August 1, 2017, the Odessa Acquisition closed and La Frontera acquired the Odessa Facility. La Frontera paid an aggregate purchase price of approximately $355 million, plus a five-year earn-out provision, to acquire the Odessa Facility. The purchase price was funded by cash on hand. Subsequent to the acquisition, the earn-out provision has been accounted for as a derivative in our consolidated financial statements, and partial buybacks of the earn-out provision were settled in February and May 2018.

Retirement of Generation Plants — In August 2018, we filed a notice of suspension of operation with PJM and other mandatory regulatory notifications related to the retirement of our 51 MW Northeastern waste coal facility in McAddo, Pennsylvania. We decided to retire the facility due to its uneconomic operations and financial outlook. Following the receipt of regulatory approvals, the facility was retired in October 2018.

Two of our non-operated, jointly held power plants acquired in the Merger for which our proportional generation capacity was 883 MW, were retired in May 2018. These units were retired as previously scheduled.

In October 2017, Luminant announced plans to retire three power plants with a total installed nameplate generation capacity of approximately 4,167 MW and two lignite mines. These power plants include the Monticello, Sandow 4, Sandow 5 and Big Brown generation units. Luminant decided to retire these units because they were projected to be uneconomic based on then current market conditions and would have faced significant environmental costs associated with operating such units. In the case of the Sandow units, the decision also reflected the execution of a contract termination agreement pursuant to which the Company and Alcoa agreed to an early settlement of a long-standing power and mining agreement.

As part of the retirement process, Luminant filed notices with ERCOT, which triggered a reliability review regarding such proposed retirements. In October and November 2017, ERCOT determined the units were not needed for reliability. The Sandow and Monticello units were retired in January 2018, and the Big Brown units were retired in February 2018.

During the year ended December 31, 2017, we recorded charges of approximately $206 million related to the retirements, including employee related severance costs, noncash charges for writing off materials inventory and a contract intangible asset associated with the Big Brown plant and the acceleration of Luminant's mining reclamation obligations (see Note 23 to the Financial Statements). In addition, we will continue the ongoing reclamation work at the plants' mines.

Termination and Settlement of Alcoa Contract — In October 2017, subsidiaries of Vistra Energy (Vistra Parties) entered into a separation and settlement agreement (Settlement Agreement) with Alcoa Corporation and Alcoa USA Corp. (collectively, the Alcoa Parties). Pursuant to the Settlement Agreement, the Vistra Parties and the Alcoa Parties agreed to early termination of a series of agreements related to industrial operations near Rockdale, Texas, thereby ending their contractual relationship with respect to the power generation unit known as Sandow Unit 4 and the mine known as Three Oaks Mine. The terminated agreements were scheduled to terminate in 2038 absent the Settlement Agreement. Among other things, the Alcoa Parties made a cash payment to the Vistra Parties in the amount of approximately $238 million and transferred certain real property and related assets to the Vistra Parties, the Vistra Parties agreed to assume and be responsible for certain liabilities and asset retirement obligations related to Sandow Unit 4 (including certain related common facilities), the related mine and other property transferred from the Alcoa Parties to the Vistra Parties, and both parties released one another from any obligations and claims under the terminated agreements. The transactions under the Settlement Agreement were effective as of October 1, 2017. See Note 8 to the Financial Statements.

Dividend Program

In November 2018, we announced that the Board had adopted a dividend program pursuant to which we expect to initiate an annual dividend of approximately $0.50 per share, payable quarterly, beginning in the first quarter of 2019. Each dividend under the program will be subject to declaration by the Board and, thus, may be subject to numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, our results of operations, financial condition and liquidity and Delaware law.

On February 26, 2019, Vistra Energy announced that the Board had declared a dividend pursuant to which Vistra Energy would pay, to each holder of record as of March 15, 2019, a dividend of $0.125 per share, to be paid March 29, 2019.

Share Repurchase Program

In June 2018, we announced that the Board had authorized a share repurchase program under which up to $500 million of our outstanding common stock may be repurchased. Repurchases under this program were completed on October 19, 2018. On a cumulative basis, 21,421,925 shares of our common stock were repurchased for $500 million (including related fees and expenses) at an average price per share of common stock of $23.36.

In November 2018, we announced that the Board had authorized an incremental share repurchase program under which up to $1.25 billion of our outstanding stock may be purchased. Through December 31, 2018, 12,073,091 shares of our common stock had been repurchased for $278 million (including related fees and expenses) at an average price per share of common stock of $22.99, and at December 31, 2018, $972 million was available for additional repurchases under the program. On a cumulative basis through February 25, 2019, 19,167,147 shares of our common stock had been repurchased for $451 million (including related fees and expenses) at an average price per share of common stock of $23.52, and at February 25, 2019, $799 million was available for additional repurchases under the program. We intend to implement the program opportunistically from time to time over the next 12 months.

Shares of the Company's common stock may be repurchased in open market transactions at prevailing market prices, in privately negotiated transactions or by other means in accordance with the Securities Exchange Act of 1934, as amended, or by other means in accordance with federal securities laws. The actual timing, number and value of shares repurchased under the share repurchase program will be determined at our discretion and will depend on a number of factors, including the market price of our stock, general market and economic conditions, applicable legal requirements and compliance with the terms of our debt agreements and the Tax Matters Agreement.

Debt Activity

We have a target to reduce leverage to approximately 2.5x net debt/EBITDA. The following transactions reflect our intention to simplify our capital structure and reduce interest expense. We will continue to pursue opportunities to refinance our long-term debt and reduce interest expense.

Issuance of Vistra Operations 5.625% Senior Notes Due 2027 — In February 2019, Vistra Operations issued and sold $1.3 billion aggregate principal amount of 5.625% senior notes due 2027 in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act of 1933, as amended. The senior notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and J.P. Morgan Securities, LLC, as representative of the several initial purchasers. Net proceeds from the sale of the senior notes totaling approximately $1.287 billion, together with cash on hand, were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with (i) the 2019 cash tender offer described below, (ii) the redemption of approximately $35 million aggregate principal amount of our 7.375% senior notes due 2022 and (iii) the redemption of the remaining approximately $25 million aggregate principal amount of our outstanding 8.034% senior notes due 2024.

2019 Tender Offer and Consent Solicitation — In February 2019, Vistra Energy used the net proceeds from the issuance of the Vistra Operations 5.625% senior notes due 2027 to fund a cash tender offer (the 2019 Tender Offer) to purchase for cash approximately $1.193 billion aggregate principal amount of 7.375% senior notes due 2022 assumed in the Merger.

In connection with the 2019 Tender Offer, Vistra Energy also commenced solicitation of consents from holders of the 7.375% senior notes due 2022. Vistra Energy received the requisite consents from the holders of the 7.375% senior notes due 2022 and amended the indenture governing these senior notes to, among other things, eliminate substantially all of the restrictive covenants and certain events of default.

Bond Repurchase Program — In November 2018, the Board authorized a bond repurchase program under which up to $200 million principal amount of outstanding Vistra Energy senior notes could be repurchased. Through December 31, 2018, $119 million aggregate principal amount of senior notes had been repurchased.

Accounts Receivable Securitization Program — In August 2018, TXU Energy Receivables Company LLC (RecCo), a wholly owned subsidiary of TXU Energy, and Vistra Energy entered into a $350 million accounts receivable financing facility (Receivables Facility), currently scheduled to terminate in August 2019, with issuers of asset-backed commercial paper and commercial banks. Vistra Energy expects to have the opportunity to renew and/or extend the Receivables Facility upon its expiration subject to such terms and conditions as may be agreed upon by the parties thereto. The Receivables Facility provides Vistra Energy with the ability to borrow up to $350 million. See Note 13 to the Financial Statements for details of the accounts receivable securitization program.

Issuance of Vistra Operations 5.500% Senior Notes Due 2026 — In August 2018, Vistra Operations issued and sold $1 billion aggregate principal amount of the 5.500% senior notes due 2026 in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act of 1933, as amended. The senior notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and Citigroup Global Markets Inc., as representative of the several initial purchasers. Net proceeds from the sale of the senior notes totaling approximately $990 million, together with cash on hand and cash received from the funding of the accounts receivable securitization program described above, were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with the tender offers described below.

2018 Tender Offers and Consent Solicitations — In August 2018, Vistra Energy used the net proceeds from the issuance of the Vistra Operations 5.500% senior notes due 2026, proceeds from the accounts receivable securitization program and cash on hand to fund cash tender offers to purchase for cash $1.542 billion of senior notes assumed in the Merger. In connection with the tender offers, Vistra Energy also commenced solicitations of consents from holders of the 7.375% senior notes due 2022, the 7.625% senior notes due 2024, the 8.034% senior notes due 2024, the 8.000% senior notes due 2025 and the 8.125% senior notes due 2026 to amend certain provisions of the applicable indentures governing each series of senior notes and the registration rights agreement with respect to the 8.125% senior notes due 2026. Vistra Energy received the requisite consents from the holders of the 8.034% senior notes due 2024, the 8.000% senior notes due 2025 and the 8.125% senior notes due 2026 and amended the indentures governing each series of the applicable senior notes to, among other things, eliminate substantially all of the restrictive covenants and certain events of default. In addition, Vistra Energy received the requisite consents from the holders of the 8.125% senior notes due 2026 and amended the registration rights agreement with respect to the 8.125% senior notes due 2026 to remove, among other things, the requirement that Vistra Energy commence an exchange offer to issue registered securities in exchange for the notes.

Amendment to Vistra Operations Credit Facilities — In June 2018, the Credit Facilities Agreement was amended. Among other things, the amendment included the following updated terms:

- Aggregate commitments under the Revolving Credit Facility were increased from $860 million to $2.5 billion. The letter of credit sub-facility was also increased from $715 million to $2.3 billion. The maturity date of the Revolving Credit Facility was extended from August 4, 2021 to June 14, 2023. Pricing terms for the Revolving Credit Facility were reduced from LIBOR plus an applicable margin of 2.25% to LIBOR plus an applicable margin of 1.75%. Pricing terms for letters of credit issued under the Revolving Credit Facility were reduced from 2.25% to 1.75%.
- Pricing terms for the Term Loan B-1 Facility were reduced from LIBOR plus an applicable margin of 2.50% to LIBOR plus an applicable margin of 2.00%.
- Borrowings under the new Term Loan B-3 Facility of $2.040 billion principal amount were used to repay borrowings under the credit agreement that Vistra Energy assumed from Dynegy in connection with the Merger. Amounts borrowed under the Term Loan B-3 Facility bear interest based on applicable LIBOR rates plus a fixed spread of 2.00%, and the maturity date of the facility is December 31, 2025.
- Borrowings under the Term Loan C Facility of $500 million were repaid using $500 million of cash from collateral accounts used to backstop letters of credit.

See Note 14 to the Financial Statements for details of the Vistra Operations Credit Facilities.

Redemption of Debt — In May 2018, $850 million aggregate principal amount of outstanding 6.75% Senior Notes due 2019 was redeemed at a redemption price of 101.688% of the aggregate principal amount, plus accrued and unpaid interest to but not including the date of redemption (see Note 14).

Environmental Matters

See Note 15 to Financial Statements for a discussion of greenhouse gas emissions, the Cross-State Air Pollution Rule, regional haze, state implementation plan and other recent EPA actions as well as related litigation.

PJM — Reliability Pricing Model (RPM) auction results, for the zones in which our assets are located, are as follows for each planning year:

	2018-2019		2019-2020		2020-2021	2021-2022
	Base	CP	Base	CP	CP	CP
			(price per MW-day)			
RTO zone (a)	$ 149.98	$ 164.77	$ 80.00	$ 100.00	$ 88.32	$ 140.00
ComEd zone	200.21	215.00	182.77	202.77	188.12	195.55
MAAC zone	149.98	164.77	80.00	100.00	86.04	140.00
EMAAC zone	210.63	225.42	99.77	119.77	187.87	165.73
ATSI zone	149.88	164.77	80.00	100.00	76.53	171.33
PPL zone	75.00	164.77	80.00	100.00	86.04	140.00

(a) Planning Year 2020-2021 includes Duke Energy Ohio Kentucky (DEOK) zone which cleared at $130.00 per MW-day. RTO Zone excluding DEOK Zone was $76.53 per MW-day.

Our capacity sales, net of purchases, aggregated by planning year and capacity type through planning year 2020-2021, are as follows:

	2018-2019	2019-2020	2020-2021	2021-2022
Base auction capacity sold, net (MW)	1,420	893	—	—
CP auction capacity sold, net (MW)	7,771	8,144	8,642	9,053
Bilateral capacity sold, net (MW)	285	200	200	200
Total segment capacity sold, net (MW)	9,476	9,237	8,842	9,253
Average price per MW-day	$ 186.40	$ 135.56	$ 129.30	$ 159.22

NYISO — The most recent seasonal auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Summer 2018	Winter 2018 - 2019
Price per kW-month	$ 1.75	$ 0.35

Due to the short-term, seasonal nature of the NYISO capacity auctions, we monetize the majority of our capacity through bilateral trades. Our capacity sales, aggregated by season through summer 2021, are as follows:

	Winter 2018 - 2019	Summer 2019	Winter 2019 - 2020	Summer 2020	Winter 2020 - 2021	Summer 2021
Auction capacity sold (MW)	88	—	—	—	—	—
Bilateral capacity sold (MW)	989	540	210	75	38	20
Total capacity sold (MW)	1,077	540	210	75	38	20
Average price per kW-month	$ 1.37	$ 2.71	$ 2.57	$ 3.15	$ 3.13	$ 3.08

ISO-NE — The most recent FCA results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each planning year:

	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
Price per kW-month	$ 9.55	$ 7.03	$ 5.30	$ 4.63	$ 3.80

Performance incentive rules went into effect for planning year 2018-2019, increasing capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level. We continue to market and pursue longer term multi-year capacity transactions that extend planning year 2021-2022.

	2018-2018	2019-2020	2020-2021	2021-2022	2022-2023
Auction capacity sold (MW)	3,108	3,161	3,079	2,592	3,137
Bilateral capacity sold (MW)	239	75	150	170	95
Total capacity sold (MW)	3,347	3,236	3,229	2,762	3,232
Average price per kW-month	$ 9.80	$ 7.02	$ 5.40	$ 4.80	$ 3.92

MISO — The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each planning year:

	2018-2019
Price per MW-day	$ 10.00

MISO capacity sales through planning year 2020-2021 are as follows:

	2018-2019	2019-2020	2020-2021	2021-2022
Bilateral capacity sold in MISO (MW)	2,533	2,047	1,663	667
Base auction capacity sold in PJM (MW)	227	260	—	—
CP auction capacity sold in PJM (MW)	835	356	444	798
Total MISO segment capacity sold (MW)	3,595	2,663	2,107	1,465
Average price per kW-month	$ 3.70	$ 3.62	$ 3.81	$ 4.22

CAISO — Our capacity sales, aggregated by calendar year for 2019 through 2021 for Moss Landing, are as follows:

	2019	2020	2021
Bilateral capacity sold (Avg MW)	890	—	—

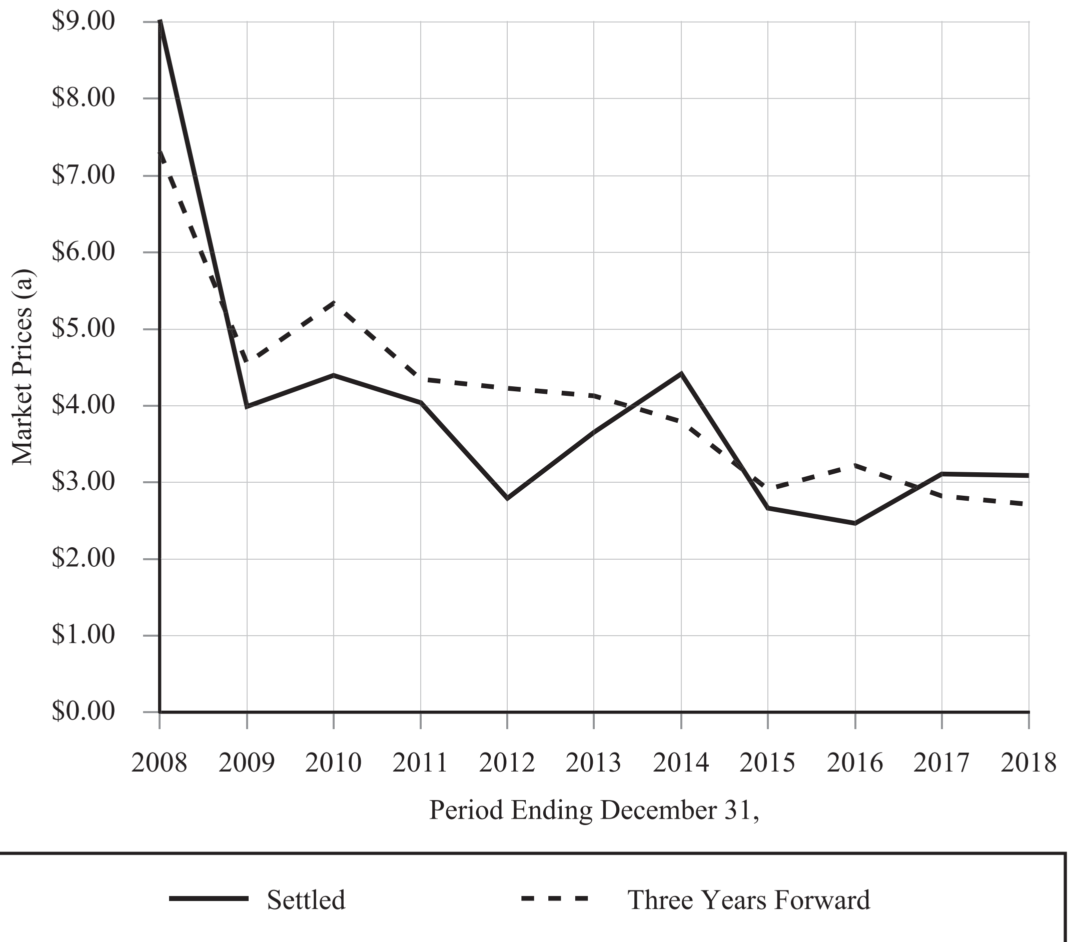
Key Operational Risks and Challenges

Following is a discussion of key operational risks and challenges facing management and the initiatives currently underway to manage such challenges. These matters involve risks that could have a material effect on our results of operations, liquidity or financial condition.

Natural Gas Price and Market Heat Rate Exposure

The price of power is typically set by natural gas-fueled generation facilities, with wholesale prices generally tracking increases or decreases in the price of natural gas. In recent years, natural gas supply has outpaced demand primarily as a result of development and expansion of hydraulic fracturing in natural gas extraction; the supply/demand imbalance has resulted in historically low natural gas prices, and such prices have historically been volatile. The table below shows the general decline in forward natural gas prices over the last several years (amounts are per MMBtu.)

Decline of Settled and Forward Natural Gas Prices Since 2008



(a) Settled prices represent the average of NYMEX Henry Hub monthly settled prices of financial contracts for the year ending on the date presented. Forward prices represent the three-year average of NYMEX Henry Hub monthly forward prices at the date presented. Three-year forward prices are presented as such period is generally deemed to be a liquid period.

In contrast to our natural gas-fueled generation facilities, changes in natural gas prices have no significant effect on the cost of generating power at our nuclear-, lignite- and coal-fueled facilities, which represent a substantial amount of our generation capacity. Consequently, all other factors being equal, these nuclear-, lignite- and coal-fueled generation assets increase or decrease in value as natural gas prices and market heat rates rise or fall, respectively, because of the effect on our operating margins from changes in wholesale electricity prices. A persistent decline in the price of natural gas, and the corresponding decline in the price of power, would likely have a material adverse effect on our results of operations, liquidity and financial condition, predominantly related to the production of power generation volumes in excess of the volumes utilized to service our retail customer load requirements.

The wholesale market price of electricity divided by the market price of natural gas represents the market heat rate. Market heat rate can be affected by a number of factors, including generation availability, mix of assets and the efficiency of the marginal supplier (generally natural gas-fueled generation facilities) in generating electricity. Our market heat rate exposure is impacted by changes in the availability of generation resources, such as additions and retirements of generation facilities, and mix of generation assets. For example, increasing renewable (wind and solar) generation capacity generally depresses market heat rates. Our heat rate exposure is also impacted by the potential economic backdown of our generation assets. Decreases in market heat rates decrease the value of our generation assets because lower market heat rates generally result in lower wholesale electricity prices, and vice versa. However, even though market heat rates have generally increased over the past several years, wholesale electricity prices have declined due to the greater effect of falling natural gas prices.

As a result of our exposure to the variability of natural gas prices and market heat rates, retail sales and hedging activities are critical to our operating results and maintaining consistent cash flow levels.

Our integrated power generation and retail electricity business provides us opportunities to hedge our generation position utilizing retail electricity markets as a sales channel. In addition, our approach to managing electricity price risk focuses on the following:

- employing disciplined, liquidity-efficient hedging and risk management strategies through physical and financial energy-related contracts intended to partially hedge gross margins;
- continuing focus on cost management to better withstand gross margin volatility;
- following a retail pricing strategy that appropriately reflects the value of our product offering to customers, the magnitude and costs of commodity price, liquidity risk and retail demand variability, and
- improving retail customer service to attract and retain high-value customers.

We have engaged in natural gas hedging activities to mitigate the risk of lower wholesale electricity prices that have corresponded to declines in natural gas prices. While current and forward natural gas prices are currently depressed, we continue to seek opportunities to manage our wholesale power price exposure through hedging activities, including forward wholesale and retail electricity sales.

Taking together forward wholesale, retail electricity sales and other retail customer considerations and all other hedging positions in ERCOT, at December 31, 2018, we had effectively hedged an estimated 99% and 91% of the natural gas price exposure related to our overall business for 2019 and 2020, respectively. These percentages assume conversion of generation positions based on market heat rates and an estimate of natural gas generally being on the margin 70% to 90% of the time in the ERCOT market. Additionally, taking into consideration our overall heat rate exposure and related hedging positions in ERCOT at December 31, 2018, we had effectively hedged 88% and 42% of the heat rate exposure to our overall business for 2019 and 2020, respectively. We make the distinction between natural gas price exposure and heat rate exposure for the ERCOT market because of the high percentage of time natural gas is on the margin and the availability of traded products in ERCOT to hedge heat rate directly. Generation volumes hedged in PJM, NYISO, ISO-NE, MISO and CAISO at December 31, 2018 were as follows:

	2019	2020
PJM	87%	57%
NYISO/ISO-NE	81%	29%
MISO/CAISO	65%	35%

The following sensitivity table provides approximate estimates of the potential impact of movements in natural gas prices and market heat rates on realized pretax earnings (in millions) taking into account the hedge positions noted in the paragraph above for the periods presented. The estimates related to price sensitivity are based on our expected generation and retail positions, related hedges and forward prices as of December 31, 2018.

	Balance 2019 (a)		2020	
ERCOT:				
$0.50/MMBtu increase in natural gas price (b)	$	~50	$	~115
$0.50/MMBtu decrease in natural gas price (b)	$	~(35)	$	~(100)
1.0/MMBtu/MWh increase in market heat rate (c)	$	~60	$	~165
1.0/MMBtu/MWh decrease in market heat rate (c)	$	~(45)	$	~(150)
PJM:				
$0.50/MMBtu increase in natural gas price (d)	$	~32	$	~93
$0.50/MMBtu decrease in natural gas price (d)	$	~(22)	$	~(72)
1.0/MMBtu/MWh increase in market heat rate (e)	$	~33	$	~71
1.0/MMBtu/MWh decrease in market heat rate (e)	$	~(26)	$	~(68)
NYISO/ISO-NE:				
$0.50/MMBtu increase in natural gas price (d)	$	~11	$	~66
$0.50/MMBtu decrease in natural gas price (d)	$	~(5)	$	~(54)
1.0/MMBtu/MWh increase in market heat rate (f)	$	~23	$	~62
1.0/MMBtu/MWh decrease in market heat rate (f)	$	~(11)	$	~(50)
MISO/CAISO:				
$0.50/MMBtu increase in natural gas price (d)	$	~85	$	~145
$0.50/MMBtu decrease in natural gas price (d)	$	~(68)	$	~(116)
1.0/MMBtu/MWh increase in market heat rate (g)	$	~47	$	~73
1.0/MMBtu/MWh decrease in market heat rate (g)	$	~(42)	$	~(65)

(a) Balance of 2019 is from February 1, 2019 through December 31, 2019.
(b) Based on Houston Ship Channel natural gas prices at December 31, 2018.
(c) Based on ERCOT North Hub around-the-clock heat rates at December 31, 2018.
(d) Based on NYMEX natural gas prices at December 31, 2018.
(e) Based on AEP Dayton Hub, Northern Illinois Hub and PJM West Hub around-the-clock heat rates at December 31, 2018.
(f) Based on Massachusetts Hub and NYISO Zone C around-the-clock heat rates at December 31, 2018.
(g) Based on Indiana Hub and NP15 around-the-clock heat rates at December 31, 2018.

Competitive Retail Markets and Customer Retention

Competitive retail activity in ERCOT has resulted in retail customer churn as customers switch retail electricity providers for various reasons. Based on numbers of meters, our total retail customer counts increased 2% in 2018, increased slightly in 2017 and declined approximately 1% in 2016. Based upon December 31, 2018 results discussed below in *Results of Operations*, a 1% decline in retail customers would result in a decline in annual revenues of approximately $55 million. In responding to the competitive landscape in the ERCOT market, we have attempted to reduce overall customer losses by focusing on the following key initiatives:

- Maintaining competitive pricing initiatives on residential service plans;
- Actively competing for new customers in areas open to competition within ERCOT, while continuing to strive to enhance the experience of our existing customers; we are focused on continuing to implement initiatives that deliver world-class customer service and improve the overall customer experience;
- Establishing and leveraging our TXU Energy™ brand in the sale of electricity to residential and commercial customers, as the most innovative retailer in the ERCOT market by continuing to develop tailored product offerings to meet customer needs, and

- Focusing market initiatives largely on programs targeted at retaining the existing highest-value customers and to recapturing customers who have switched REPs, including maintaining and continuously refining a disciplined contracting and pricing approach and economic segmentation of the business market to enhance targeted sales and marketing efforts and to more effectively deploy our direct-sales force; tactical programs we have initiated include improved customer service, aided by an enhanced customer management system, new product price/service offerings and a multichannel approach for the small business market.

Exposures Related to Nuclear Asset Outages

Our nuclear assets are comprised of two generation units at the Comanche Peak facility, each with an installed nameplate generation capacity of 1,150 MW. As of December 31, 2018, these units represented approximately 6% of our total generation capacity. The nuclear generation units represent our lowest marginal cost source of electricity. Assuming both nuclear generation units experienced an outage at the same time, the unfavorable impact to pretax earnings is estimated (based upon forward electricity market prices for 2019 at December 31, 2018) to be approximately $1 million per day before consideration of any costs to repair the cause of such outages or receipt of any insurance proceeds. Also see discussion of nuclear facilities insurance in Note 15 to the Financial Statements.

The inherent complexities and related regulations associated with operating nuclear generation facilities result in environmental, regulatory and financial risks. The operation of nuclear generation facilities is subject to continuing review and regulation by the NRC, covering, among other things, operations, maintenance, emergency planning, security, and environmental and safety protection. The NRC may implement changes in regulations that result in increased capital or operating costs and may require extended outages, modify, suspend or revoke operating licenses and impose fines for failure to comply with its existing regulations and the provisions of the Atomic Energy Act. In addition, an unplanned outage at another nuclear generation facility could result in the NRC taking action to shut down our Comanche Peak units as a precautionary measure.

We participate in industry groups and with regulators to keep current on the latest developments in nuclear safety, operation and maintenance and on emerging threats and mitigating techniques. These groups include, but are not limited to, the NRC, the Institute of Nuclear Power Operations (INPO) and the Nuclear Energy Institute (NEI). We also apply the knowledge gained through our continuing investment in technology, processes and services to improve our operations and to detect, mitigate and protect our nuclear generation assets. Management continues to focus on the safe, reliable and efficient operations at the facility.

Cyber/Data Security and Infrastructure Protection Risk

A breach of cyber/data security measures that impairs our information technology infrastructure could disrupt normal business operations and affect our ability to control our generation assets, access retail customer information and limit communication with third parties. Any loss of confidential or proprietary data through a breach could materially affect our reputation, including our TXU Energy™, Dynegy Energy Services and Homefield Energy brands, expose the company to legal claims or impair our ability to execute on business strategies.

We participate in industry groups and with regulators to remain current on emerging threats and mitigating techniques. These groups include, but are not limited to, the U.S. Cyber Emergency Response Team, the National Electric Sector Cyber Security Organization, the NRC and NERC.

While the company has not experienced a cyber/data event causing any material operational, reputational or financial impact, we recognize the growing threat within the general market place and our industry, and are proactively making strategic investments in our perimeter and internal defenses, cyber/data security operations center and regulatory compliance activities. We also apply the knowledge gained through industry and government organizations to continuously improve our technology, processes and services to detect, mitigate and protect our cyber and data assets.

Seasonality

The demand for and market prices of electricity and natural gas are affected by weather. As a result, our operating results may fluctuate on a seasonal basis. Typically, demand for and the price of electricity is higher in the summer and winter seasons, when the temperatures are more extreme, and the demand for and price of natural gas is also generally higher in the winter. More severe weather conditions such as heat waves or extreme winter weather may make such fluctuations more pronounced. However, not all regions of the U.S. typically experience extreme weather conditions at the same time, so Vistra Energy is typically not exposed to the effects of extreme weather in all parts of its business at once. The pattern of this fluctuation may change depending on, among other things, the retail load served and the terms of contracts to purchase or sell electricity.

Application of Critical Accounting Policies

Our significant accounting policies are discussed in Note 1 to the Financial Statements. We follow accounting principles generally accepted in the U.S. Application of these accounting policies in the preparation of our consolidated financial statements requires management to make estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and revenues and expenses during the periods covered. The following is a summary of certain critical accounting policies that are impacted by judgments and uncertainties and under which different amounts might be reported using different assumptions or estimation methodologies.

Purchase Accounting

On the Merger Date, Dynegy merged with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. The Merger is being accounted for in accordance with ASC 805, Business Combinations (ASC 805), with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the Merger Date. Vistra Energy is the acquirer for both federal tax and accounting purposes. The combined results of operations are reported in our consolidated financial statements beginning as of the Merger Date. See Note 2 to the Financial Statements.

During the measurement period, which is up to one year from the Merger date, we record adjustments to the initial estimates in the reporting period in which the adjustment amounts are determined based on facts and circumstances that existed as of the acquisition date. We expect to finalize our purchase price allocation in the quarter ended March 31, 2019. Upon the conclusion of the measurement period, any subsequent adjustments will be recorded to earnings. Transaction costs have been expensed as incurred.

The acquired assets and liabilities that involved the most subjectivity in determining fair value consisted of property, plant and equipment and executory contracts, primarily long-term service agreements for maintenance of power plants and a unit-specific power sales agreement. The fair value of each power plant was estimated using a combination of an income approach and a market approach. The income approach is the present value of future cash flows over the life of each power plant that are based on management's estimates of revenues and operating expenses, and appropriate discount rates. The estimate of long term prices of electricity and natural gas at each plant location that was used in developing forecasted revenues for the income approach was especially subjective, because as of the Merger Date, limited market information about future prices beyond the year 2022 was available. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the relevant market, with adjustments relating to any differences between the assets and locations. The determination of deferred tax assets was complex as it required assessing income tax rules and regulations and proposed regulations that impose limitations on the future use of acquired net operating losses and other limitations on deductions.

Accounting in Reorganization and Fresh-Start Reporting

The consolidated financial statements of our Predecessor reflect the application of ASC 852. During the Chapter 11 Cases, the Debtors, including our Predecessor and its subsidiaries, operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. ASC 852 applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities. Expenses and income directly associated with the Chapter 11 Cases are reported separately in the statements of consolidated income (loss) as reorganization items. Reorganization items also include adjustments to reflect the carrying value of liabilities subject to compromise (LSTC) at their estimated allowed claim amounts, as such adjustments are determined. See Note 5 to the Financial Statements.

As of the Effective Date, Vistra Energy applied fresh-start reporting under the applicable provisions of ASC 852. Fresh-start reporting includes (1) distinguishing the consolidated financial statements of the entity that was previously in restructuring from the consolidated financial statements of the entity that emerges from restructuring, (2) assigning the reorganized value of the successor entity by measuring all assets and liabilities of the successor entity at fair value, and (3) selecting accounting policies for the successor entity. The effects from emerging from bankruptcy, including the extinguishment of liabilities, as well as the fresh start reporting adjustments are reported in the Predecessor's statement of consolidated income (loss). The consolidated financial statements of Vistra Energy for periods subsequent to the Effective Date are not comparable to the financial statements of our Predecessor for periods prior to the Effective Date, as those previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities, nor any differences in accounting policies that were a consequence of the Plan of Reorganization or the related application of fresh-start reporting. See Note 6 to the Financial Statements.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of energy-related commodities, and also enter into other derivative instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. Under accounting standards related to derivative instruments and hedging activities, these instruments are subject to mark-to-market accounting, and the determination of market values for these instruments is based on numerous assumptions and estimation techniques.

Mark-to-market accounting recognizes changes in the fair value of derivative instruments in the financial statements as market prices change. Such changes in fair value are accounted for as unrealized mark-to-market gains and losses in net income with an offset to derivative assets and liabilities. The availability of quoted market prices in energy markets is dependent on the type of commodity (*e.g.*, natural gas, electricity, etc.), time period specified and delivery point. In computing fair value for derivatives, each forward pricing curve is separated into liquid and illiquid periods. The liquid period varies by delivery point and commodity. Generally, the liquid period is supported by exchange markets, broker quotes and frequent trading activity. For illiquid periods, fair value is estimated based on forward price curves developed using modeling techniques that take into account available market information and other inputs that might not be readily observable in the market. We estimate fair value as described in Note 17 to the Financial Statements.

Accounting standards related to derivative instruments and hedging activities allow for normal purchase or sale elections and hedge accounting designations, which generally eliminate or defer the requirement for mark-to-market recognition in net income and thus reduce the volatility of net income that can result from fluctuations in fair values. Normal purchases and sales are contracts that provide for physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business and are not subject to mark-to-market accounting if the normal purchase or sale election is made. Accounting standards also permit an entity to designate certain qualifying derivative contracts in a hedge accounting relationship, whereby changes in fair value are not recognized immediately in earnings. Vistra Energy does not have derivative instruments with hedge accounting designations.

We report derivative assets and liabilities in the consolidated balance sheets without taking into consideration netting arrangements that we have with counterparties. Margin deposits that contractually offset these assets and liabilities are reported separately in the consolidated balance sheets, with the exception of certain margin amounts related to changes in fair value on CME transactions that, beginning in January 2017, are legally characterized as settlement of derivative contracts rather than collateral.

See Note 18 to the Financial Statements for further discussion regarding derivative instruments.

Accounting for Income Taxes

Subsequent to the Effective Date, Vistra Energy files a United States federal income tax return that includes the results of its consolidated subsidiaries. Vistra Energy is the corporate parent of the Vistra Energy consolidated group. Pursuant to applicable United States Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group.

Our income tax expense and related consolidated balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates and judgments of the timing and probability of recognition of income and deductions by taxing authorities. In assessing the likelihood of realization of deferred tax assets, management considers estimates of the amount and character of future taxable income. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, our forecasted financial condition and results of operations in future periods, as well as final review of filed tax returns by taxing authorities. Income tax returns are regularly subject to examination by applicable tax authorities. In management's opinion, the liability recorded pursuant to income tax accounting guidance related to uncertain tax positions reflects future taxes that may be owed as a result of any examination.

Our deferred tax assets were significantly impacted by the TCJA, which reduced the overall federal corporate rate from 35% to 21%. This rate change decreased our overall deferred tax asset balance by approximately $451 million during the year ended December 31, 2017.

See Notes 1 and 9 to the Financial Statements for discussion of income tax matters.

Accounting for Tax Receivable Agreement

On the Effective Date, we entered into a tax receivable agreement (the TRA) with a transfer agent. Pursuant to the TRA, we issued beneficial interests in the rights to receive payments under the TRA (the TRA Rights) to the first lien creditors of our Predecessor to be held in escrow for the benefit of the first lien creditors of our Predecessor entitled to receive such TRA Rights under the Plan of Reorganization. Vistra Energy reflected the obligation associated with TRA Rights at fair value in the amount of $574 million as of the Emergence Date related to these future payment obligations. As of December 31, 2018, the TRA obligation has been adjusted to $420 million. During the year ended December 31, 2018, we recorded an increase to the carrying value of the TRA obligation totaling $14 million. The largest driver in the increase to the TRA obligation carrying value primarily resulted from in the timing of estimated payments and new multistate tax impacts resulting from the Merger, which increased the total expected undiscounted payments under the TRA from $1.2 billion to $1.4 billion. The TRA obligation value is the discounted amount of estimated payments to be made each year under the TRA, based on certain assumptions, including but not limited to:

- the amount of tax basis related to (i) the Lamar and Forney acquisition and (ii) step-up resulting from the PrefCo Preferred Stock Sale (which is estimated to be approximately $5.5 billion) and the allocation of such tax basis step-up among the assets subject thereto;
- the depreciable lives of the assets subject to such tax basis step-up, which generally is expected to be 15 years for most of such assets;
- a blended federal/state corporate income tax rate in all future years of 23%;
- future taxable income by year for future years;
- the Company generally expects to generate sufficient taxable income to be able to utilize the deductions arising out of (i) the tax basis step up attributable to the PrefCo Preferred Stock Sale, (ii) the entire tax basis of the assets acquired as a result of the Lamar and Forney Acquisition, and (iii) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA in the tax year in which such deductions arise;
- a discount rate of 15%, which represented our view at the Emergence Date of the rate that a market participant would use based on the risk associated with the uncertainty in the amount and timing of the cash flows, at the time of Emergence, and
- additional states that Vistra Energy now operates in, the relevant tax rates of those states and how income will be apportioned to those states.

We recognize accretion expense over the life of the TRA Rights liability as the present value of the liability is accreted up over the life of the liability. This noncash accretion expense is reported in the statements of consolidated income (loss) as Impacts of Tax Receivable Agreement. Further, there may be significant changes, which may be material, to the estimate of the related liability due to various reasons including changes in corporate tax law, changes in estimates of the amount or timing of future taxable income of Vistra Energy and its subsidiaries and other items. Changes in those estimates are recognized as adjustments to the related TRA Rights liability, with offsetting impacts recorded in the statements of consolidated income (loss) as Impacts of Tax Receivable Agreement. See Note 10 to the Financial Statements.

Asset Retirement Obligations (ARO)

As part of fresh start reporting, new fair values were established for all AROs for the Successor. As part of business combination accounting, new fair values were established for all AROs assumed in the Merger. A liability is initially recorded at fair value for an asset retirement obligation associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets in the period in which it is incurred if a fair value is reasonably estimable. Generally, changes in estimates related to ARO obligations are recorded as increases or decreases to the liability and related asset as information becomes available. Changes in estimates related to assets that have been retired or for which capitalized costs are not recoverable are reflected in the statement of consolidated income (loss).

During the year ended December 31, 2017, we recorded additional ARO obligations totaling $112 million primarily reflecting the acceleration of ARO obligations due to the retirements of our Monticello, Sandow and Big Brown plants. In addition, we recorded additional ARO obligations totaling $62 million as part of acquiring certain real property through the Alcoa contract settlement.

See Note 23 to the Financial Statements for additional discussion of ARO obligations.

Impairment of Goodwill and Other Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment, in accordance with accounting standards related to impairment or disposal of long-lived assets, whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. For our generation assets, possible indications include an expectation of continuing long-term declines in natural gas prices and/or market heat rates or an expectation that "more likely than not" a generation asset will be sold or otherwise disposed of significantly before the end of its estimated useful life. The determination of the existence of these and other indications of impairment involves judgments that are subjective in nature and may require the use of estimates in forecasting future results and cash flows related to an asset or group of assets. Further, the unique nature of our property, plant and equipment, which includes a fleet of generation assets with a diverse fuel mix and individual generation units that have varying production or output rates, requires the use of significant judgments in determining the existence of impairment indications and the grouping of assets for impairment testing. We generally utilize an income approach measurement to derive fair values for our long-lived generation assets. The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, market heat rates, the effects of environmental rules, generation plant performance, forecasted capital expenditures and forecasted fuel prices. Any significant change to one or more of these factors can have a material impact on the fair value measurement of our long-lived assets. Additional material impairments related to our generation facilities may occur in the future if forward wholesale electricity prices decline in the markets in which we operate in or if additional environmental regulations increase the cost of producing electricity at our generation facilities.

Goodwill and intangible assets with indefinite useful lives, such as the intangible asset related to the TXU Energy™, 4Change Energy™, Homefield and Dynegy Energy Services brands, are required to be tested for impairment at least annually (as of the Effective Date, we have selected October 1 as our annual test date) or whenever events or changes in circumstances indicate an impairment may exist, such as the indicators used to evaluate impairments to long-lived assets discussed above or declines in values of comparable public companies in our industry. Accounting standards allow a company to qualitatively assess if the carrying value of a reporting unit with goodwill is more likely than not less than the fair value of that reporting unit. If the entity determines the carrying value, including goodwill, is not more likely greater than the fair value, no further testing of goodwill for impairment is required. On the most recent goodwill testing date, we applied qualitative factors and determined that it was more likely than not that the fair value of our ERCOT Retail reporting unit exceeded its carrying value at October 1, 2018. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, cost factors, customer attrition, interest rates and changes in reporting unit book value.

Accounting guidance requires goodwill to be allocated to our reporting units, and at December 31, 2018, $1.907 billion of our goodwill was allocated to our ERCOT Retail reporting unit and $161 million arose in connection with the Merger and is recorded at the corporate and other level non-segment operations pending completion of the purchase price allocation in the first quarter of 2019, at which time goodwill will be allocated to reporting units. Goodwill impairment testing is performed at the reporting unit level. Under this goodwill impairment analysis, if at the assessment date, a reporting unit's carrying value exceeds its estimated fair value (enterprise value), the estimated enterprise value of the reporting unit is compared to the estimated fair values of the reporting unit's assets (including identifiable intangible assets) and liabilities at the assessment date, and the resultant implied goodwill amount is then compared to the recorded goodwill amount. Any excess of the recorded goodwill amount over the implied goodwill amount is written off as an impairment charge.

The determination of enterprise value involves a number of assumptions and estimates. We use a combination of fair value measurements to estimate enterprise values of our reporting units including: internal discounted cash flow analyses (income approach), and comparable publicly traded company values (market approach). The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, market heat rates, the effects of environmental rules, generation plant performance, forecasted capital expenditures and retail sales volume trends, as well as determination of a terminal value. Another key variable in the income approach is the discount rate, or weighted average cost of capital, applied to the forecasted cash flows. The determination of the discount rate takes into consideration the capital structure, credit ratings and current debt yields of comparable publicly traded companies as well as an estimate of return on equity that reflects historical market returns and current market volatility for the industry. The market approach involves using trading multiples of EBITDA of those selected publicly traded companies to derive appropriate multiples to apply to the EBITDA of our reporting units. Critical judgments include the selection of publicly traded comparable companies and the weighting of the value metrics in developing the best estimate of enterprise value.

RESULTS OF OPERATIONS

Vistra Energy Consolidated Financial Results — Successor Years Ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016

	Successor			
	Year Ended December 31,		Favorable (Unfavorable) $ Change	Period from October 3, 2016 through December 31, 2016
	2018	2017		
Operating revenues	$ 9,144	$ 5,430	$ 3,714	$ 1,191
Fuel, purchased power costs and delivery fees	(5,036)	(2,935)	(2,101)	(720)
Operating costs	(1,297)	(973)	(324)	(208)
Depreciation and amortization	(1,394)	(699)	(695)	(216)
Selling, general and administrative expenses	(926)	(600)	(326)	(208)
Impairment of long-lived assets	—	(25)	25	—
Operating income	491	198	293	(161)
Other income	47	37	10	10
Other deductions	(5)	(5)	—	—
Interest expense and related charges	(572)	(193)	(379)	(60)
Impacts of Tax Receivable Agreement	(79)	213	(292)	(22)
Equity in earnings of unconsolidated investment	17	—	17	—
Income before income taxes	(101)	250	(351)	(233)
Income tax (expense) benefit	45	(504)	549	70
Net income (loss)	$ (56)	$ (254)	$ 198	$ (163)

	Successor							
	Year Ended December 31, 2018							
	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Operating revenues	$ 5,597	$ 2,634	$ 1,725	$ 817	$ 720	$ 50	$ (2,399)	$ 9,144
Fuel, purchased power costs and delivery fees	(4,126)	(1,521)	(917)	(485)	(420)	(40)	2,473	(5,036)
Operating costs	(39)	(677)	(243)	(74)	(202)	(43)	(19)	(1,297)
Depreciation and amortization	(318)	(416)	(413)	(152)	(9)	—	(86)	(1,394)
Selling, general and administrative expenses	(424)	(90)	(52)	(36)	(53)	(17)	(254)	(926)
Operating income (loss)	690	(70)	100	70	36	(50)	(285)	491
Other income	29	34	1	—	—	2	(19)	47
Other deductions	—	(7)	—	—	—	(1)	3	(5)
Interest expense and related charges	(7)	(12)	(8)	(2)	(1)	—	(542)	(572)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	(79)	(79)
Equity in earnings of unconsolidated investment	—	—	7	11	—	—	(1)	17
Income (loss) before income taxes	712	(55)	100	79	35	(49)	(923)	(101)
Income tax benefit	—	—	—	—	—	—	45	45
Net income (loss)	$ 712	$ (55)	$ 100	$ 79	$ 35	$ (49)	$ (878)	$ (56)

	Successor				
	Year Ended December 31, 2017				
	Retail	ERCOT	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Operating revenues	$ 4,058	$ 1,794	$ 964	$ (1,386)	$ 5,430
Fuel, purchased power costs and delivery fees	(2,733)	(981)	(607)	1,386	(2,935)
Operating costs	(14)	(578)	(380)	(1)	(973)
Depreciation and amortization	(430)	(229)	(1)	(39)	(699)
Selling, general and administrative expenses	(420)	(124)	(19)	(37)	(600)
Impairment of long-lived assets	—	—	(25)	—	(25)
Operating income (loss)	461	(118)	(68)	(77)	198
Other income	34	24	6	(27)	37
Other deductions	—	(3)	(1)	(1)	(5)
Interest expense and related charges	—	(21)	—	(172)	(193)
Impacts of Tax Receivable Agreement	—	—	—	213	213
Income (loss) before income taxes	495	(118)	(63)	(64)	250
Income tax expense	—	—	—	(504)	(504)
Net income (loss)	$ 495	$ (118)	$ (63)	$ (568)	$ (254)

We believe 2018 was a very successful year for Vistra Energy. We completed the transformational Merger with Dynegy in April. We reduced post-acquisition consolidated debt by approximately $1.7 billion and refinanced an additional approximately $11 billion of debt and revolving credit commitments at lower interest rates and extended maturities. We completed construction of the Upton 2 solar project and our first battery storage facility located at the Upton 2 site. In addition, we were awarded a contract to develop the largest battery storage facility in North America. In 2018, we also executed a balanced capital allocation plan, returning approximately $762 million to stockholders via share repurchases. For the year ended December 31, 2018, net loss includes $380 million in unrealized mark-to-market losses on commodity risk management activity in 2018 resulting from higher forward power prices, principally driven by higher market heat rates. Our operating segments delivered strong operating performance with a disciplined focus on cost management, while generating and selling electricity in a safe and reliable manner.

Consolidated results increased $198 million to net loss of $56 million in the year ended December 31, 2018 compared to the year ended December 31, 2017. The change in results was driven by additional operations acquired in the Merger, increased prices and volumes in the ERCOT segment, favorable volumes in the Retail segment, and the impact of the Comanche Peak outage in 2017 and related insurance proceeds, partially offset by increased unrealized mark-to-market losses on commodity risk management activity, one-time Merger-related expenses including severance and transaction fees and the first quarter of 2018 plant retirements.

Interest expense and related charges increased $379 million to $572 million in the year ended December 31, 2018 compared to the year ended December 31, 2017 and reflected a $324 million increase in interest expense incurred reflecting long-term debt assumed in the Merger, $34 million change in unrealized mark-to-market gains/losses on interest rate swaps and a debt extinguishment loss of $27 million in 2018. See Note 11 to the Financial Statements.

For the year ended December 31, 2018, the Impacts of the Tax Receivable Agreement totaled expense of $79 million and reflected a loss due to changes in the estimated amount and timing of TRA payments totaling $14 million and accretion expense totaling $65 million. For the year ended December 31, 2017, the Impacts of the Tax Receivable Agreement totaled income of $213 million and reflected a gain due to changes in the estimated timing of TRA payments totaling $295 million, partially offset by accretion expense totaling $82 million. See Note 10 to the Financial Statements for discussion of the impacts of the Tax Receivable Agreement Obligation.

For the year ended December 31, 2018, income tax benefit totaled $45 million and the effective tax rate was 44.6%. For the year ended December 31, 2017, income tax expense totaled $504 million. The effective tax rate in 2017 of 201.6% was higher than the U.S. Federal Statutory rate of 35% primarily due to a $451 million reduction of deferred tax assets related to the decrease in the corporate rate in the TCJA, partially offset by $80 million of tax impacts related to nondeductible TRA accretion. See Note 9 to the Financial Statements for reconciliation of the effective rates to the U.S. federal statutory rate.

	Successor				
	Period from October 3, 2016 through December 31, 2016				
	Retail	ERCOT	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Operating revenues	$ 912	$ 212	$ 238	$ (171)	$ 1,191
Fuel, purchased power costs and delivery fees	(515)	(214)	(162)	171	(720)
Operating costs	(3)	(151)	(54)	—	(208)
Depreciation and amortization	(153)	(53)	—	(10)	(216)
Selling, general and administrative expenses	(130)	(65)	(6)	(7)	(208)
Operating income (loss)	111	(271)	16	(17)	(161)
Other income	3	2	1	4	10
Interest expense and related charges	—	1	—	(61)	(60)
Impacts of Tax Receivable Agreement	—	—	—	(22)	(22)
Income (loss) before income taxes	114	$ (268)	$ 17	(96)	(233)
Income tax benefit	—	—	—	70	70
Net income (loss)	$ 114	$ (268)	$ 17	$ (26)	$ (163)

Consolidated net loss totaled $163 million for the period from October 3, 2016 through December 31, 2016. Results were primarily driven by:

- Retail segment net income of $114 million for the period, which was primarily driven by favorable profit margins, including $113 million of unrealized gains in purchased power costs on positions with the ERCOT segment.
- ERCOT segment net loss of $268 million for the period, which was primarily driven by unrealized mark-to-market losses on commodity risk management activities totaling $273 million for the period (including $113 million of unrealized losses on positions with the Retail segment and $22 million of unrealized gains on hedging activities for fuel and purchased power costs). The unrealized losses were driven by increases in forward natural gas prices during the period.

Interest expense and related charges totaled $60 million and reflected $51 million of interest expense incurred and $11 million of unrealized mark-to-market losses on interest rate swaps (see Note 11 to the Financial Statements).

Impacts of the Tax Receivable Agreement were a loss of $22 million, which reflected accretion expense during the period. See Note 10 to the Financial Statements for discussion of the impacts of the Tax Receivable Agreement obligation.

Income tax benefit totaled $70 million. The effective tax rate was 30.0%. See Note 9 to the Financial Statements for reconciliation of this effective rate to the U.S. federal statutory rate.

Discussion of Adjusted EBITDA

Non-GAAP Measures — In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA as performance measures. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our GAAP results and the accompanying reconciliations to corresponding GAAP financial measures included in the tables below, may provide a more complete understanding of factors and trends affecting our business. These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are by definition an incomplete understanding of Vistra Energy and must be considered in conjunction with GAAP measures. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

EBITDA and Adjusted EBITDA — We believe EBITDA and Adjusted EBITDA provide meaningful representations of our operating performance. We consider EBITDA as another way to measure financial performance on an ongoing basis. Adjusted EBITDA is meant to reflect the operating performance of our segments for the period presented. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit) and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale or retirement of certain assets, (ii) the impacts of mark-to-market changes on derivatives related to our portfolio, (iii) the impact of impairment charges, (iv) certain amounts associated with fresh-start reporting, acquisitions, dispositions, transition costs or restructurings, (v) non-cash compensation expense, (vi) impacts from the Tax Receivable Agreement and (vii) other material nonrecurring or unusual items.

Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers, and evaluate overall financial performance, we believe they provide useful information for our shareholders.

When EBITDA or Adjusted EBITDA is discussed in reference to performance on a consolidated basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is Net income (loss).

Adjusted EBITDA — Successor Years Ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016

	Successor			
	Year Ended December 31, 2018	Year Ended December 31, 2017	Favorable (Unfavorable) $ Change	Period from October 3, 2016 through December 31, 2016
Net income (loss)	$ (56)	$ (254)	$ 198	$ (163)
Income tax expense (benefit)	(45)	504	(549)	(70)
Interest expense and related charges	572	193	379	60
Depreciation and amortization (a)	1,472	781	691	247
EBITDA before Adjustments	1,943	1,224	719	74
Unrealized net loss resulting from hedging transactions	380	146	234	165
Generation plant retirement expenses	—	206	(206)	—
Fresh start/purchase accounting impacts	41	59	(18)	35
Impacts of Tax Receivable Agreement	79	(213)	292	22
Reorganization items and restructuring expenses	—	3	(3)	18
Non-cash compensation expenses	73	19	54	—
Transition and merger expenses	233	27	206	—
Severance	—	—	—	44
Other, net	(7)	(16)	9	10
Adjusted EBITDA, including Odessa earnout buybacks	$ 2,742	$ 1,455	$ 1,287	$ 368
Odessa earnout buybacks	18	—	18	
Adjusted EBITDA	$ 2,760	$ 1,455	$ 1,305	

(a) Includes nuclear fuel amortization in the ERCOT segment of $78 million, $82 million and $31 million for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016, respectively.

	Successor							
	Year Ended December 31, 2018							
	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Net income (loss)	$ 712	$ (55)	$ 100	$ 79	$ 35	$ (49)	$ (878)	$ (56)
Income tax benefit	—	—	—	—	—	—	(45)	(45)
Interest expense and related charges	7	12	8	2	1	—	542	572
Depreciation and amortization (a)	318	494	413	152	9	—	86	1,472
EBITDA before Adjustments	1,037	451	521	233	45	(49)	(295)	1,943
Unrealized net (gain) loss resulting from hedging transactions	(206)	498	42	40	(9)	—	15	380
Fresh start/purchase accounting impacts	26	(6)	(1)	9	12	1	—	41
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	79	79
Non-cash compensation expenses	—	—	—	—	—	—	73	73
Transition and merger expenses	1	9	14	2	9	2	196	233
Other, net	(13)	(2)	16	9	9	(3)	(23)	(7)
Adjusted EBITDA, including Odessa earnout buybacks	845	950	592	293	66	(49)	$ 45	2,742
Odessa earnout buybacks		18						18
Adjusted EBITDA	$ 845	$ 968	$ 592	$ 293	$ 66	$ (49)	$ 45	$ 2,760

(a) Includes nuclear fuel amortization of $78 million in ERCOT segment.

	Successor				
	Year Ended December 31, 2017				
	Retail	ERCOT	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Net income (loss)	$ 495	$ (118)	$ (63)	$ (568)	$ (254)
Income tax expense	—	—	—	504	504
Interest expense and related charges	—	21	—	172	193
Depreciation and amortization (a)	430	311	1	39	781
EBITDA before Adjustments	925	214	(62)	147	1,224
Unrealized net (gain) loss resulting from hedging transactions	(171)	317	—	—	146
Generation plant retirement expenses	—	—	206	—	206
Fresh start accounting impacts	46	(1)	14	—	59
Impacts of Tax Receivable Agreement	—	—	—	(213)	(213)
Reorganization items and restructuring expenses	—	—	—	3	3
Non-cash compensation expenses	—	—	—	19	19
Transition and merger expenses	1	8	—	18	27
Other, net	(22)	—	—	6	(16)
Adjusted EBITDA	$ 779	$ 538	$ 158	$ (20)	$ 1,455

(a) Includes nuclear fuel amortization of $82 million in ERCOT segment.

Adjusted EBITDA increased by $1,305 million to $2,760 million in the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to the following:

PJM, MISO and NY/NE segments acquired in the Merger	$ 950
Increase in ERCOT segment driven by operations acquired in the Merger and Odessa, higher realized prices and the impact of the Comanche Peak outage in 2017 and related insurance proceeds in 2018	430
Increase in Retail segment driven by favorable volumes in ERCOT and Midwest/Northeast retail businesses acquired in the Merger	66
Decrease in Asset Closure segment driven by retirement of facilities in first quarter of 2018, partially offset by the change in estimates for certain AROs in 2018	(207)
Corporate and Other due in part to operations acquired in the Merger	66
Total	$ 1,305

	Successor				
	Period from October 3, 2016 through December 31, 2016				
	Retail	ERCOT	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Net income (loss)	$ 114	$ (268)	$ 17	$ (26)	$ (163)
Income tax benefit	—	—	—	(70)	(70)
Interest expense and related charges	—	(1)	—	61	60
Depreciation and amortization (a)	153	84	—	10	247
EBITDA before Adjustments	267	(185)	17	(25)	74
Unrealized net (gain) loss resulting from hedging transactions	(107)	272	—	—	165
Fresh start accounting impacts	36	(4)	3	—	35
Impacts of Tax Receivable Agreement	—	—	—	22	22
Reorganization items and restructuring expenses	7	7	—	4	18
Severance	9	33	2	—	44
Other, net	1	9	—	—	10
Adjusted EBITDA	$ 213	$ 132	$ 22	$ 1	$ 368

(a) Includes nuclear fuel amortization of $31 million in ERCOT segment.

Retail Segment — Year Ended December 31, 2018 Compared to Year Ended December 31, 2018

	Year Ended December 31, 2018	Year Ended December 31, 2017	Favorable (Unfavorable) Change
Operating revenues:			
Revenues in ERCOT	$ 4,426	$ 4,002	$ 424
Revenues in Northeast/Midwest	1,123	—	1,123
Amortization expense	(26)	(46)	20
Other revenues	74	102	(28)
Total operating revenues	**$ 5,597**	**$ 4,058**	**$ 1,539**
Fuel, purchased power costs and delivery fees:			
Purchases from affiliates	(2,846)	(1,539)	(1,307)
Unrealized net gains on hedging activities with affiliates	218	154	64
Delivery fees	(1,493)	(1,345)	(148)
Other costs	(5)	(3)	(2)
Total fuel, purchased power costs and delivery fees	**$ (4,126)**	**$ (2,733)**	**$ (1,393)**
Net income	**$ 712**	**$ 495**	**$ 217**
Adjusted EBITDA	**$ 845**	**$ 779**	**$ 66**
Sales volumes (GWh):			
Retail electricity sales volumes:			
Sales volumes in ERCOT	42,992	39,032	3,960
Sales volumes in Northeast/Midwest	20,739	—	20,739
Total retail electricity sales volumes	63,731	39,032	24,699
Weather (North Texas average) - percent of normal (a):			
Cooling degree days	103.0%	99.1%	
Heating degree days	112.0%	72.0%	

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(a) Weather data is obtained from Weatherbank, Inc. For the year ended December 31, 2018, normal is defined as the average over the 10-year period from 2008 to 2017. For the year ended December 31, 2017, normal is defined as the average over the 10-year period from 2007 to 2016.

Net income increased by $217 million to net income of $712 million and Adjusted EBITDA increased by $66 million to $845 million and in the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to the following:

Favorable volumes primarily due to weather in ERCOT	$ 53
Margins in Midwest/Northeast acquired in the Merger	34
Unfavorable margins in ERCOT primarily due to higher power costs	(21)
Change in Adjusted EBITDA	**$ 66**
Lower depreciation and amortization expenses driven by reduced amortization of the retail customer relationship	132
Favorable impact of unrealized net gains on hedging activities	34
Higher other expenses	(15)
Change in Net income	**$ 217**

ERCOT Segment — Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

	Year Ended December 31, 2018	Year Ended December 31, 2017	Favorable (Unfavorable) Change
Operating revenues:			
Wholesale electricity sales	$ 1,289	$ 523	$ 766
Sales to affiliates	1,829	1,539	290
Rolloff of unrealized net gains (losses) representing positions settled in the current period	404	(184)	588
Unrealized net gains (losses) from changes in fair value	(689)	33	(722)
Unrealized net losses on hedging activities with affiliates	(198)	(154)	(44)
Other revenues	(1)	37	(38)
Operating revenues	**$ 2,634**	**$ 1,794**	**$ 840**
Fuel, purchased power costs and delivery fees:			
Fuel for generation facilities and purchased power costs	(1,367)	(881)	(486)
Unrealized losses from hedging activities	(15)	(12)	(3)
Ancillary and other costs	(139)	(88)	(51)
Fuel, purchased power costs and delivery fees	**$ (1,521)**	**$ (981)**	**$ (540)**
Net loss	**$ (55)**	**$ (118)**	**$ 63**
Adjusted EBITDA	**$ 968**	**$ 538**	**$ 430**
Production volumes (GWh):			
Nuclear facilities	20,416	16,921	3,495
Lignite and coal facilities	29,151	26,043	3,108
Natural gas facilities	35,790	18,522	17,268
Solar facilities	344	—	344
Capacity factors:			
Nuclear facilities	101.3%	84.0%	
Lignite and coal facilities	76.9%	77.2%	
CCGT facilities	58.8%	52.3%	
Market pricing:			
Average ERCOT North power price ($/MWh)	$ 29.96	$ 23.26	$ 6.70

Net loss increased by $63 million to $55 million net loss and Adjusted EBITDA increased by $430 million to $968 million in the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to the following:

Favorable margins driven by higher realized power prices and increased production from legacy gas and coal generation	$	180
Impact of operations acquired in the Merger		73
Impact related to Comanche Peak outage in 2017		74
Impact of full year of operations from Odessa acquired in 2017		86
Lower selling, general and administrative expenses		34
Insurance reimbursement for Comanche Peak		21
Other		(38)
Change in Adjusted EBITDA	**$**	**430**
Increased depreciation and amortization driven by facilities acquired in the Merger		(183)
Unfavorable impact of unrealized net losses on hedging activities		(182)
Partial buybacks of the Odessa earn-out provision in 2018		(18)
Other		(2)
Change in Net loss	**$**	**63**

PJM, NY/NE and MISO Segments — Year Ended December 31, 2018

	Year Ended December 31, 2018		
	PJM	NY/NE	MISO
Operating revenues:			
Energy	$ 775	$ 582	$ 370
Capacity	369	239	53
Unrealized net gains (losses) on hedging activities	(17)	(37)	(13)
Sales to affiliates	628	44	302
Unrealized net gains (losses) on hedging activities with affiliates	(33)	(3)	16
Other revenues	3	(8)	(8)
Operating revenues	**$ 1,725**	**$ 817**	**$ 720**
Fuel, purchased power costs and delivery fees:			
Fuel for generation facilities and purchased power costs	(916)	(479)	(449)
Fuel for generation facilities and purchased power costs from affiliates	(8)	—	30
Unrealized gains from hedging activities	8	—	6
Other costs	(1)	(6)	(7)
Fuel, purchased power costs and delivery fees	**$ (917)**	**$ (485)**	**$ (420)**
Net income	**$ 100**	**$ 79**	**$ 35**
Adjusted EBITDA	**$ 592**	**$ 293**	**$ 66**
Production volumes (GWh)	40,533	14,605	21,324
Capacity factors:			
CCGT facilities	67.8%	48.2%	—%
Coal facilities	63.2%	—%	63.3%
Weather - percent of normal (a):			
Cooling degree days	121.0%	118.0%	134.0%
Heating degree days	101.0%	102.0%	95.0%
Average Market On-Peak Power Prices ($/MWh) (b):			
PJM West	$ 41.79		
AD Hub	$ 40.47		
New York - Zone C		$ 37.03	
Mass Hub		$ 50.11	
Average natural gas price - TetcoM3 ($/MMBtu) (c)	$ 3.69		
Average natural gas price - Algonquin Citygates ($/MMBtu) (c)		$ 4.84	

(a) Reflects cooling degree days or heating degree days for the region based on Weather Services International (WSI) data. For the year ended December 31, 2018, represents April 9, 2018 through December 31, 2018 only.
(b) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized. For the year ended December 31, 2018, represents April 9, 2018 through December 31, 2018 only.
(c) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us. For the year ended December 31, 2018, represents April 9, 2018 through December 31, 2018 only.

Net income totaled $100 million, $79 million and $35 million and Adjusted EBITDA totaled $592 million, $293 million and $66 million in the year ended December 31, 2018, for PJM, NY/NE and MISO segments respectively.

	PJM	NY/NE	MISO
Generation revenue net of fuel	$ 481	$ 116	$ 229
Capacity revenue	369	260	61
Operating costs	(243)	(74)	(202)
Selling, general and administrative expenses	(52)	(37)	(52)
Equity income from unconsolidated investment and other	7	11	—
Other	30	17	30
Adjusted EBITDA	**$ 592**	**$ 293**	**$ 66**
Depreciation and amortization	(413)	(152)	(9)
Unrealized net gains (losses) on hedging activities	(42)	(40)	9
Purchase accounting impacts	1	(9)	(12)
Transition and merger expenses	(14)	(2)	(9)
Other	(24)	(11)	(10)
Net income	**$ 100**	**$ 79**	**$ 35**

Asset Closure Segment — Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

	Year Ended December 31, 2018	Year Ended December 31, 2017	Favorable (Unfavorable) Change
Operating revenues	$ 50	$ 964	$ (914)
Fuel, purchased power costs and delivery fees	(40)	(607)	567
Operating costs	(43)	(380)	337
Depreciation and amortization	—	(1)	1
Selling, general and administrative expenses	(17)	(19)	2
Impairment of long-lived assets	—	(25)	25
Operating income (loss)	(50)	(68)	18
Other income	2	6	(4)
Other deductions	(1)	(1)	—
Income (loss) before income taxes	(49)	(63)	14
Income tax expense	—	—	—
Net income (loss)	**$ (49)**	**$ (63)**	**$ 14**
Depreciation and amortization	—	1	(1)
EBITDA	(49)	(62)	13
Generation plant retirement expenses	—	206	(206)
Fresh start accounting impacts	1	14	(13)
Transition and merger expenses	2	—	2
Other	(3)	—	(3)
Adjusted EBITDA	**$ (49)**	**$ 158**	**$ (207)**
Production volumes (GWh)	1,159	25,392	(24,233)

Results for the Asset Closure segment reflect the retirement of the Stuart and Killen plants in May 2018 (acquired in the Merger), retirement of the Northeastern waste coal plant in October 2018 and the retirement of the Monticello, Sandow and Big Brown plants in January and February 2018 (see Note 4 to the Financial Statements) and corresponding 95% decrease in volume in the year ended December 31, 2018. Operating costs for the year ended December 31, 2018 included ongoing costs associated with closing these plants as well as a favorable adjustment to the estimated asset retirement obligation of $56 million.

Predecessor Consolidated Financial Results — Period from January 1, 2016 through October 2, 2016

	Predecessor Period from January 1, 2016 through October 2, 2016
Operating revenues	$ 3,973
Fuel, purchased power costs and delivery fees	(2,082)
Net gain from commodity hedging and trading activities	282
Operating costs	(664)
Depreciation and amortization	(459)
Selling, general and administrative expenses	(482)
Operating income (loss)	568
Other income	19
Other deductions	(75)
Interest expense and related charges	(1,049)
Reorganization items	22,121
Income (loss) before income taxes	21,584
Income tax benefit	1,267
Net income (loss)	$ 22,851

Predecessor Operating Statistics — Period from January 1, 2016 through October 2, 2016

	Predecessor
	Period from January 1, 2016 through October 2, 2016
Operating revenues:	
Retail electricity revenues	$ 3,154
Wholesale electricity revenues and other operating revenues (a)(b)	819
Total operating revenues	$ 3,973
Fuel, purchased power costs and delivery fees:	
Fuel for generation facilities and purchased power costs (a)	$ 950
Other costs	108
Delivery fees	1,024
Total	$ 2,082
Sales volumes (GWh):	
Retail electricity sales volumes	30,973
Wholesale electricity sales volumes (b)	25,563
Production volumes (GWh):	
Nuclear facilities	15,005
Lignite and coal facilities (c)	31,865
Natural gas facilities	8,539
Capacity factors:	
Nuclear facilities	99.2%
Lignite and coal facilities (c)	60.5%
CCGT facilities	65.2%
Market pricing:	
Average ERCOT North power price ($/MWh)	$ 20.78
Weather (North Texas average) - percent of normal (d):	
Cooling degree days	102.8%
Heating degree days	81.9%

(a) Upon settlement, physical derivative commodity contracts that we mark-to-market in net income, such as certain electricity sales and purchase agreements and coal purchase contracts, wholesale electricity revenues and fuel and purchased power costs are reported at approximated market prices, as required by accounting rules, rather than contract price. The offsetting differences between contract and market prices are reported in net gain from commodity hedging and trading activities.

(b) Includes net amounts related to sales and purchases of balancing energy in the ERCOT real-time market.

(c) Includes the estimated effects of economic backdown (including seasonal operations) of lignite/coal-fueled units totaling 14,420 GWh for the period from January 1, 2016 through October 2, 2016.

(d) Weather data is obtained from Weatherbank, Inc., an independent company that collects and archives weather data from reporting stations of the National Oceanic and Atmospheric Administration (a federal agency under the U.S. Department of Commerce). Normal is defined as the average over the 10-year period from 2000 to 2010.

Predecessor Financial Results — Period from January 1, 2016 through October 2, 2016

For the period from January 1, 2016 through October 2, 2016, income before income taxes totaled $21.584 billion and included a $24.252 billion gain on reorganization adjustments and a $2.013 billion loss for the net impacts from the adoption of fresh start reporting (see Notes 5 and 7 to the Financial Statements). Results also reflected the effect of declining average electricity prices on operating revenues, $977 million in adequate protection interest expense paid/accrued on pre-petition debt and $116 million in reorganization items associated with the Chapter 11 Cases.

Operating revenues totaled $3.973 billion for the period from January 1, 2016 through October 2, 2016. Retail electricity revenues totaled $3.154 billion and were negatively impacted by declining average prices and reduced volumes reflecting milder than normal weather in 2016. Wholesale revenues totaled $649 million and were positively impacted by increases in generation volumes (approximately 8,048 GWh) driven by the Lamar and Forney generation assets acquired in April 2016 (see Note 3 to the Financial Statements), partially offset by lower average wholesale electricity prices.

Following is an analysis of amounts reported as net losses from commodity hedging and trading activities. Results are primarily related to natural gas and power hedging activity.

	Predecessor
	Period from January 1, 2016 through October 2, 2016
Realized net gains	$ 320
Unrealized net gains (losses)	(38)
Total	$ 282

The negative impacts of declining average prices on wholesale operating revenues were partially offset by realized net gains reflecting settled gains on derivatives due to declining market prices. These gains were primarily related to natural gas positions.

For the period from January 1, 2016 through October 2, 2016, net unrealized losses were primarily impacted by reversals of previously recorded unrealized net gains on settled positions.

Fuel, purchased power costs and delivery fees totaled $2.082 billion for the period from January 1, 2016 through October 2, 2016 reflecting the impact of declining electricity prices on purchased power costs during 2016, partially offset by incremental natural gas fuel costs associated with the Lamar and Forney Acquisition.

Operating costs totaled $664 million for the period from January 1, 2016 through October 2, 2016 and primarily reflect maintenance expense for generation assets, including the scope and timing of maintenance costs at lignite/coal-fueled generation facilities. Operating costs were also impacted by incremental operation and maintenance costs associated with the Lamar and Forney Acquisition.

Depreciation and amortization expenses totaled $459 million for the period from January 1, 2016 through October 2, 2016 and primarily reflected depreciation on power generation and mining property, plant and equipment and amortization of identifiable intangible assets. Depreciation and amortization expenses were also impacted by incremental depreciation expense associated with the Lamar and Forney Acquisition.

SG&A expenses totaled $482 million for the period from January 1, 2016 through October 2, 2016 and reflected administrative and general salaries, employee benefits, marketing costs related to retail electricity activity and other administrative costs.

Results also include $32 million of severance expense, primarily reported in fuel, purchased power costs and delivery fees and operating costs, associated with certain actions taken to reduce costs related to mining and lignite/coal generation operations.

For the period from January 1, 2016 through October 2, 2016, interest expense and related charges totaled $1.049 billion and included adequate protection payments approved by the Bankruptcy Court for the benefit of TCEH secured creditors totaling $977 million and interest expense on debtor-in-possession financing totaling $76 million.

Energy-Related Commodity Contracts and Mark-to-Market Activities

The table below summarizes the changes in commodity contract assets and liabilities for the periods presented. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $380 million, $145 million, $166 million and $38 million in unrealized net losses for the Successor period for the year ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016, and the Predecessor period from January 1, 2016 through October 2, 2016, respectively, all arising from mark-to-market accounting for positions in the commodity contract portfolio.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
Commodity contract net asset (liability) at beginning of period	$ (96)	$ 64	$ 181	$ 271
Settlements/termination of positions (a)	457	(207)	(95)	(232)
Changes in fair value of positions in the portfolio (b)	(837)	62	(71)	194
Acquired commodity contracts in Merger (c)	(454)	—	—	—
Other activity (d)	80	(15)	49	(35)
Commodity contract net asset (liability) at end of period	$ (850)	$ (96)	$ 64	$ 198

(a) Represents reversals of previously recognized unrealized gains and losses upon settlement/termination (offsets realized gains and losses recognized in the settlement period). The years ended December 31, 2018 and 2017 include reversals of $17 million and $63 million, respectively of previously recorded unrealized gains related to Vistra Energy beginning balances. The year ended December 31, 2018 also includes reversal of $320 million of previously recorded unrealized losses related to commodity contracts acquired in the Merger. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.
(b) Represents unrealized net gains (losses) recognized, reflecting the effect of changes in fair value. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.
(c) Includes fair value of commodity contracts acquired at the Merger Date (see Note 2 to the Financial Statements).
(d) Represents changes in fair value of positions due to receipt or payment of cash not reflected in unrealized gains or losses. Amounts are generally related to premiums related to options purchased or sold as well as certain margin deposits classified as settlement for certain transactions executed on the CME.

Maturity Table — The following table presents the net commodity contract liability arising from recognition of fair values at December 31, 2018, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

	Successor				
	Maturity dates of unrealized commodity contract net liability at December 31, 2018				
Source of fair value	**Less than 1 year**	**1-3 years**	**4-5 years**	**Excess of 5 years**	**Total**
Prices actively quoted	$ (106)	$ 5	$ —	$ —	$ (101)
Prices provided by other external sources	(507)	(107)	—	—	(614)
Prices based on models	(59)	(64)	(12)	—	(135)
Total	$ (672)	$ (166)	$ (12)	$ —	$ (850)

FINANCIAL CONDITION

Operating Cash Flows

Successor — *Year Ended December 31, 2018 Compared to Year Ended December 31, 2017* — Cash provided by operating activities totaled $1.471 billion and $1.386 billion in the years ended December 31, 2018 and 2017, respectively. The favorable change of $85 million was primarily driven by increased cash from operations reflecting operations acquired in the Merger largely offset by increased interest paid of $406 million due to the assumption of long-term debt obligations in the Merger, an increase in cash used for margin deposits of $367 million related to derivative contracts and $238 million in proceeds received in 2017 from the Alcoa contract settlement.

Period from October 3, 2016 through December 31, 2016 — Cash provided by operating activities totaled $81 million and was primarily driven by cash earnings from our business of approximately $251 million after taking into consideration depreciation and amortization and unrealized mark-to-market losses on derivatives, offset by a net use of cash of approximately $170 million in working capital primarily driven by cash utilized in margin postings related to derivative contracts.

Depreciation and Amortization — Depreciation and amortization expense reported as a reconciling adjustment in the statements of consolidated cash flows exceeds the amount reported in the statements of consolidated income (loss) by $139 million, $136 million and $69 million for the year ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016, respectively. The difference represented amortization of nuclear fuel, which is reported as fuel costs in the statements of consolidated income (loss) consistent with industry practice, and amortization of intangible net assets and liabilities that are reported in various other statements of consolidated income (loss) line items including operating revenues and fuel and purchased power costs and delivery fees.

Predecessor — *Period from January 1, 2016 through October 2, 2016* — Cash used in operating activities totaled $238 million and was primarily driven by cash used for margin deposit postings and other working capital utilization.

Financing Cash Flows

Successor — *Year Ended December 31, 2018* — Cash used in financing activities totaled $2.723 billion and reflected:

- cash tender offers to purchase $1.542 billion of senior notes assumed in the Merger;
- the amendment to the Vistra Operations Credit Facilities, including the repayment of $500 million in borrowings under the Term C Facility;
- the redemption of $850 million principal amount of outstanding 6.75% Senior Notes in May 2018;
- the repurchases of $119 million principal amount of outstanding Vistra Energy senior notes in November and December 2018;
- premium amounts paid in connection with the debt tender offer and other debt financing fees totaling $236 million, and
- $763 million of cash paid for share repurchases during 2018,

partially offset by:

- the issuance of $1.0 billion principal amount of Vistra Operations 5.500% senior notes due 2026, and
- proceeds of $339 million from the accounts receivable securitization program.

Year Ended December 31, 2017 — Cash used in financing activities totaled $201 million and reflected the repayment of debt, including the repayment of $150 million in principal under the Term Loan C Facility (see Note 14 to the Financial Statements).

Period from October 3, 2016 through December 31, 2016 — Cash provided by financing activities totaled $6 million and related to the net impacts of the Incremental Term Loan B borrowings and the Special Dividend paid to shareholders.

Predecessor — *Period from January 1, 2016 through October 2, 2016* — Cash provided by financing activities totaled $1.059 billion and primarily reflected $2.040 billion in net borrowings under the DIP Roll Facilities and the DIP Facility, including $870 million in net borrowings to fund the Lamar and Forney Acquisition (see Note 3 to the Financial Statements), and $69 million from the issuance of preferred stock, partially offset by $915 million in payments to extinguish claims under the Plan of Reorganization and $112 million in fees related to the issuance of the DIP Roll Facilities.

Investing Cash Flows

Successor *— Year Ended December 31, 2018 —* Cash used in investing activities totaled $101 million and reflected capital expenditures (including LTSA prepayments and nuclear fuel purchases) totaling $496 million and development and growth expenditures totaling $34 million, partially offset by $445 million of cash acquired in the Merger.

Capital expenditures, including nuclear fuel, in the year ended December 31, 2018 totaled $496 million and consisted of:

- $208 million primarily for our generation and mining operations;
- $118 million for nuclear fuel purchases;
- $70 million for information technology, other corporate investments and Comanche Peak repairs, and
- $100 million for LTSA prepayments.

Year Ended December 31, 2017 — Cash used in investing activities totaled $727 million and was primarily driven by payments of $355 million related to the Odessa Acquisition, Upton 2 solar development expenditures totaling $190 million and capital expenditures (including nuclear fuel purchases) totaling $176 million. The Odessa Acquisition and the Upton 2 solar development were funded using cash on hand.

Capital expenditures, including nuclear fuel, in the year ended December 31, 2017 totaled $176 million and consisted of:

- $88 million primarily for our generation and mining operations;
- $62 million for nuclear fuel purchases, and
- $26 million for information technology and other corporate investments.

Period from October 3, 2016 through December 31, 2016 — Cash used in investing activities totaled $93 million and was primarily driven by capital expenditures (including nuclear fuel purchases) totaling $89 million.

Capital expenditures, including nuclear fuel, in the period from October 3, 2016 through December 31, 2016 totaled $89 million and consisted of:

- $40 million primarily for our generation and mining operations;
- $41 million for nuclear fuel purchases, and
- $8 million for information technology and other corporate investments.

Predecessor *— Period from January 1, 2016 through October 2, 2016* — Cash used in investing activities totaled $1.420 billion and was primarily driven by payments of $1.343 billion related to the Lamar and Forney Acquisition net of cash acquired (see Note 3 to the Financial Statements) and capital expenditures (including nuclear fuel purchases) totaling $263 million.

Capital expenditures, including nuclear fuel, in the period from January 1, 2016 through October 2, 2016 totaled $263 million and consisted of:

- $211 million primarily for our generation and mining operations;
- $33 million for nuclear fuel purchases, and
- $19 million for information technology and other corporate investments.

Debt Activity

See Note 14 to the Financial Statements for details of the Vistra Operations Credit Facilities and other long-term debt.

Available Liquidity

The following table summarizes changes in available liquidity for the year ended December 31, 2018:

	December 31, 2018	December 31, 2017	Change
Cash and cash equivalents (a)	$ 636	$ 1,487	$ (851)
Vistra Operations Credit Facilities — Revolving Credit Facility	1,135	834	301
Vistra Operations Credit Facilities — Term Loan C Facility (b)	—	7	(7)
Total available liquidity	$ 1,771	$ 2,328	$ (557)

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(a) Cash and cash equivalents excludes $500 million of restricted cash held for letter of credit support at December 31, 2017 (see Note 23 to the Financial Statements).

(b) The Term Loan C Facility was used for issuing letters of credit for general corporate purposes. Borrowings totaling $500 million were held in collateral accounts at December 31, 2017, and were reported as restricted cash in our consolidated balance sheets. In June 2018, the Vistra Operations Credit Facilities were amended, and the Term Loan C Facility was repaid using $500 million of cash from the collateral accounts used to backstop letters of credit.

The decrease in available liquidity of $557 million in the year ended December 31, 2018 was primarily driven by cash tender offers to purchase $1.542 billion of senior notes assumed in the Merger, the redemption of $850 million principal amount of outstanding 6.75% senior notes, the amendment to the Vistra Operations Credit Facilities, the repurchases of $119 million principal amount of outstanding Vistra Energy senior notes and $763 million in cash paid for share repurchases, partially offset by the issuance of $1.0 billion principal amount of Vistra Operations 5.500% senior notes, $445 million of cash acquired in the Merger, increased available capacity under the Revolving Credit Facility and proceeds of $339 million from the accounts receivable securitization program.

Based upon our current internal financial forecasts, we believe that we will have sufficient liquidity to fund our anticipated cash requirements, including those related to our capital allocation initiatives, through at least the next 12 months. Our operational cash flows tend to be seasonal and weighted toward the second half of the year.

Capital Expenditures

Estimated capital expenditures and nuclear fuel purchases for 2019 are expected to total approximately $629 million and include:

- $432 million for investments in generation and mining facilities;
- $74 million for nuclear fuel purchases;
- $80 million for information technology and other corporate investments, and
- $43 million for growth and development.

Liquidity Effects of Commodity Hedging and Trading Activities

We have entered into commodity hedging and trading transactions that require us to post collateral if the forward price of the underlying commodity moves such that the hedging or trading instrument we hold has declined in value. We use cash, letters of credit and other forms of credit support to satisfy such collateral posting obligations. See Note 14 to the Financial Statements for discussion of the Vistra Operations Credit Facilities.

Exchange cleared transactions typically require initial margin (*i.e.*, the upfront cash and/or letter of credit posted to take into account the size and maturity of the positions and credit quality) in addition to variation margin (*i.e.*, the daily cash margin posted to take into account changes in the value of the underlying commodity). The amount of initial margin required is generally defined by exchange rules. Clearing agents, however, typically have the right to request additional initial margin based on various factors, including market depth, volatility and credit quality, which may be in the form of cash, letters of credit, a guaranty or other forms as negotiated with the clearing agent. Cash collateral received from counterparties is either used for working capital and other business purposes, including reducing borrowings under credit facilities, or is required to be deposited in a separate account and restricted from being used for working capital and other corporate purposes. With respect to over-the-counter transactions, counterparties generally have the right to substitute letters of credit for such cash collateral. In such event, the cash collateral previously posted would be returned to such counterparties, which would reduce liquidity in the event the cash was not restricted.

At December 31, 2018, we received or posted cash and letters of credit for commodity hedging and trading activities as follows:

- $361 million in cash has been posted with counterparties as compared to $30 million posted at December 31, 2017;
- $4 million in cash has been received from counterparties as compared to $4 million received at December 31, 2017;
- $1.185 billion in letters of credit have been posted with counterparties as compared to $390 million posted at December 31, 2017, and
- $12 million in letters of credit have been received from counterparties as compared to $3 million received at December 31, 2017.

Income Tax Payments

In the next 12 months, we do not expect to make federal income tax payments due to Vistra Energy's forecasted loss position. In February 2019, we received a refund of $21 million related to Vistra Energy's 2017 federal tax return. We expect to make state income tax payments of approximately $30 million in the next 12 months. For the year ended December 31, 2018, federal income tax payments totaled $45 million, state income tax payments totaled $22 million and TRA payments totaled $16 million.

Capitalization

Our capitalization ratios consisted of 58% and 41% long-term debt (less amounts due currently) and 42% and 59% shareholders' equity at December 31, 2018 and 2017, respectively. Total long-term debt (including amounts due currently) to capitalization was 58% and 41% at December 31, 2018 and 2017, respectively.

Financial Covenants

The Credit Facilities Agreement includes a covenant, solely with respect to the Revolving Credit Facility and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and issued revolving letters of credit (in excess of $300 million) exceed 30% of the revolving commitments), that requires the consolidated first lien net leverage ratio not exceed 4.25 to 1.00. As of December 31, 2018, we were in compliance with this financial covenant.

See Note 14 to the Financial Statements for discussion of other covenants related to the Vistra Operations Credit Facilities.

Collateral Support Obligations

The RCT has rules in place to assure that parties can meet their mining reclamation obligations. In September 2016, the RCT agreed to a collateral bond of up to $975 million to support Luminant's reclamation obligations. The collateral bond is effectively a first lien on all of Vistra Operations' assets (which ranks pari passu with the Vistra Operations Credit Facilities) that contractually enables the RCT to be paid (up to $975 million) before the other first lien lenders in the event of a liquidation of our assets. Collateral support relates to land mined or being mined and not yet reclaimed as well as land for which permits have been obtained but mining activities have not yet begun and land already reclaimed but not released from regulatory obligations by the RCT, and includes cost contingency amounts.

The PUCT has rules in place to assure adequate creditworthiness of each REP, including the ability to return customer deposits, if necessary. Under these rules, at December 31, 2018, Vistra Energy has posted letters of credit in the amount of $55 million with the PUCT, which is subject to adjustments.

The RTOs/ISOs we operate in have rules in place to assure adequate creditworthiness of parties that participate in the markets operated by those RTOs/ISOs. Under these rules, Vistra Energy has posted collateral support totaling $181 million in the form of letters of credit, $10 million in the form of a surety bond and $1 million in cash at December 31, 2018 (which is subject to daily adjustments based on settlement activity with the RTOs/ISOs).

Material Cross Default/Acceleration Provisions

Certain of our contractual arrangements contain provisions that could result in an event of default if there was a failure under financing arrangements to meet payment terms or to observe covenants that could result in an acceleration of payments due. Such provisions are referred to as "cross default" or "cross acceleration" provisions.

A default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of $300 million may result in a cross default under the Vistra Operations Credit Facilities. Such a default would allow the lenders to accelerate the maturity of outstanding balances (approximately $5.8 billion at December 31, 2018) under such facilities.

Each of Vistra Operations' (or its subsidiaries') commodity hedging agreements and interest rate swap agreements that are secured with a lien on its assets on a pari passu basis with the Vistra Operations Credit Facilities lenders contains a cross default provision. An event of a default by Vistra Operations or any of its subsidiaries relating to indebtedness in excess of $300 million that results in the acceleration of such debt, would give each counterparty under these hedging agreements the right to terminate its hedge or interest rate swap agreement with Vistra Operations (or its applicable subsidiary) and require all outstanding obligations under such agreement to be settled.

Under Vistra Operations' senior notes indenture, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any subsidiary guarantor for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $300 million or more, may result in a cross default under the senior notes.

Each of Vistra Energy's indentures for each series of senior notes (except with respect to the Consent Senior Notes) and the TEUs, respectively, contain a cross default provision. A default by Vistra Energy, as issuer of each series of senior notes and the TEUs, respectively, in respect of certain specified indebtedness in an aggregate amount in excess of $100 million may result in a cross default under the respective indentures of the senior notes and TEUs. Such a default would allow the trustee or noteholders holding at least 25% in principal amount of the respective series of senior notes or TEUs that are outstanding (each such series treated as a separate class) to accelerate the maturity of such portion of the principal amount of all securities of such series of senior notes or TEUs, respectively.

Additionally, we enter into energy-related physical and financial contracts, the master forms of which contain provisions whereby an event of default or acceleration of settlement would occur if we were to default under an obligation in respect of borrowings in excess of thresholds, which may vary by contract.

The Receivables Program contains a cross default provision. The cross default provision applies, among other instances, if Vistra Operations, the performance guarantor, fails to make a payment of principal or interest on any indebtedness that is outstanding in a principal amount of at least $300 million, or, in the case of TXU Energy, the originator and servicer, in a principal amount of at least $50 million, or if other events occur or circumstances exist under such indebtedness which give rise to a right of the debtholder to accelerate such indebtedness, or if such indebtedness becomes due before its stated maturity. If this cross default provision is triggered, a termination event under the Receivables Facility would occur and the Receivables Facility may be terminated.

Under the Vistra Operations' alternative letter of credit program, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any subsidiary guarantor for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $300 million or more, may result in a termination of the facility.

Contractual Obligations and Commitments

The following table summarizes the amounts and related maturities of our contractual cash obligations at December 31, 2018. See Notes 14 and 15 to the Financial Statements for additional disclosures regarding debts and noncancellable purchase obligations.

Contractual Cash Obligations:	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years	Total
Debt – principal, including capital leases (a)	$ 191	$ 334	$ 5,932	$ 4,453	$ 10,910
Debt – interest	611	1,207	990	474	3,282
Operating leases	35	54	39	168	296
Long-term service and maintenance contracts	175	316	316	2,619	3,426
Obligations under commodity purchase and services agreements (b)	1,589	912	460	709	3,670
Total contractual cash obligations	$ 2,601	$ 2,823	$ 7,737	$ 8,423	$ 21,584

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(a) Includes $5.813 billion of borrowings under the Vistra Operations Credit Facility, $3.626 billion principal amount of Vistra Energy senior notes, $1.0 billion principal amount of Vistra Operations senior notes and $471 million principal amount of long-term debt, including forward capacity agreements, equipment financing agreements and mandatorily redeemable preferred stock. Excludes unamortized premiums, discounts and debt costs.

(b) Includes capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear related outsourcing and other purchase commitments. Amounts presented for variable priced contracts reflect the year-end 2018 price for all periods except where contractual price adjustment or index-based prices are specified.

The following are not included in the table above:

- the TRA obligation (see Note 10 to the Financial Statements);
- asset retirement obligations (see Note 23 to the Financial Statements);
- arrangements between affiliated entities and intercompany debt (see Note 21 to the Financial Statements);
- individual contracts that have an annual cash requirement of less than $1 million (however, multiple contracts with one counterparty that are more than $1 million on an aggregated basis have been included);
- contracts that are cancellable without payment of a substantial cancellation penalty, and
- employment contracts with management.

Guarantees

See Note 15 to the Financial Statements for discussion of guarantees.

OFF–BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements.

COMMITMENTS AND CONTINGENCIES

See Note 15 to the Financial Statements for discussion of commitments and contingencies.

CHANGES IN ACCOUNTING STANDARDS

See Note 1 to the Financial Statements for discussion of changes in accounting standards.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that in the normal course of business we may experience a loss in value due to changes in market conditions that affect economic factors such as commodity prices, interest rates and counterparty credit. Our exposure to market risk is affected by several factors, including the size, duration and composition of our energy and financial portfolio, as well as the volatility and liquidity of markets. Instruments used to manage this exposure include interest rate swaps to hedge debt costs, as well as exchange-traded, over-the-counter contracts and other contractual arrangements to hedge commodity prices.

Risk Oversight

We manage the commodity price, counterparty credit and commodity-related operational risk related to the competitive energy business within limitations established by senior management and in accordance with overall risk management policies. Interest rate risk is managed centrally by our treasury function. Market risks are monitored by risk management groups that operate independently of the wholesale commercial operations, utilizing defined practices and analytical methodologies. These techniques measure the risk of change in value of the portfolio of contracts and the hypothetical effect on this value from changes in market conditions and include, but are not limited to, position reporting and review, Value at Risk (VaR) methodologies and stress test scenarios. Key risk control activities include, but are not limited to, transaction review and approval (including credit review), operational and market risk measurement, transaction authority oversight, validation of transaction capture, market price validation and reporting, and portfolio valuation and reporting, including mark-to-market valuation, VaR and other risk measurement metrics.

Vistra Energy has a risk management organization that enforces applicable risk limits, including the respective policies and procedures to ensure compliance with such limits, and evaluates the risks inherent in our businesses.

Commodity Price Risk

Our business is subject to the inherent risks of market fluctuations in the price of electricity, natural gas and other energy-related products it markets or purchases. We actively manage the portfolio of generation assets, fuel supply and retail sales load to mitigate the near-term impacts of these risks on results of operations. Similar to other participants in the market, we cannot fully manage the long-term value impact of structural declines or increases in natural gas and power prices.

In managing energy price risk, we enter into a variety of market transactions including, but not limited to, short- and long-term contracts for physical delivery, exchange-traded and over-the-counter financial contracts and bilateral contracts with customers. Activities include hedging, the structuring of long-term contractual arrangements and proprietary trading. We continuously monitor the valuation of identified risks and adjust positions based on current market conditions. We strive to use consistent assumptions regarding forward market price curves in evaluating and recording the effects of commodity price risk.

VaR Methodology — A VaR methodology is used to measure the amount of market risk that exists within the portfolio under a variety of market conditions. The resultant VaR produces an estimate of a portfolio's potential for loss given a specified confidence level and considers, among other things, market movements utilizing standard statistical techniques given historical and projected market prices and volatilities.

Parametric processes are used to calculate VaR and are considered by management to be the most effective way to estimate changes in a portfolio's value based on assumed market conditions for liquid markets. The use of this method requires a number of key assumptions, such as use of (i) an assumed confidence level; (ii) an assumed holding period (*i.e.*, the time necessary for management action, such as to liquidate positions), and (iii) historical estimates of volatility and correlation data. The table below details a VaR measure related to various portfolios of contracts.

VaR for Underlying Generation Assets and Energy-Related Contracts — This measurement estimates the potential loss in value, due to changes in market conditions, of all underlying generation assets and contracts, based on a 95% confidence level and an assumed holding period of 60 days for a forward period through December 2019.

	Year Ended December 31,	
	2018	2017
Month-end average VaR	$ 182	$ 92
Month-end high VaR	$ 267	$ 140
Month-end low VaR	$ 65	$ 62

The increase in the month-end high VaR risk measure in 2018 reflects operations acquired in the Merger.

Interest Rate Risk

The following table provides information concerning our financial instruments at December 31, 2018 and 2017 that are sensitive to changes in interest rates. Debt amounts consist of the Vistra Operations Credit Facilities. See Note 14 to the Financial Statements for further discussion of these financial instruments.

	Expected Maturity Date (millions of dollars, except percentages)									
	2019	2020	2021	2022	2023	There-after	2018 Total Carrying Amount	2018 Total Fair Value	2017 Total Carrying Amount	2017 Total Fair Value
Long-term debt, including current maturities (a):										
Variable rate debt amount	$ 59	$ 59	$ 59	$ 59	$ 3,640	$ 1,937	$ 5,813	$ 5,599	$4,311	$ 4,334
Average interest rate (b)	4.55%	4.55%	4.55%	4.55%	4.59%	4.47%	4.55%		3.98%	
Debt swapped to fixed (c):										
Notional amount	$ 159	$ 358	$ —	$ —	$ 3,000	$ 4,200	$ 7,717		$3,000	
Average pay rate	4.16%	4.10%	4.07%	4.07%	4.34%	5.01%	4.38%		4.59%	
Average receive rate	4.56%	4.57%	4.57%	4.57%	4.53%	4.45%	4.53%		4.11%	

(a) Unamortized premiums, discounts and debt issuance costs are excluded from the table.
(b) The weighted average interest rate presented is based on the rates in effect at December 31, 2018.
(c) Interest rate swaps have maturity dates through July 2026.

At December 31, 2018, the potential reduction of annual pretax earnings over the next twelve months due to a one percentage-point (100 basis points) increase in floating interest rates on long-term debt totaled approximately $14 million, taking into account the interest rate swaps discussed in Note 14 to Financial Statements.

Credit Risk

Credit risk relates to the risk of loss associated with nonperformance by counterparties. We minimize credit risk by evaluating potential counterparties, monitoring ongoing counterparty risk and assessing overall portfolio risk. This includes review of counterparty financial condition, current and potential credit exposures, credit rating and other quantitative and qualitative credit criteria. We also employ certain risk mitigation practices, including utilization of standardized master agreements that provide for netting and setoff rights, as well as credit enhancements such as margin deposits and customer deposits, letters of credit, parental guarantees and surety bonds. See Note 18 to the Financial Statements for further discussion of this exposure.

Bankruptcies — We are party to (i) certain gas transportation agreements with Pacific Gas and Electric Corporation (PG&E) and (ii) in connection with the Moss Landing battery storage project, we entered into a long-term renewable power purchase agreement with PG&E, which was approved by the California Public Utilities Commission in November 2018. PG&E filed for Chapter 11 bankruptcy protection in January 2019.

As of December 31, 2018, we had no outstanding accounts receivable from PG&E and accordingly, we have not recorded a reserve related to the pre-petition receivables. While our assumptions and conclusions may change, we could have future impairment losses, or specifically with respect to the gas transportation agreements, be required to seek alternative, higher-cost fuel transportation methods, if any of the terms of the contracts are not honored by PG&E or the contracts are rejected through the bankruptcy process.

Credit Exposure — Our gross credit exposure (excluding collateral impacts) associated with retail and wholesale trade accounts receivable and net derivative assets arising from commodity contracts and hedging and trading activities totaled $975 million at December 31, 2018.

At December 31, 2018, Retail segment credit exposure totaled $683 million, including $676 million of trade accounts receivable and $7 million related to derivative assets. Cash deposits and letters of credit held as collateral for these receivables totaled $38 million, resulting in a net exposure of $645 million. We believe the risk of material loss (after consideration of bad debt allowances) from nonperformance by these customers is unlikely based upon historical experience. Allowances for uncollectible accounts receivable are established for the potential loss from nonpayment by these customers based on historical experience, market or operational conditions and changes in the financial condition of large business customers.

At December 31, 2018, aggregate ERCOT, PJM, NY/NE and MISO segments credit exposure totaled $292 million including $147 million related to derivative assets and $145 million of trade accounts receivable, after taking into account master netting agreement provisions but excluding collateral impacts.

Including collateral posted to us by counterparties, our net ERCOT, PJM, NY/NE and MISO segments exposure was $281 million, substantially all of which is with investment grade customers as seen in the following table that presents the distribution of credit exposure at December 31, 2018. Credit collateral includes cash and letters of credit, but excludes other credit enhancements such as guarantees or liens on assets.

	Exposure Before Credit Collateral	Credit Collateral	Net Exposure
Investment grade	$ 247	$ —	$ 247
Below investment grade or no rating	45	11	34
Totals	$ 292	$ 11	$ 281

Significant (10% or greater) concentration of credit exposure exists with four counterparties, which represented an aggregate $195 million, or 70%, of the total net exposure. We view exposure to these counterparties to be within an acceptable level of risk tolerance due to the counterparties' credit ratings, each of which is rated as investment grade, the counterparties' market role and deemed creditworthiness and the importance of our business relationship with the counterparties. An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts such as margin deposits are owed to the counterparties or delays in receipts of expected settlements owed to us.

Contracts classified as "normal" purchase or sale and non-derivative contractual commitments are not marked-to-market in the financial statements and are excluded from the detail above. Such contractual commitments may contain pricing that is favorable considering current market conditions and therefore represent economic risk if the counterparties do not perform.

At December 31, 2018, interest rate swap exposure in the Corporate and Other non-segment totaled $51 million. There are no collateral offsets. The counterparty credit rating is investment grade.

FORWARD-LOOKING STATEMENTS

This report and other presentations made by us contain "forward-looking statements." All statements, other than statements of historical facts, that are included in this report, or made in presentations, in response to questions or otherwise, that address activities, events or developments that may occur in the future, including (without limitation) such matters as activities related to our financial or operational projections, capital allocation, capital expenditures, liquidity, dividend policy, business strategy, competitive strengths, goals, future acquisitions or dispositions, development or operation of power generation assets, market and industry developments and the growth of our businesses and operations (often, but not always, through the use of words or phrases such as "intends," "plans," "will likely," "unlikely," "expected," "anticipated," "estimated," "should," "may," "projection," "target," "goal," "objective" and "outlook"), are forward-looking statements. Although we believe that in making any such forward-looking statement our expectations are based on reasonable assumptions, any such forward-looking statement involves uncertainties and risks and is qualified in its entirety by reference to the discussion under Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* in this report and the following important factors, among others, that could cause our actual results to differ materially from those projected in or implied by such forward-looking statements:

- the actions and decisions of judicial and regulatory authorities;
- prohibitions and other restrictions on our operations due to the terms of our agreements;
- prevailing federal, state and local governmental policies and regulatory actions, including those of the legislatures and other government actions of states in which we operate, the U.S. Congress, the FERC, the NERC, the TRE, the public utility commissions of states and locales in which we operate, CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, the RCT, the NRC, the EPA, the environmental regulatory bodies of states in which we operate, the MSHA and the CFTC, with respect to, among other things:
  - allowed prices;
  - industry, market and rate structure;
  - purchased power and recovery of investments;
  - operations of nuclear generation facilities;
  - operations of fossil-fueled generation facilities;
  - operations of mines;
  - acquisition and disposal of assets and facilities;
  - development, construction and operation of facilities;
  - decommissioning costs;
  - present or prospective wholesale and retail competition;
  - changes in federal, state and local tax laws, rates and policies, including additional regulation, interpretations, amendments, or technical corrections to the TCJA;
  - changes in and compliance with environmental and safety laws and policies, including National Ambient Air Quality Standards, the Cross-State Air Pollution Rule, the Mercury and Air Toxics Standard, regional haze program implementation and GHG and other climate change initiatives, and
  - clearing over-the-counter derivatives through exchanges and posting of cash collateral therewith;
- expectations regarding, or impacts of, environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations that we are, or could become, subject to, which could increase our costs, result in an impairment of our assets, cause us to limit or terminate the operation of certain of our facilities, or otherwise have a negative financial effect;
- legal and administrative proceedings and settlements;
- general industry trends;
- economic conditions, including the impact of an economic downturn;
- weather conditions, including drought and limitations on access to water, and other natural phenomena, and acts of sabotage, wars or terrorist or cybersecurity threats or activities;
- our ability to collect trade receivables from counterparties;
- our ability to attract and retain profitable customers;
- our ability to profitably serve our customers;
- restrictions on competitive retail pricing;
- changes in wholesale electricity prices or energy commodity prices, including the price of natural gas;
- changes in prices of transportation of natural gas, coal, fuel oil and other refined products;
- sufficiency of, access to, and costs associated with coal, fuel oil, and natural gas inventories and transportation and storage thereof;
- changes in the ability of vendors to provide or deliver commodities as needed;

- beliefs and assumptions about the benefits of state- or federal-based subsidies to our market competition, and the corresponding impacts on us, including if such subsidies are disproportionately available to our competitors;
- the effects of, or changes to, market design and the power and capacity procurement processes in the markets in which we operate;
- changes in market heat rates in the CAISO, ERCOT, ISO-NE, MISO, NYISO and PJM electricity markets;
- our ability to effectively hedge against unfavorable commodity prices, including the price of natural gas, market heat rates and interest rates;
- population growth or decline, or changes in market supply or demand and demographic patterns, particularly in ERCOT, MISO and PJM;
- our ability to mitigate forced outage risk, including managing risk associated with CP in PJM and performance incentives in ISO-NE;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;
- access to adequate transmission facilities to meet changing demands;
- changes in interest rates, commodity prices, rates of inflation or foreign exchange rates;
- changes in operating expenses, liquidity needs and capital expenditures;
- commercial bank market and capital market conditions and the potential impact of disruptions in U.S. and international credit markets;
- access to capital, the attractiveness of the cost and other terms of such capital and the success of financing and refinancing efforts, including availability of funds in capital markets;
- our ability to maintain prudent financial leverage;
- our ability to generate sufficient cash flow to make principal and interest payments in respect of, or refinance, our debt obligations;
- our ability to implement our growth strategy, including the completion and integration of mergers, acquisitions and/or joint venture activity and identification and completion of sales and divestitures activity;
- competition for new energy development and other business opportunities;
- inability of various counterparties to meet their obligations with respect to our financial instruments;
- counterparties' collateral demands and other factors affecting our liquidity position and financial condition;
- changes in technology (including large scale electricity storage) used by and services offered by us;
- changes in electricity transmission that allow additional power generation to compete with our generation assets;
- our ability to attract and retain qualified employees;
- significant changes in our relationship with our employees, including the availability of qualified personnel, and the potential adverse effects if labor disputes or grievances were to occur;
- changes in assumptions used to estimate costs of providing employee benefits, including medical and dental benefits, pension and OPEB, and future funding requirements related thereto, including joint and several liability exposure under ERISA;
- hazards customary to the industry and the possibility that we may not have adequate insurance to cover losses resulting from such hazards;
- the impact of our obligations under the TRA;
- our ability to optimize our assets through targeted investment in cost-effective technology enhancements and operations performance initiatives;
- our ability to effectively and efficiently plan, prepare for and execute expected asset retirements and reclamation obligations and the impacts thereof;
- our ability to successfully complete the integration of the businesses of Vistra Energy and Dynegy and our ability to successfully capture the full amount of projected synergies relating to the Merger, and
- actions by credit rating agencies.

Any forward-looking statement speaks only at the date on which it is made, and except as may be required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events or circumstances. New factors emerge from time to time, and it is not possible for us to predict them. In addition, we may be unable to assess the impact of any such event or condition or the extent to which any such event or condition, or combination of events or conditions, may cause results to differ materially from those contained in or implied by any forward-looking statement. As such, you should not unduly rely on such forward-looking statements.

INDUSTRY AND MARKET INFORMATION

Certain industry and market data and other statistical information used throughout this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources, including certain data published by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, the environmental regulatory bodies of states in which we operate and NYMEX. We did not commission any of these publications, reports or other sources. Some data is also based on good faith estimates, which are derived from our review of internal surveys, as well as the independent sources listed above. Industry publications, reports and other sources generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While we believe that each of these studies, publications, reports and other sources is reliable, we have not independently investigated or verified the information contained or referred to therein and make no representation as to the accuracy or completeness of such information. Forecasts are particularly likely to be inaccurate, especially over long periods of time, and we do not know what assumptions were used in preparing such forecasts. Statements regarding industry and market data and other statistical information used throughout this report involve risks and uncertainties and are subject to change based on various factors.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Vistra Energy Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vistra Energy Corp. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related statements of consolidated income (loss), consolidated comprehensive income (loss), consolidated cash flows, and consolidated equity, for the years ended December 31, 2018 and 2017, for the period October 3, 2016 through December 31, 2016 (Successor Company operations) and the period January 1, 2016 through October 2, 2016 (Predecessor Company operations), and the related notes (collectively referred to as the "financial statements"). In our opinion, the Successor Company financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows, for the years ended December 31, 2018 and 2017 and for the period October 3, 2016 through December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Further, in our opinion, the Predecessor Company financial statements present fairly, in all material respects, the results of operations and cash flows of the Predecessor Company for the period January 1, 2016 through October 2, 2016, in conformity with accounting principles generally accepted in the United States of America.

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

Fresh-Start Reporting

As discussed in Note 6 to the financial statements, on August 29, 2016 the Bankruptcy Court entered an order confirming the plan of reorganization which became effective on October 3, 2016. Accordingly, the accompanying financial statements have been prepared in conformity with Accounting Standards Codification Topic 852, *Reorganizations,* for the Successor Company as a new entity with assets, liabilities, and a capital structure having carrying values not comparable with prior periods as described in Note 1 to the financial statements.

Basis for Opinion

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

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

/s/ Deloitte & Touche LLP

Dallas, TX
February 28, 2019

We have served as the Company's auditor since 2002.

VISTRA ENERGY CORP.
STATEMENTS OF CONSOLIDATED INCOME (LOSS)
(Millions of Dollars, Except Per Share Amounts)

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Operating revenues	$ 9,144	$ 5,430	$ 1,191	$ 3,973
Fuel, purchased power costs and delivery fees	(5,036)	(2,935)	(720)	(2,082)
Net gain from commodity hedging and trading activities	—	—	—	282
Operating costs	(1,297)	(973)	(208)	(664)
Depreciation and amortization	(1,394)	(699)	(216)	(459)
Selling, general and administrative expenses	(926)	(600)	(208)	(482)
Impairment of long-lived assets	—	(25)	—	—
Operating income (loss)	491	198	(161)	568
Other income (Note 23)	47	37	10	19
Other deductions (Note 23)	(5)	(5)	—	(75)
Interest expense and related charges (Note 11)	(572)	(193)	(60)	(1,049)
Impacts of Tax Receivable Agreement (Note 10)	(79)	213	(22)	—
Equity in earnings of unconsolidated investment (Note 23)	17	—	—	—
Reorganization items (Note 5)	—	—	—	22,121
Income (loss) before income taxes	(101)	250	(233)	21,584
Income tax (expense) benefit (Note 9)	45	(504)	70	1,267
Net income (loss)	(56)	(254)	(163)	22,851
Less: Net loss attributable to noncontrolling interest	2	—	—	
Net loss attributable to Vistra Energy	$ (54)	$ (254)	$ (163)	
Weighted average shares of common stock outstanding:				
Basic	504,954,371	427,761,460	427,560,620	
Diluted	504,954,371	427,761,460	427,560,620	
Net loss per weighted average share of common stock outstanding:				
Basic	$ (0.11)	$ (0.59)	$ (0.38)	
Diluted	$ (0.11)	$ (0.59)	$ (0.38)	
Dividend declared per share of common stock	$ —	$ —	$ 2.32	

See Notes to the Consolidated Financial Statements.

VISTRA ENERGY CORP.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)
(Millions of Dollars)

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Net income (loss)	$ (56)	$ (254)	$ (163)	$ 22,851
Other comprehensive income (loss), net of tax effects:				
Effects related to pension and other retirement benefit obligations (net of tax (benefit) expense of $(2), $(6), $3 and $—)	(6)	(23)	6	—
Adoption of new accounting standard (Note 1)	1	—	—	—
Other comprehensive income, net of tax effects — cash flow hedges (net of tax benefit of $— in all periods)	—	—	—	1
Total other comprehensive income (loss)	(5)	(23)	6	1
Comprehensive income (loss)	(61)	(277)	(157)	22,852
Less: Comprehensive loss attributable to noncontrolling interest	2	—	—	
Comprehensive loss attributable to Vistra Energy	$ (59)	$ (277)	$ (157)	

See Notes to the Consolidated Financial Statements.

VISTRA ENERGY CORP.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Millions of Dollars)

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Cash flows — operating activities:				
Net income (loss)	$ (56)	$ (254)	$ (163)	$ 22,851
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:				
Depreciation and amortization	1,533	835	285	532
Deferred income tax expense (benefit), net	(62)	418	(76)	(1,270)
Unrealized net (gain) loss from mark-to-market valuations of commodities	380	145	165	36
Unrealized net (gain) loss from mark-to-market valuations of interest rate swaps	5	(29)	11	—
Gain on extinguishment of liabilities subject to compromise (Note 6)	—	—	—	(24,344)
Net loss from adopting fresh start reporting (Note 5)	—	—	—	2,013
Contract claims adjustments of Predecessor (Note 5)	—	—	—	13
Impairment of long-lived assets (Note 4)	—	25	—	—
Write-off of intangible and other assets (Note 23)	—	—	—	45
Impacts of Tax Receivable Agreement (Note 10)	79	(213)	22	—
Change in asset retirement obligation liability	(27)	112	—	—
Asset retirement obligation accretion expense	50	60	6	—
Stock-based compensation	73	—	—	—
Other, net	92	69	1	63
Changes in operating assets and liabilities:				
Affiliate accounts receivable/payable — net	—	—	—	31
Accounts receivable — trade	(207)	7	135	(216)
Inventories	61	22	3	71
Accounts payable — trade	90	(30)	(79)	26
Commodity and other derivative contractual assets and liabilities	(80)	(1)	(48)	29
Margin deposits, net	(221)	146	(193)	(124)
Accrued interest	(105)	(10)	32	(10)
Accrued taxes	(64)	33	12	(13)
Accrued employee incentive	40	(24)	24	(30)
Alcoa contract settlement (Note 4)	—	238	—	—
Tax Receivable Agreement payment (Note 10)	(16)	(26)	—	—
Major plant outage deferral	(22)	(66)	—	—
Other — net assets	73	4	(2)	(3)
Other — net liabilities	(145)	(75)	(54)	62
Cash provided by (used in) operating activities	1,471	1,386	81	(238)
Cash flows — financing activities:				
Issuances of long-term debt (Note 14)	1,000	—	—	—
Repayments/repurchases of debt (Note 14)	(3,075)	(191)	—	(2,655)
Net borrowings under accounts receivable securitization program (Note 13)	339	—	—	—
Debt tender offer and other debt financing fee	(236)	(8)	—	—
Stock repurchase (Note 16)	(763)	—	—	—

VISTRA ENERGY CORP.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Millions of Dollars)

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Incremental Term Loan B Facility (Note 14)	—	—	1,000	—
Special Dividend (Note 16)	—	—	(992)	—
Net proceeds from issuance of preferred stock (Note 5)	—	—	—	69
Payments to extinguish claims of TCEH first lien creditors (Note 5)	—	—	—	(486)
Payment to extinguish claims of TCEH unsecured creditors (Note 5)	—	—	—	(429)
Borrowings under TCEH DIP Roll Facilities and DIP Facility (Note 14)	—	—	—	4,680
TCEH DIP Roll Facilities and DIP Facility financing fees	—	—	—	(112)
Other, net	12	(2)	(2)	(8)
Cash provided by (used in) financing activities	(2,723)	(201)	6	1,059
Cash flows — investing activities:				
Capital expenditures, including LTSA prepayments	(378)	(114)	(48)	(230)
Nuclear fuel purchases	(118)	(62)	(41)	(33)
Development and growth expenditures (Note 3)	(34)	(190)	—	—
Cash acquired in the Merger	445	—	—	—
Odessa acquisition (Note 3)	—	(355)	—	—
Lamar and Forney acquisition — net of cash acquired (Note 3)	—	—	—	(1,343)
Changes in restricted cash (Predecessor)	—	—	—	233
Proceeds from sales of nuclear decommissioning trust fund securities (Note 23)	252	252	25	201
Investments in nuclear decommissioning trust fund securities (Note 23)	(274)	(272)	(30)	(215)
Notes/advances due from affiliates	—	—	—	(41)
Other, net	6	14	1	8
Cash used in investing activities	(101)	(727)	(93)	(1,420)
Net change in cash, cash equivalents and restricted cash (Successor); Net change in cash and cash equivalents (Predecessor)	(1,353)	458	(6)	(599)
Cash, cash equivalents and restricted cash — beginning balance (Successor); Cash and cash equivalents — beginning balance (Predecessor)	2,046	1,588	1,594	1,400
Cash, cash equivalents and restricted cash — ending balance (Successor); Cash and cash equivalents — ending balance (Predecessor)	$ 693	$ 2,046	$ 1,588	$ 801

See Notes to the Consolidated Financial Statements.

VISTRA ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	Year Ended December 31,	
	2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 636	$ 1,487
Restricted cash (Note 23)	57	59
Trade accounts receivable — net (Note 23)	1,087	582
Inventories (Note 23)	412	253
Commodity and other derivative contractual assets (Note 18)	730	190
Margin deposits related to commodity contracts	361	30
Prepaid expense and other current assets	152	72
Total current assets	3,435	2,673
Restricted cash (Note 23)	—	500
Investments (Note 23)	1,250	1,240
Investment in unconsolidated subsidiary (Note 23)	131	—
Property, plant and equipment — net (Note 23)	14,612	4,820
Goodwill (Note 8)	2,068	1,907
Identifiable intangible assets — net (Note 8)	2,493	2,530
Commodity and other derivative contractual assets (Note 18)	109	58
Accumulated deferred income taxes (Note 9)	1,336	710
Other noncurrent assets	590	162
Total assets	$ 26,024	$ 14,600
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts receivable securitization program (Note 13)	$ 339	$ —
Long-term debt due currently (Note 14)	191	44
Trade accounts payable	945	473
Commodity and other derivative contractual liabilities (Note 18)	1,376	224
Margin deposits related to commodity contracts	4	4
Accrued taxes	10	58
Accrued taxes other than income	182	136
Accrued interest	77	16
Asset retirement obligations (Note 23)	156	99
Other current liabilities	345	297
Total current liabilities	3,625	1,351
Long-term debt, less amounts due currently (Note 14)	10,874	4,379
Commodity and other derivative contractual liabilities (Note 18)	270	102
Accumulated deferred income taxes (Note 9)	10	—
Tax Receivable Agreement obligation (Note 10)	420	333
Asset retirement obligations (Note 23)	2,217	1,837
Identifiable intangible liabilities — net (Note 8)	401	36
Other noncurrent liabilities and deferred credits (Note 23)	340	220
Total liabilities	18,157	8,258

VISTRA ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	Year Ended December 31,	
Commitments and Contingencies (Note 15)		
Total equity (Note 16):		
Common stock (par value — \$0.01; number of shares authorized — 1,800,000,000) (shares outstanding: December 31, 2018 — 493,215,309; December 31, 2017 — 428,398,802)	5	4
Additional paid-in-capital	9,329	7,765
Retained deficit	(1,449)	(1,410)
Accumulated other comprehensive income (loss)	(22)	(17)
Stockholders' equity	7,863	6,342
Noncontrolling interest in subsidiary	4	—
Total equity	7,867	6,342
Total liabilities and equity	\$ 26,024	\$ 14,600

See Notes to the Consolidated Financial Statements.

VISTRA ENERGY CORP.
STATEMENTS OF CONSOLIDATED EQUITY
(Millions of Dollars)

	Common Stock (Successor) / Capital Account (Predecessor)	Additional Paid-In Capital (Successor)	Retained Deficit (Successor)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests (Successor)	Total Equity
Equity in Successor:							
Balances at October 3, 2016	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Shares issued upon Emergence	4	7,737	—	—	7,741	—	7,741
Effects of stock-based compensation	—	4	—	—	4	—	4
Other issuances of common stock	—	1	—	—	1	—	1
Net loss	—	—	(163)	—	(163)	—	(163)
Dividends declared on common stock	—	—	(992)	—	(992)	—	(992)
Pension and OPEB liability — change in funded status	—	—	—	6	6	—	6
Balances at December 31, 2016	$ 4	$ 7,742	$ (1,155)	$ 6	$ 6,597	$ —	$ 6,597
Effects of stock-based compensation	—	23	—	—	23	—	23
Net loss	—	—	(254)	—	(254)	—	(254)
Pension and OPEB liability — change in funded status	—	—	—	(23)	(23)	—	(23)
Other	—	—	(1)	—	(1)	—	(1)
Balances at December 31, 2017	$ 4	$ 7,765	$ (1,410)	$ (17)	$ 6,342	$ —	$ 6,342
Stock and stock compensation awards issued in connection with the Merger	1	1,901	—	—	1,902	—	1,902
Treasury stock	—	(778)	—	—	(778)	—	(778)
Effects of stock-based compensation	—	72	—	—	72	—	72
Tangible equity units acquired	—	369	—	—	369	—	369
Warrants acquired	—	2	—	—	2	—	2
Net loss	—	—	(54)	—	(54)	(2)	(56)
Adoption of new accounting standards (Note 1)	—	—	16	1	17	—	17
Pension and OPEB liability — change in funded status	—	—	—	(6)	(6)	—	(6)
Investment by noncontrolling interest	—	—	—	—	—	6	6
Other	—	(2)	(1)	—	(3)	—	(3)
Balances at December 31, 2018	$ 5	$ 9,329	$ (1,449)	$ (22)	$ 7,863	$ 4	$ 7,867
Membership interests in Predecessor:							
Balances at December 31, 2015	$ (22,851)	$ —	$ —	$ (33)	$ (22,884)		
Net income	22,851	—	—	—	22,851		
Cash flow hedges — change during period	—	—	—	33	33		
Balances at October 2, 2016	$ —	$ —	$ —	$ —	$ —		

See Notes to the Consolidated Financial Statements.

1. BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Description of Business

References in this report to "we," "our," "us" and "the Company" are to Vistra Energy and/or its subsidiaries in the Successor period, and to TCEH and/or its subsidiaries in the Predecessor periods, as apparent in the context. See *Glossary* for defined terms.

Vistra Energy is a holding company operating an integrated retail and generation business in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive electricity market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity to end users.

Vistra Energy has six reportable segments: (i) Retail, (ii) ERCOT, (iii) PJM, (iv) NY/NE (comprising NYISO and ISO-NE), (v) MISO and (vi) Asset Closure. The PJM, NY/NE and MISO segments were established on the Merger Date to reflect markets served by businesses acquired in the Merger. See Note 22 for further information concerning reportable business segments.

On the Petition Date, EFH Corp. and the substantial majority of its direct and indirect subsidiaries, including the Debtors, filed voluntary petitions for relief under the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware.

On the Effective Date, subsidiaries of TCEH that were Debtors in the Chapter 11 Cases (the TCEH Debtors) and certain EFH Corp. subsidiaries (the Contributed EFH Debtors) completed their reorganization under the Bankruptcy Code and emerged from the Chapter 11 Cases as subsidiaries of a newly formed company, Vistra Energy (our Successor). On the Effective Date, Vistra Energy was spun-off from EFH Corp. in a tax-free transaction to the former first lien creditors of TCEH (Spin-Off). As a result, as of the Effective Date, Vistra Energy is a holding company for subsidiaries principally engaged in competitive electricity market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity to end users. TCEH is the Predecessor to Vistra Energy. See Note 5 for further discussion regarding the Chapter 11 Cases.

Merger Transaction

On the Merger Date, Vistra Energy and Dynegy completed the transactions contemplated by the Merger Agreement. Pursuant to the Merger Agreement, Dynegy merged with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. Because the Merger closed on April 9, 2018, Vistra Energy's consolidated financial statements and the notes related thereto do not include the financial condition or the operating results of Dynegy prior to April 9, 2018. See Note 2 for a summary of the Merger transaction and business combination accounting.

Basis of Presentation

As of the Effective Date, Vistra Energy applied fresh start reporting under the applicable provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852, *Reorganizations* (ASC 852). Fresh start reporting included (1) distinguishing the consolidated financial statements of the entity that was previously in restructuring (TCEH, or the Predecessor) from the financial statements of the entity that emerges from restructuring (Vistra Energy, or the Successor), (2) accounting for the effects of the Plan of Reorganization, (3) assigning the reorganization value of the Successor entity by measuring all assets and liabilities of the Successor entity at fair value, and (4) selecting accounting policies for the Successor entity. The financial statements of Vistra Energy for periods subsequent to the Effective Date are not comparable to the financial statements of TCEH for periods prior to the Effective Date, as those previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities that resulted from the Plan of Reorganization and the related application of fresh start reporting. The reorganization value of Vistra Energy was assigned to its assets and liabilities in conformity with the procedures specified by FASB ASC 805, *Business Combinations*, and the portion of the reorganization value that was not attributable to identifiable tangible or intangible assets was recognized as goodwill. See Note 6 for further discussion of fresh start reporting.

The consolidated financial statements of the Predecessor reflect the application of ASC 852 as it applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. As a result, the consolidated financial statements of the Predecessor have been prepared as if TCEH was a going concern and contemplated the realization of assets and liabilities in the normal course of business. During the Chapter 11 Cases, the Debtors operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities. Prior to the Effective Date, the Predecessor recorded the effects of the Plan of Reorganization in accordance with ASC 852. See *Predecessor Reorganization Items* in Note 5 for further discussion of these accounting and reporting changes.

The consolidated financial statements have been prepared in accordance with U.S. GAAP and on the same basis as the audited financial statements included in our annual report on Form 10-K for the year ended December 31, 2017, with the exception of the changes in reportable segments as detailed above. Adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the results of operations and financial position have been included therein. All intercompany items and transactions have been eliminated in consolidation. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated.

Use of Estimates

Preparation of financial statements requires estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and the reported amounts of revenue and expense, including fair value measurements, estimates of expected obligations, judgment related to the potential timing of events and other estimates. In the event estimates and/or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of electricity, natural gas, coal, uranium and other commodities utilizing instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. If the instrument meets the definition of a derivative under accounting standards related to derivative instruments and hedging activities, changes in the fair value of the derivative are recognized in net income as unrealized gains and losses. This recognition is referred to as mark-to-market accounting. The fair values of our unsettled derivative instruments under mark-to-market accounting are reported in the consolidated balance sheets as commodity and other derivative contractual assets or liabilities. We report derivative assets and liabilities in the consolidated balance sheets without taking into consideration netting arrangements we have with counterparties. Margin deposits that contractually offset these assets and liabilities are reported separately in the consolidated balance sheets, except for certain margin amounts related to changes in fair value on CME transactions that, beginning in January 2017, are legally characterized as settlement of derivative contracts rather than collateral. When derivative instruments are settled and realized gains and losses are recorded, the previously recorded unrealized gains and losses and derivative assets and liabilities are reversed. See Notes 17 and 18 for additional information regarding fair value measurement and commodity and other derivative contractual assets and liabilities. A commodity-related derivative contract may be designated as a normal purchase or sale if the commodity is to be physically received or delivered for use or sale in the normal course of business. If designated as normal, the derivative contract is accounted for under the accrual method of accounting (not marked-to-market) with no balance sheet or income statement recognition of the contract until settlement.

Because derivative instruments are frequently used as economic hedges, accounting standards related to derivative instruments and hedging activities allow for hedge accounting, which provides for the designation of such instruments as cash flow or fair value hedges if certain conditions are met. At December 31, 2018 and 2017, there were no derivative positions accounted for as cash flow or fair value hedges.

For the Successor period, we report commodity hedging and trading results as revenue, fuel expense or purchased power in the statements of consolidated income (loss) depending on the type of activity. Electricity hedges, financial natural gas hedges and trading activities are primarily reported as revenue. Physical or financial hedges for coal, diesel or uranium, along with physical natural gas trades, are primarily reported as fuel expense. For the Predecessor periods, all activity was reported as a net gain (loss) from commodity hedging and trading activities. Realized and unrealized gains and losses associated with interest rate swap transactions are reported in the statements of consolidated income (loss) in interest expense for both the Predecessor and Successor.

Revenue Recognition

Revenue is recognized when electricity is delivered to our customers in an amount that we expect to invoice for volumes delivered or services provided. Sales tax is excluded from revenue. Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Estimated amounts are adjusted when actual usage is known and billed. See Note 7 for detailed descriptions of revenue from contracts with customers.

We record wholesale generation revenue when volumes are delivered or services are performed for transactions that are not accounted for on a mark-to-market basis. These revenues primarily consist of physical electricity sales to the ISO or RTO, ancillary service revenue for reliability services, capacity revenue for making installed generation and demand response available for system reliability requirements, and certain other electricity sales contracts. See Note 7 for detailed descriptions of revenue from contracts with customers. See *Derivative Instruments and Mark-to-Market Accounting* for revenue recognition related to derivative contracts.

Advertising Expense

We expense advertising costs as incurred and include them within selling, general and administrative expenses. Advertising expenses totaled $46 million, $44 million, $9 million and $35 million for the Successor period for the year ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively.

Impairment of Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever indications of impairment exist. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable.

Finite-lived intangibles identified as a result of fresh start reporting or purchase accounting are amortized over their estimated useful lives based on the expected realization of economic effects. See Note 8 for details of intangible assets with indefinite lives, including discussion of fair value determinations.

Goodwill and Intangible Assets with Indefinite Lives

As part of fresh start reporting and purchase accounting, reorganization value or the purchase consideration is generally allocated, first, to identifiable tangible assets, identifiable intangible assets and liabilities, then any remaining excess reorganization value is allocated to goodwill (see Note 6). We evaluate goodwill and intangible assets with indefinite lives for impairment at least annually, or when indications of impairment exist. We have established October 1 as the date we evaluate goodwill and intangible assets with indefinite lives for impairment. The Predecessor's annual evaluation date was December 1. See Note 8 for details of goodwill, including discussion of fair value determinations.

Nuclear Fuel

Nuclear fuel is capitalized and reported as a component of our property, plant and equipment in our consolidated balance sheets. Amortization of nuclear fuel is calculated on the units-of-production method and is reported as a component of fuel, purchased power costs and delivery fees in our statements of consolidated income (loss).

Major Maintenance Costs

Major maintenance costs incurred by the Successor during generation plant outages are deferred and amortized into operating costs over the period between the major maintenance outages for the respective asset. Other routine costs of maintenance activities are charged to expense as incurred and reported as operating costs in our statements of consolidated income (loss). The Predecessor charged all maintenance activities to expense as incurred.

Defined Benefit Pension Plans and OPEB Plans

On the Merger Date, Vistra Energy assumed the pension and OPEB plans that Dynegy had provided to certain of its eligible employees and retirees. The excess of the benefit obligations over the fair value of plan assets was recognized as a liability. See Note 2 for additional information regarding the Merger.

On the Effective Date, EFH Corp. transferred sponsorship of certain employee benefit plans (including related assets), programs and policies to a subsidiary of Vistra Energy. Certain health care and life insurance benefits are offered to eligible employees and their dependents upon the retirement of such employee from the company. Pension benefits are offered to eligible employees under collective bargaining agreements based on either a traditional defined benefit formula or a cash balance formula. Effective January 1, 2017, the OPEB plan was amended to discontinue the life insurance benefits for active employees. Costs of pension and OPEB plans are dependent upon numerous factors, assumptions and estimates.

Prior to the Effective Date, our Predecessor bore a portion of the costs of the EFH Corp. sponsored pension and OPEB plans and accounted for the arrangement under multiple employer plan accounting.

See Note 19 for additional information regarding pension and OPEB plans.

Stock-Based Compensation

Stock-based compensation is accounted for in accordance with ASC 718, *Compensation - Stock Compensation.* The fair value of our non-qualified stock options is estimated on the date of grant using the Black-Scholes option-pricing model. Forfeitures are recognized as they occur. We recognize compensation expense for graded vesting awards on a straight-line basis over the requisite service period for the entire award. See Note 20 for additional information regarding stock-based compensation.

Sales and Excise Taxes

Sales and excise taxes are accounted for as "pass through" items on the consolidated balance sheets with no effect on the statements of consolidated income (loss) (*i.e.*, the tax is billed to customers and recorded as trade accounts receivable with an offsetting amount recorded as a liability to the taxing jurisdiction).

Franchise and Revenue-Based Taxes

Unlike sales and excise taxes, franchise and gross receipt taxes are not a "pass through" item. These taxes are imposed on us by state and local taxing authorities, based on revenues or kWh delivered, as a cost of doing business and are recorded as an expense. Rates we charge to customers are intended to recover our costs, including the franchise and gross receipt taxes, but we are not acting as an agent to collect the taxes from customers. We report franchise and revenue-based taxes in SG&A expense in our statements of consolidated income (loss).

Income Taxes

On the Merger Date, Vistra Energy and Dynegy effected a merger transaction that for tax purposes was treated as a tax-free reorganization in which Vistra Energy survived as the parent entity. In general, all of Dynegy's tax basis and attributes were transferred to Vistra Energy, including approximately $4.2 billion of utilizable NOLs and refundable AMT tax credits.

Prior to the Effective Date, EFH Corp. filed a consolidated U.S. federal income tax return that included the results of our Predecessor; however, our Predecessor's income tax expense and related balance sheet amounts were recorded as if it filed separate corporate income tax returns.

Investment tax credits are accounted for under the deferral method, which resulted in a reduction to the basis of the Upton 2 solar facility of $78 million and a corresponding increase in the deferred tax assets in 2018.

Deferred income taxes are provided for temporary differences between the book and tax basis of assets and liabilities as required under accounting rules. See Note 9.

We report interest and penalties related to uncertain tax positions as current income tax expense. See Note 9.

Tax Receivable Agreement

The Company accounts for its obligations under the Tax Receivable Agreement (TRA) as a liability in our consolidated balance sheets (see Note 10). The carrying value of the TRA obligation represents the discounted amount of projected payments under the TRA. The projected payments are based on certain assumptions, including but not limited to (a) the federal corporate income tax rate and (b) estimates of our taxable income in the current and future years. Our taxable income takes into consideration the current federal tax code and reflects our current estimates of future results of the business.

The carrying value of the obligation is being accreted to the amount of the gross expected obligation using the effective interest method and the interest rate estimated at the Emergence Date. Changes in the estimated amount of this obligation resulting from changes to either the timing or amount of TRA payments are recognized in the period of change and are included on our statement of consolidated income (loss) under the heading of Impacts of Tax Receivable Agreement.

Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. Accruals for loss contingencies are recorded when management determines that it is probable that a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events. See Note 15 for a discussion of contingencies.

Cash and Cash Equivalents

For purposes of reporting cash and cash equivalents, temporary cash investments purchased with a remaining maturity of three months or less are considered cash equivalents.

Restricted Cash

The terms of certain agreements require the restriction of cash for specific purposes. See Notes 14 and 23 for more details regarding restricted cash.

Property, Plant and Equipment

In connection with fresh start reporting, carrying amounts of property, plant and equipment were adjusted to estimated fair values as of the Effective Date (see Note 6). Property, plant and equipment added subsequent to the Effective Date has been recorded at estimated fair values at the time of acquisition for assets acquired or at cost for capital improvements and individual facilities developed (see Notes 2 and 3). Significant improvements or additions to our property, plant and equipment that extend the life of the respective asset are capitalized at cost, while other costs are expensed when incurred. The cost of self-constructed property additions includes materials and both direct and indirect labor, including payroll-related costs. Interest related to qualifying construction projects and qualifying software projects is capitalized in accordance with accounting guidance related to capitalization of interest cost. See Note 11.

Depreciation of our property, plant and equipment (except for nuclear fuel) is calculated on a straight-line basis over the estimated service lives of the properties. Depreciation expense is calculated on an asset-by-asset basis. Estimated depreciable lives are based on management's estimates of the assets' economic useful lives. See Note 23.

Asset Retirement Obligations (ARO)

A liability is initially recorded at fair value for an asset retirement obligation associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets in the period in which it is incurred if a fair value is reasonably estimable. At initial recognition of an ARO obligation, an offsetting asset is also recorded for the long-lived asset that the liability corresponds with, which is subsequently depreciated over the estimated useful life of the asset. These liabilities primarily relate to our nuclear generation plant decommissioning, land reclamation related to lignite mining and removal of lignite/coal-fueled plant ash treatment facilities. Over time, the liability is accreted for the change in present value and the initial capitalized costs are depreciated over the remaining useful lives of the assets. Generally, changes in estimates related to ARO obligations are recorded as increases or decreases to the liability and related asset as information becomes available. Changes in estimates related to assets that have been retired or for which capitalized costs are not recoverable are reflected in the statements of consolidated income (loss). See Note 23.

Inventories

Inventories consist of materials and supplies, fuel stock and natural gas in storage. Materials and supplies inventory is valued at weighted average cost and is expensed or capitalized when used for repairs/maintenance or capital projects, respectively. Fuel stock and natural gas in storage are reported at the lower of cost (on a weighted average basis) or market. We expect to recover the value of inventory costs in the normal course of business. See Note 23.

Investments

Investments in a nuclear decommissioning trust fund are carried at current market value in the consolidated balance sheets. Assets related to employee benefit plans represent investments held to satisfy deferred compensation liabilities and are recorded at current market value. See Note 23 for discussion of these and other investments.

Unconsolidated Investments

We use the equity method of accounting for investments in affiliates over which we exercise significant influence. Our share of net income (loss) from these affiliates is recorded to equity in earnings (loss) of unconsolidated investment in the statements of consolidated net income (loss). See Note 23.

Noncontrolling Interest

Noncontrolling interest is comprised of the 20% of Electric Energy, Inc. (EEI) that we do not own. EEI is our consolidated subsidiary that owns a coal facility in Joppa, Illinois. This noncontrolling interest is classified as a component of equity separate from stockholders' equity in the consolidated balance sheets.

Treasury Stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock, which is presented in our consolidated balance sheets as a reduction to additional paid-in capital. See Note 16.

Adoption of New Accounting Standards

Revenue from Contracts with Customers — On January 1, 2018, we adopted Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)* and all related amendments (new revenue standard) using the modified retrospective method for all contracts outstanding at the time of adoption. We recognized the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The impact of the adoption of the new revenue standard was immaterial and we expect the adoption to continue to be immaterial to our net income on an ongoing basis. Our retail energy charges and wholesale generation, capacity and contract revenues will continue to be recognized when electricity and other services are delivered to our customers. The impact of adopting the new revenue standard primarily relates to the deferral of acquisition costs associated with retail contracts with customers that were previously expensed as incurred. Under the new revenue standard, these amounts are capitalized and amortized over the expected life of the customer.

As of January 1, 2018, the cumulative effect of the changes made to our consolidated balance sheet for the adoption of the new revenue standard was as follows:

	December 31, 2017	Adoption of New Revenue Standard	January 1, 2018
Impact on consolidated balance sheet:			
Assets			
Prepaid expense and other current assets	$ 72	$ 5	$ 77
Accumulated deferred income taxes	$ 710	$ (4)	$ 706
Other noncurrent assets	$ 162	$ 16	$ 178
Equity			
Retained deficit	$ (1,410)	$ 17	$ (1,393)

The disclosure of the impact of adoption on our statement of consolidated income (loss) and consolidated balance sheet was as follows:

	Year Ended December 31, 2018		
	As Reported	Amount Without Adoption of New Revenue Standard	Effect of Change Higher (Lower)
Impact on statement of consolidated income (loss):			
Operating revenues	$ 9,144	$ 9,141	$ 3
Selling, general and administrative expenses	(926)	(939)	13
Net income (loss)	(56)	(68)	12

	December 31, 2018		
	As Reported	Balances Without Adoption of New Revenue Standard	Effect of Change Higher (Lower)
Impact on consolidated balance sheet:			
Assets			
Prepaid expense and other current assets	$ 152	$ 145	$ 7
Accumulated deferred income taxes	1,336	1,349	(13)
Other noncurrent assets	590	559	31
Equity			
Retained deficit	$ (1,449)	$ (1,478)	$ 29

See Note 7 for the disclosures required by the new revenue standard.

Statement of Cash Flows — In November 2016, the FASB issued ASU 2016-18 *Statement of Cash Flows (Topic 230): Restricted Cash*. The ASU requires restricted cash to be included in the cash and cash equivalents and a reconciliation between the change in cash and cash equivalents and the amounts presented on the balance sheet. We adopted the standard on January 1, 2018. The ASU modified our presentation of our statements of consolidated cash flows, and retrospective application to comparative periods presented was required. For the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, our statements of consolidated cash flows previously reflected a source of cash of $186 million and $48 million, respectively, reported as changes in restricted cash that is now reported in net change in cash, cash equivalents and restricted cash. See the statements of consolidated cash flows and Note 23 for disclosures related to the adoption of this accounting standard.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income — In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The ASU permits the reclassification of income tax effects of the Tax Cuts and Jobs Act on items within accumulated other comprehensive income (AOCI) to retained earnings. We adopted this ASU in the fourth quarter of 2018, and the impact was additional tax expense to AOCI of $1 million with the offset to retained earnings.

Changes to the Disclosure Requirements for Defined Benefit Plans — In August 2018, the FASB issued ASU 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*. The ASU removes disclosure requirements for (a) the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost over the next fiscal year, (b) related party disclosures about the amount of future annual benefits covered by insurance and annuity contracts and significant transactions between the employer or related parties and the plan and (c) the effects of a one-percentage-point change in assumed health care cost trend rates on the aggregate of the service and interest cost components of net periodic benefit costs and benefit obligation for postretirement health care benefits. The ASU requires new disclosures for (a) the weighted-average interest crediting rates for cash balance plans and other plans with promised interest crediting rates and (b) an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period. We adopted this ASU in the fourth quarter of 2018, and the updated disclosures are included in Note 19.

Leases — In February 2016, the Financial Accounting Standards Board (FASB) issued ASU 2016-02, *Leases* (ASU 2016-02), which was further amended through several updates issued by the FASB in 2018. The ASU amends previous GAAP to require lessees to recognize leases on-balance sheet and disclose key information about leasing arrangements. The ASU requires the lessee to recognize a right-of-use asset and lease liability on the balance sheet for all leases. Leases will be classified as finance and operating with classifications affecting the pattern and expense recognition in the income statement.

We adopted the new standard on January 1, 2019 using the modified retrospective approach. The new standard provides a number of optional practical expedients in transition. We have elected the practical expedient which permits us to not reassess our prior conclusion about lease classification and initial direct costs under the new standard. We have also elected the practical expedient to not separate lease and non-lease components for all applicable asset classes. We have also elected the short-term lease recognition exemption for all leases that qualify. On adoption, we currently expect to recognize additional liabilities within the range of approximately $230 million to $280 million, with corresponding right-of-use assets of the same amount based on the present value of the remaining rental payments for existing leases. The adoption of this standard will have an immaterial impact to beginning retained earnings and the statements of consolidated income (loss).

Changes in Accounting Standards

In August 2018, the FASB issued ASU 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement.* The ASU will be effective for fiscal years beginning after December 15, 2019 and early adoption is permitted. The ASU removes disclosure requirements for (a) the reasons for transfers between Level 1 and Level 2, (b) the policy for timing of transfers between levels and (c) the valuation processes for Level 3. The ASU will require new disclosures around (a) the changes in unrealized gains and losses for the period included in other comprehensive income for recurring Level 3 fair value measurements held at the end of the reporting period and (b) the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. We are currently evaluating the impact of this ASU on our disclosures.

In August 2018, the FASB issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract.* The ASU will be effective for fiscal years beginning after December 15, 2019 and early adoption is permitted. The ASU requires a customer in a cloud hosting arrangement that is a service contract to determine which implementation costs to capitalize and which costs to expense based on the project stage of the implementation. The ASU also requires the customer to expense the capitalized implementation costs over the term of the hosting arrangement. The customer is required to apply the existing impairment and abandonment guidance on the capitalized implementation costs. We are currently evaluating the impact of this ASU on our financial statements.

2. MERGER TRANSACTION AND BUSINESS COMBINATION ACCOUNTING

On the Merger Date, Vistra Energy and Dynegy, completed the transactions contemplated by the Merger Agreement. Pursuant to the Merger Agreement, Dynegy merged with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. The Merger is intended to qualify as a tax-free reorganization under the Internal Revenue Code, as amended, so that none of Vistra Energy, Dynegy or any of the Dynegy stockholders will recognize any gain or loss in the transaction, except that Dynegy stockholders could recognize a gain or loss with respect to cash received in lieu of fractional shares of Vistra Energy's common stock. Vistra Energy is the acquirer for both federal tax and accounting purposes.

At the closing of the Merger, each issued and outstanding share of Dynegy common stock, par value $0.01 per share, other than shares owned by Vistra Energy or its subsidiaries, held in treasury by Dynegy or held by a subsidiary of Dynegy, was automatically converted into 0.652 shares of common stock, par value $0.01 per share, of Vistra Energy (the Exchange Ratio), except that cash was paid in lieu of fractional shares, which resulted in Vistra Energy issuing 94,409,573 shares of Vistra Energy common stock to the former Dynegy stockholders, as well as converting stock options, equity-based awards, tangible equity units and warrants. The total number of Vistra Energy shares outstanding at the close of the Merger was 522,932,453 shares. Dynegy stock options and equity-based awards outstanding immediately prior to the Merger Date were generally automatically converted upon completion of the Merger into stock options and equity-based awards, respectively, with respect to Vistra Energy's common stock, after giving effect to the Exchange Ratio.

Business Combination Accounting

We believe the Merger provides significant potential strategic benefits and opportunities to Vistra Energy, including increased scale and market diversification, rebalanced asset portfolio and improved earnings and cash flow. The Merger is being accounted for in accordance with ASC 805, *Business Combinations* (ASC 805), with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the Merger Date. The combined results of operations are reported in our consolidated financial statements beginning as of the Merger Date. A summary of the techniques used to estimate the preliminary fair value of the identifiable assets and liabilities, as well as their classification within the fair value hierarchy (see Note 17), is listed below:

- Working capital was valued using available market information (Level 2).
- Acquired property, plant and equipment was valued using a combination of an income approach and a market approach. The income approach utilized a discounted cash flow analysis based upon a debt-free, free cash flow model (Level 3).
- Acquired derivatives were valued using the methods described in Note 17 (Level 1, Level 2 or Level 3).
- Contracts with terms that were not at current market prices were also valued using a discounted cash flow analysis (Level 3). The cash flows generated by the contracts were compared with their cash flows based on current market prices with the resulting difference discounted to present value and recorded as either an intangible asset or liability.
- Long-term debt was valued using a market approach (Level 2).
- AROs were recorded in accordance with ASC 410, *Asset Retirement and Environmental Obligations* (Level 3).

The following table summarizes the consideration paid and the preliminary allocation of the purchase price to the fair value amounts recognized for the assets acquired and liabilities assumed related to the Merger as of the Merger Date. Based on the opening price of Vistra Energy common stock on the Merger Date, the purchase price was approximately $2.3 billion. The preliminary values included below represent our current best estimates for property plant and equipment, identifiable intangible assets and liabilities, goodwill, inventories, asset retirement obligations, contingent liabilities and deferred taxes. During the year ended December 31, 2018, we updated the initial purchase price allocation reported as of June 30, 2018 with revised valuation estimates by increasing property, plant and equipment by $158 million, decreasing intangible assets by $36 million, increasing goodwill by $161 million, decreasing accounts receivable, inventory, prepaid expenses and other current assets by $7 million, increasing accumulated deferred tax asset by $101 million, decreasing other noncurrent assets by $109 million, increasing trade accounts payable and other current liabilities by $43 million, increasing other noncurrent liabilities by $172 million, increasing asset retirement obligations, including amounts due currently by $58 million as well as other minor adjustments. The valuation revisions were a result of updated inputs used in determining the fair value of the acquired assets and liabilities. The purchase price allocation is substantially complete, but is dependent upon final valuation determinations, which may materially change from our current estimates. Goodwill is currently recorded at the corporate and other non-segment operations pending the final valuation determinations. We currently expect the final purchase price allocation will be completed no later than the first quarter of 2019 and goodwill will be allocated to the related reporting units at that time.

Dynegy shares outstanding as of April 9, 2018 (in millions)		144.8
Exchange Ratio		0.652
Vistra Energy shares issued for Dynegy shares outstanding (in millions)		94.4
Opening price of Vistra Energy common stock on April 9, 2018	$	19.87
Purchase price for common stock	$	1,876
Fair value of equity component of tangible equity units	$	369
Fair value of outstanding stock compensation awards attributable to pre-combination service	$	26
Fair value of outstanding warrants	$	2
Total purchase price	$	2,273

Preliminary Purchase Price Allocation

Cash and cash equivalents	$	445
Trade accounts receivables, inventories, prepaid expenses and other current assets		856
Property, plant and equipment		10,520
Accumulated deferred income taxes		492
Identifiable intangible assets		351
Goodwill		161
Other noncurrent assets		423
Total assets acquired		13,248
Trade accounts payable and other current liabilities		687
Commodity and other derivative contractual assets and liabilities, net		422
Asset retirement obligations, including amounts due currently		477
Long-term debt, including amounts due currently		8,920
Other noncurrent liabilities		464
Total liabilities assumed		10,970
Identifiable net assets acquired		2,278
Noncontrolling interest in subsidiary		5
Total purchase price	$	2,273

Acquisition costs incurred in the Merger totaled $25 million for the year ended December 31, 2018. For the period from the Merger Date through December 31, 2018, our statements of consolidated income (loss) include revenues and net income (loss) acquired in the Merger totaling $3.902 billion and $224 million respectively.

Unaudited Pro Forma Financial Information — The following unaudited pro forma financial information for the year ended December 31, 2018 and 2017 assumes that the Merger occurred on January 1, 2017. The unaudited pro forma financial information is provided for information purposes only and is not necessarily indicative of the results of operations that would have occurred had the Merger been completed on January 1, 2017, nor is the unaudited pro forma financial information indicative of future results of operations, which may differ materially from the pro forma financial information presented here.

	Year Ended December 31,			
	2018		2017	
Revenues	$	10,595	$	10,509
Net loss	$	(268)	$	(969)
Net loss attributable to Vistra Energy	$	(265)	$	(983)
Net loss attributable to Vistra Energy per weighted average share of common stock outstanding — basic	$	(0.52)	$	(1.83)
Net loss attributable to Vistra Energy per weighted average share of common stock outstanding — diluted	$	(0.52)	$	(1.83)

The unaudited pro forma financial information presented above includes adjustments for incremental depreciation and amortization as a result of the fair value determination of the net assets acquired, interest expense on debt assumed in the Merger, effects of the Merger on tax expense (benefit), changes in the expected impacts of the tax receivable agreement due to the Merger, and other related adjustments.

3. ACQUISITION AND DEVELOPMENT OF GENERATION FACILITIES

Battery Energy Storage Projects (Successor)

We have completed the construction of our first battery energy storage system. In October 2018, we were awarded a $1 million grant from the TCEQ for our battery energy storage system at Upton 2 solar facility. The grant is part of the Texas Emissions Reduction Plan. The 10 MW lithium-ion energy storage system will capture excess solar energy produced during the day and releases the energy in late afternoon and early evening, when demand is highest. The project became operational on December 31, 2018.

In June 2018, we announced that we will enter into a 20-year resource adequacy contract with Pacific Gas and Electric Company (PG&E) to develop a 300 MW battery energy storage project at our Moss Landing Power Plant site in California. PG&E filed its application with the California Public Utilities Commission (CPUC) in June 2018 and the CPUC approved the contract in November 2018. We anticipate the battery storage project will enter commercial operations by the fourth quarter of 2020.

Odessa Acquisition (Successor)

In August 2017, La Frontera Holdings, LLC (La Frontera), an indirect wholly owned subsidiary of Vistra Energy, purchased a 1,054 MW CCGT natural gas-fueled generation plant (and other related assets and liabilities) located in Odessa, Texas (Odessa Facility) from Odessa-Ector Power Partners, L.P., an indirect wholly owned subsidiary of Koch Ag & Energy Solutions, LLC (Koch) (altogether, the Odessa Acquisition). La Frontera paid an aggregate purchase price of approximately $355 million, plus a five-year earn-out provision, to acquire the Odessa Facility. The purchase price was funded by cash on hand.

The Odessa Acquisition was accounted for as an asset acquisition. Substantially all of the approximately $355 million purchase price was assigned to property, plant and equipment in our consolidated balance sheet. Additionally, the initial fair value associated with an earn-out provision of approximately $16 million was included as consideration in the overall purchase price. The earn-out provision requires cash payments to be made to Koch if spark-spreads related to the pricing point of the Odessa Facility exceed certain thresholds. Subsequent to the acquisition, the earn-out provision has been accounted for as a derivative in our consolidated financial statements. Partial buybacks of the earn-out provision were settled in February and May 2018.

Upton 2 Solar Development (Successor)

In May 2017, we acquired the rights to develop, construct and operate a utility scale solar photovoltaic power generation facility in Upton County, Texas (Upton 2). As part of this project, we entered a turnkey engineering, procurement and construction agreement to construct the approximately 180 MW facility. During 2017 and 2018, we spent approximately $231 million related to this project primarily for progress payments under the engineering, procurement and construction agreement and the acquisition of the development rights. The facility began test operations in March 2018 and commercial operations began in June 2018.

Lamar and Forney Acquisition (Predecessor)

In April 2016, Luminant purchased all of the membership interests in La Frontera, the indirect owner of two combined-cycle gas turbine (CCGT) natural gas-fueled generation facilities representing nearly 3,000 MW of capacity located in ERCOT, from a subsidiary of NextEra Energy, Inc. (the Lamar and Forney Acquisition). The aggregate purchase price was approximately $1.313 billion, which included the repayment of approximately $950 million of existing project financing indebtedness of La Frontera at closing, plus approximately $236 million for cash and net working capital. The purchase price was funded by cash-on-hand and additional borrowings under our Predecessor's DIP Facility totaling $1.1 billion. After completing the acquisition, we repaid approximately $230 million of borrowings under our Predecessor's DIP Revolving Credit Facility primarily utilizing cash acquired in the transaction. La Frontera and its subsidiaries were subsidiary guarantors under our Predecessor's DIP Roll Facilities and, on the Effective Date, became subsidiary guarantors under the Vistra Operations Credit Facilities (see Note 14).

Predecessor Purchase Accounting — The Lamar and Forney Acquisition was accounted for in accordance with ASC 805, *Business Combinations* (ASC 805), with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date.

To fair value the acquired property, plant and equipment, we used a discounted cash flow analysis, classified as Level 3 within the fair value hierarchy levels (see Note 17). This discounted cash flow model was created for each generation facility based on its remaining useful life. The discounted cash flow model included gross margin forecasts for each power generation facility determined using forward commodity market prices obtained from long-term forecasts. We also used management's forecasts of generation output, operations and maintenance expense, SG&A and capital expenditures. The resulting cash flows, estimated based upon the age of the assets, efficiency, location and useful life, were then discounted using plant specific discount rates of approximately 9%.

The following table summarizes the consideration paid and the allocation of the purchase price to the fair value amounts recognized for the assets acquired and liabilities assumed related to the Lamar and Forney Acquisition as of the acquisition date. During the three months ended September 30, 2016, the working capital adjustment included in the purchase price was finalized between the parties, and the purchase price allocation was completed.

Cash paid to seller at close	$	603
Net working capital adjustments		(4)
Consideration paid to seller		599
Cash paid to repay project financing at close		950
Total cash paid related to acquisition	$	1,549
Cash and cash equivalents	$	210
Property, plant and equipment — net		1,316
Commodity and other derivative contractual assets		47
Other assets		44
Total assets acquired		1,617
Commodity and other derivative contractual liabilities		53
Trade accounts payable and other liabilities		15
Total liabilities assumed		68
Identifiable net assets acquired	$	1,549

The Lamar and Forney Acquisition did not result in the recording of goodwill since the purchase price did not exceed the fair value of the net assets acquired.

Unaudited Pro Forma Financial Information — The following unaudited pro forma financial information for the Predecessor period from January 1, 2016 through October 2, 2016 assumes that the Lamar and Forney Acquisition occurred on January 1, 2016. The unaudited pro forma financial information is provided for information purposes only and is not necessarily indicative of the results of operations that would have occurred had the Lamar and Forney Acquisition been completed on January 1, 2016, nor is the unaudited pro forma financial information indicative of future results of operations.

	Predecessor	
	Period from January 1, 2016 through October 2, 2016	
Revenues	$	4,116
Net income (loss)	$	22,835

The unaudited pro forma financial information includes adjustments for incremental depreciation as a result of the fair value determination of the net assets acquired and interest expense on borrowings under our Predecessor's DIP Roll Facilities.

4. RETIREMENT OF GENERATION FACILITIES

In August 2018, we filed a notice of suspension of operation with PJM and other mandatory regulatory notifications related to the retirement of our 51 MW Northeastern waste coal facility in McAddo, Pennsylvania. We decided to retire this facility due to its uneconomic operations and financial outlook. Following the receipt of regulatory approvals, the facility was retired in October 2018. The decision to retire this facility did not result in a material impact to the financial statements, and the operational results of this facility are included in our Asset Closure segment.

Two of our non-operated, jointly held power plants acquired in the Merger, for which our proportional generation capacity was 883 MW, were retired in May 2018. These units were retired as previously scheduled. No gain or loss was recorded in conjunction with the retirement of these units, and the operational results of these facilities are included in our Asset Closure segment. The following table details the units retired.

Name	Location	Fuel Type	Net Generation Capacity (MW)	Ownership Interest	Date Units Taken Offline
Killen	Manchester, Ohio	Coal	204	33%	May 31, 2018
Stuart	Aberdeen, Ohio	Coal	679	39%	May 24, 2018
Total			883		

In January and February 2018, we retired three power plants with a total installed nameplate generation capacity of 4,167 MW. We decided to retire these units because they were projected to be uneconomic based on then current market conditions and would have faced significant environmental costs associated with operating such units. In the case of the Sandow units, the decision also reflected the execution of a contract termination agreement pursuant to which the Company and Alcoa agreed to an early settlement of a long-standing power and mining agreement. Expected retirement expenses were accrued in the third and fourth quarter 2017 and, as a result, no retirement expenses were recorded related to these facilities in the year ended December 31, 2018. The operational results of these facilities are included in our Asset Closure segment. The following table details the units retired.

Name	Location (all in the state of Texas)	Fuel Type	Installed Nameplate Generation Capacity (MW)	Number of Units	Date Units Taken Offline
Monticello	Titus County	Lignite/Coal	1,880	3	January 4, 2018
Sandow	Milam County	Lignite	1,137	2	January 11, 2018
Big Brown	Freestone County	Lignite/Coal	1,150	2	February 12, 2018
Total			4,167	7	

In September and October 2017, we decided to retire our Monticello, Sandow and Big Brown plants and a related mine which supplies the Sandow plants. Management had previously announced its decisions to retire mines which supply the Monticello and Big Brown plants. The Monticello and Sandow plants were retired in January and the Big Brown plant in February 2018. We recorded a charge of approximately $206 million in 2017 related to the retirements, including employee-related severance costs, non-cash charges for writing off materials inventory and capitalized improvements and changes to the timing and amounts of asset retirement obligations for mining and plant-related reclamation at these facilities. The charge, all of which related to our Asset Closure segment, was recorded to operating costs and impairment of long-lived assets in our statements of consolidated income (loss). In addition, we will continue the ongoing reclamation work at the plants' mines.

In October 2017, the Company and Alcoa entered into a contract termination agreement pursuant to which the parties agreed to an early settlement of a long-standing power and mining agreement. In consideration for the early termination, Alcoa made a payment to Luminant of approximately $238 million in October 2017. The contract termination and related payment did not result in a material gain or loss. The contract had been important to the overall economic viability of the Sandow plant.

Regulatory Review — As part of the retirement process, Luminant filed notices with ERCOT, which triggered a reliability review regarding such proposed retirements. In October and November 2017, ERCOT determined the units were not needed for reliability, and the units were taken offline in January and February 2018.

5. EMERGENCE FROM CHAPTER 11 CASES

On the Petition Date, EFH Corp. and the substantial majority of its direct and indirect subsidiaries, including EFIH, EFCH and TCEH, but excluding the Oncor Ring-Fenced Entities, filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. On the Effective Date, the TCEH Debtors and the Contributed EFH Debtors completed their reorganization under the Bankruptcy Code and emerged from the Chapter 11 Cases as subsidiaries of Vistra Energy.

Separation of Vistra Energy from EFH Corp. and its Subsidiaries

Upon the Effective Date, Vistra Energy separated from EFH Corp. pursuant to a tax-free spin-off transaction that was part of a series of transactions that included a taxable component. The taxable portion of the transaction generated a taxable gain that resulted in no regular tax liability due to available net operating loss carryforwards of EFH Corp. The transaction did result in an alternative minimum tax liability estimated to be approximately $14 million payable by EFH Corp. to the IRS. Pursuant to the Tax Matters Agreement, Vistra Energy had an obligation to reimburse EFH Corp. 50% of the estimated alternative minimum tax, and approximately $7 million was reimbursed during the three months ended June 30, 2017. In October 2017, the 2016 federal tax return that included the results of EFCH, EFIH, Oncor Holdings and TCEH was filed with the IRS and resulted in a $3 million payment from EFH Corp. to Vistra Energy. The spin-off transaction resulted in Vistra Energy, including the TCEH Debtors and the Contributed EFH Debtors, no longer being an affiliate of EFH Corp. and its subsidiaries.

Separation Agreement

On the Effective Date, EFH Corp., Vistra Energy and a subsidiary of Vistra Energy entered into a separation agreement that provided for, among other things, the transfer of certain assets and liabilities by EFH Corp., EFCH and TCEH to Vistra Energy. Among other things, EFH Corp., EFCH and/or TCEH, as applicable, (a) transferred the TCEH Debtors and certain contracts and assets (and related liabilities) primarily related to the business of the TCEH Debtors to Vistra Energy, (b) transferred sponsorship of certain employee benefit plans (including related assets), programs and policies to a subsidiary of Vistra Energy and (c) assigned certain employment agreements from EFH Corp. and certain of the Contributed EFH Debtors to a subsidiary of Vistra Energy.

Tax Matters Agreement

On the Effective Date, Vistra Energy and EFH Corp. entered into the Tax Matters Agreement, which provides for the allocation of certain taxes among the parties and for certain rights and obligations related to, among other things, the filing of tax returns, resolutions of tax audits and preserving the tax-free nature of the spin-off.

Settlement Agreement

The Debtors, the Sponsor Group, certain settling TCEH first lien creditors, certain settling TCEH second lien creditors, certain settling TCEH unsecured creditors and the official committee of unsecured creditors of the TCEH Debtors entered into a settlement agreement (the Settlement Agreement) in August 2015 (as amended in September 2015 and approved by the Bankruptcy Court in December 2015) to settle, among other things, (a) intercompany claims among the Debtors, (b) claims and causes of actions against holders of first lien claims against TCEH and the agents under the TCEH Senior Secured Facilities, (c) claims and causes of action against holders of interests in EFH Corp. and certain related entities and (d) claims and causes of action against each of the Debtors' current and former directors, the Sponsor Group, managers and officers and other related entities.

Tax Matters

In July 2016, EFH Corp. received a private letter ruling from the IRS in connection with our emergence from bankruptcy, which provides, among other things, for certain rulings regarding the qualification of (a) the transfer of certain assets and ordinary course operating liabilities to Vistra Energy and (b) the distribution of the equity of Vistra Energy, the cash proceeds from Vistra Energy debt, the cash proceeds from the sale of preferred stock in a newly formed subsidiary of Vistra Energy, and the right to receive payments under a tax receivables agreement, to holders of TCEH first lien claims, as a reorganization qualifying for tax-free treatment.

Pre-Petition Claims

On the Effective Date, the TCEH Debtors (together with the Contributed EFH Debtors) emerged from the Chapter 11 Cases and discharged approximately $33.8 billion in LSTC. Initial distributions related to the allowed claims asserted against the TCEH Debtors and the Contributed EFH Debtors commenced subsequent to the Effective Date. As of December 31, 2018, the TCEH Debtors have approximately $52 million in escrow to (1) distribute to holders of currently contingent and/or disputed unsecured claims that become allowed and/or (2) make further distributions to holders of previously allowed unsecured claims, if applicable. Additionally, the TCEH Debtors have approximately $5 million in escrow to pay remaining professional fees incurred in the Chapter 11 Cases. The remaining contingent and/or disputed claims against the TCEH Debtors consist primarily of unsecured legal claims, including asbestos claims. These remaining claims and the related escrow balance for the claims are recorded in Vistra Energy's consolidated balance sheet as other current liabilities and current restricted cash, respectively. A small number of other disputed, de minimis claims that are asserted as being entitled to priority and/or against the Contributed EFH Debtors, if allowed, will be paid by Vistra Energy, but all non-priority unsecured claims, including asbestos claims arising before the Petition Date, will be satisfied solely from the approximately $52 million in escrow.

Predecessor Reorganization Items

Expenses and income directly associated with the Chapter 11 Cases are reported separately in the statements of consolidated income (loss) as reorganization items as required by ASC 852, *Reorganizations*. Reorganization items also included adjustments to reflect the carrying value of LSTC at their estimated allowed claim amounts, as such adjustments were determined. The following table presents reorganization items incurred in the Predecessor period from January 1, 2016 through October 2, 2016 as reported in the statements of consolidated income (loss):

	Predecessor
	Period from January 1, 2016 through October 2, 2016
Gain on reorganization adjustments (Note 6)	$ (24,252)
Loss from the adoption of fresh start reporting	2,013
Expenses related to legal advisory and representation services	55
Expenses related to other professional consulting and advisory services	39
Contract claims adjustments	13
Other	11
Total reorganization items	$ (22,121)

6. FRESH START REPORTING

As of the Effective Date, Vistra Energy applied fresh start reporting under the applicable provisions of ASC 852. In order to apply fresh-start reporting, ASC 852 requires two criteria to be satisfied: (1) that total post-petition liabilities and allowed claims immediately before the date of confirmation of the Plan of Reorganization be in excess of reorganization value and (2) that holders of our Predecessor's voting shares immediately before confirmation of the Plan receive less than 50% of the voting shares of the emerging entity. Vistra Energy met both criteria. Under ASC 852, application of fresh start reporting is required on the date on which a plan of reorganization is confirmed by a bankruptcy court and all material conditions to the plan of reorganization are satisfied. All material conditions to the Plan of Reorganization were satisfied on the Effective Date, including the execution of the Spin-Off.

Reorganization Value

A third-party valuation specialist submitted a report to the Bankruptcy Court in July 2016 assuming an emergence from bankruptcy as of December 31, 2016. This report provided an estimated value range for the total Vistra Energy enterprise. Management selected an enterprise value within that range of $10.5 billion. The enterprise value submitted by the valuation specialist was based upon:

- historical financial information of our Predecessor for recent years and interim periods;
- certain internal financial and operating data of our Predecessor;
- certain financial, tax and operational forecasts of Vistra Energy;
- certain publicly available financial data for comparable companies to the operating business of Vistra Energy;
- the Plan of Reorganization and related documents;
- certain economic and industry information relevant to the operating business, and
- other studies, analyses and inquiries.

The valuation analysis for Vistra Energy included (i) a discounted cash flow calculation and (ii) peer group company analysis. Equal weighting was assigned to the two methodologies, before adding the value of the tax basis step-up resulting from certain transactions pursuant to the Plan of Reorganization, which was valued separately. The estimated future cash flows included annual forecasts through 2021. A terminal value was included in the discounted cash flow calculation using an exit multiple approach based on the cash flows of the final year of the forecast period.

The valuation analysis used a discount rate of approximately 7%. The determination of the discount rate takes into consideration the capital structure, credit ratings and current debt yields of comparable publicly traded companies as well as an estimate of return on equity that reflects historical market returns and current market volatility for the industry.

Although the Company believes the assumptions and estimates used by the valuation specialist to develop the enterprise value are reasonable and appropriate, different assumption and estimates could materially impact the analysis and resulting conclusions.

Under ASC 852, reorganization value is generally allocated, first, to identifiable tangible assets, identifiable intangible assets and liabilities, then any remaining excess reorganization value is allocated to goodwill. Vistra Energy estimates its reorganization value of assets at approximately $15.161 billion as of October 3, 2016, which consists of the following:

Business enterprise value	$	10,500
Cash excluded from business enterprise value		1,594
Deferred asset related to prepaid capital lease obligation		38
Current liabilities, excluding short-term portion of debt and capital leases		1,123
Noncurrent, non-interest bearing liabilities		1,906
Vistra Energy reorganization value of assets	$	15,161

Consolidated Balance Sheet

The adjustments to TCEH's October 3, 2016 consolidated balance sheet below include the impacts of the Plan of Reorganization and the adoption of fresh start reporting.

	October 3, 2016					
	TCEH (Predecessor) (1)	Reorganization Adjustments (2)		Fresh Start Adjustments		Vistra Energy (Successor)
ASSETS						
Current assets:						
Cash and cash equivalents	$ 1,829	$ (1,028)	(3)	$ —		$ 801
Restricted cash	12	131	(4)	—		143
Trade accounts receivable — net	750	4		—		754
Advances to parents and affiliates of Predecessor	78	(78)		—		—
Inventories	374	—		(86)	(17)	288
Commodity and other derivative contractual assets	255	—		—		255
Margin deposits related to commodity contracts	42	—		—		42
Other current assets	47	17		3		67
Total current assets	3,387	(954)		(83)		2,350
Restricted cash	650	—		—		650
Advance to parent and affiliates of Predecessor	17	(21)		4		—
Investments	1,038	1		9	(18)	1,048
Property, plant and equipment — net	10,359	53		(5,970)	(19)	4,442
Goodwill	152	—		1,755	(27)	1,907
Identifiable intangible assets — net	1,148	4		2,256	(20)	3,408
Commodity and other derivative contractual assets	73	—		(14)		59
Deferred income taxes	—	320	(5)	730	(21)	1,050
Other noncurrent assets	51	38		158	(22)	247
Total assets	$ 16,875	$ (559)		$ (1,155)		$ 15,161
LIABILITIES AND EQUITY						
Current liabilities:						
Long-term debt due currently	$ 4	$ 5		$ (1)		$ 8
Trade accounts payable	402	145	(6)	3		550
Trade accounts and other payables to affiliates of Predecessor	152	(152)	(6)	—		—
Commodity and other derivative contractual liabilities	125	—		—		125
Margin deposits related to commodity contracts	64	—		—		64
Accrued income taxes	12	12		—		24
Accrued taxes other than income	119	4		—		123
Accrued interest	110	(109)	(7)	—		1
Other current liabilities	243	170	(8)	5		418
Total current liabilities	1,231	75		7		1,313

	October 3, 2016						
	TCEH (Predecessor) (1)	Reorganization Adjustments (2)		Fresh Start Adjustments		Vistra Energy (Successor)
Long-term debt, less amounts due currently	—	3,476	(9)	151	(23)	3,627
Borrowings under debtor-in-possession credit facilities	3,387	(3,387)	(9)	—		—
Liabilities subject to compromise	33,749	(33,749)	(10)	—		—
Commodity and other derivative contractual liabilities	5	—		3		8
Deferred income taxes	256	(256)	(11)	—		—
Tax Receivable Agreement obligation	—	574	(12)	—		574
Asset retirement obligations	809	—		854	(24)	1,663
Other noncurrent liabilities and deferred credits	1,018	117	(13)	(900)	(25)	235
Total liabilities	40,455	(33,150)		115		7,420
Equity:						
Common stock	—	4	(14)	—		4
Additional paid-in-capital	—	7,737	(15)	—		7,737
Accumulated other comprehensive income (loss)	(32)	22		10	(26)	—
Predecessor membership interests	(23,548)	24,828	(16)	(1,280)	(26)	—
Total equity	(23,580)	32,591		(1,270)		7,741
Total liabilities and equity	$ 16,875	$ (559)		$ (1,155)		$ 15,161

(1) Represents the consolidated balance sheet of TCEH as of October 3, 2016.

Reorganization adjustments

(2) Includes the addition of certain assets and liabilities associated with the Contributed EFH Entities. Also includes EFH Corp.'s contribution of liabilities associated with certain employee benefit plans to Vistra Energy.

(3) Net adjustments to cash, which represent distributions made or funding provided to an escrow account, classified as restricted cash, under the Plan of Reorganization, as follows:

Sources (uses):	
Net proceeds from PrefCo preferred stock sale	$ 69
Addition of cash balances from the Contributed EFH Debtors	22
Payments to TCEH first lien creditors, including adequate protection	(486)
Payment to TCEH unsecured creditors (including $73 million to escrow)	(502)
Payment of administrative claims to TCEH creditors	(53)
Payment of legal fees, professional fees and other costs (including $52 million to escrow)	(78)
Net use of cash	$ (1,028)

(4) Increase in restricted cash primarily reflects amounts placed in escrow to satisfy certain secured claims, unsecured claims and professional fee obligations associated with the bankruptcy.

(5) Reflects the deferred income tax impact of the Plan of Reorganization implementation, including cancellation of debts and adjustment of tax-basis for certain assets of PrefCo that issued mandatorily redeemable preferred stock as part of the Spin-Off.

(6) Primarily reflects the reclassification of transmission and distribution service payables to Oncor from payables with affiliates to trade payables with third parties pursuant to the separation of Vistra Energy from EFH Corp. and payment of accrued professional fees and unsecured claimant obligations incurred in conjunction with Emergence.

(7) Primarily reflects the payment of accrued interest and adequate protection to the TCEH first lien creditors on the Effective Date.

(8) Primarily reflects the following:

- Reclassification of $82 million from LSTC related to secured and unsecured claims and $16 million in accrued professional fees from accounts payable to other current liabilities.

- Additional accruals for $23 million of change-in-control obligations and $26 million in success fees triggered by Emergence, $7 million in professional fees, and $28 million of accrued liabilities related to the Contributed EFH Entities.

- Payment of $12 million in professional fees.

(9) Reflects the conversion of the TCEH DIP Roll Facilities of $3.387 billion to the Vistra Operations Credit Facilities at Emergence, the issuance and sale of mandatorily redeemable preferred stock of PrefCo for $70 million, and the obligation related to a corporate office space lease contributed to Vistra Energy pursuant to the Plan of Reorganization. See Note 14 for additional details.

(10) Reflects the elimination of TCEH's liabilities subject to compromise pursuant to the Plan of Reorganization (see Note 5). Liabilities subject to compromise were settled as follows in accordance with the Plan of Reorganization:

Notes, loans and other debt	$	31,668
Accrued interest on notes, loans and other debt		646
Net liability under terminated TCEH interest rate swap and natural gas hedging agreements		1,243
Trade accounts payable and other expected allowed claims		192
Third-party liabilities subject to compromise		33,749
LSTC from the Contributed EFH Entities		8
Total liabilities subject to compromise		33,757
Fair value of equity issued to TCEH first lien creditors		(7,741)
TRA Rights issued to TCEH first lien creditors		(574)
Cash distributed and accruals for TCEH first lien creditors		(377)
Cash distributed for TCEH unsecured claims		(502)
Cash distributed and accruals for TCEH administrative claims		(60)
Settlement of affiliate balances		(99)
Net liabilities of contributed entities and other items		(60)
Gain on extinguishment of LSTC	$	24,344

(11) Reflects the deferred income tax impact of the Plan of Reorganization implementation, including cancellation of debts and adjustment of tax basis of certain assets of PrefCo.

(12) Reflects the estimated present value of the TRA obligation. See Note 10 for further discussion of the TRA obligation valuation assumptions.

(13) Primarily reflects the following:

- Addition of $122 million in liabilities primarily related to benefit plan obligations associated with a pension plan and a health and welfare plan assumed by Vistra Energy pursuant to the Plan of Reorganization. See Note 19 for further discussion of the benefit plan obligations.

- Payment of $7 million in settlements related to split life insurance costs with a prior affiliate entity.

(14) Reflects the issuance of approximately 427,500,000 shares of Vistra Energy common stock, par value of $0.01 per share, to the TCEH first lien creditors. See Note 16.

(15) Reflects adjustments to present Vistra Energy equity value at approximately $7.741 billion based on a reconciliation from the $10.5 billion enterprise value described above under *Reorganization Value* as depicted below:

Enterprise value	$	10,500
Vistra Operations Credit Facility – Initial Term Loan B Facility		(2,871)
Vistra Operations Credit Facility – Term Loan C Facility		(655)
Accrual for post-Emergence claims satisfaction		(181)
Tax Receivable Agreement obligation		(574)
Preferred stock of PrefCo		(70)
Other items		(2)
Cash and cash equivalents		801
Restricted cash		793
Equity value at Emergence	$	7,741
Common stock at par value	$	4
Additional paid-in capital		7,737
Equity value	$	7,741
Shares outstanding at October 3, 2016 (in millions)		427.5
Per share value	$	18.11

(16) Membership Interest impact of Plan of Reorganization are shown below:

Gain on extinguishment of LSTC	$	24,344
Elimination of accumulated other comprehensive income		(22)
Change in control payments		(23)
Professional fees		(33)
Other items		(14)
Pretax gain on reorganization adjustments (Note 5)		24,252
Deferred tax impact of the Plan of Reorganization and Spin-off		576
Total impact to membership interests	$	24,828

Fresh start adjustments

(17) Reflects the reduction of inventory to fair value, including (1) adjustment of fuel inventory to current market prices, and (2) an adjustment to the fair value of materials and supplies inventory primarily used in our lignite/coal-fueled generation assets and related mining operations.

(18) Reflects the $12 million increase in the fair value of certain real property assets and $3 million reduction of the fair value for other investments.

(19) Reflects the change in fair value of property, plant and equipment related primarily to generation and mining assets as detailed below:

Property, Plant and Equipment		**Adjustment**		**Fair Value**
Generation plants and mining assets	$	(6,057)	$	3,698
Land		140		490
Nuclear Fuel		(23)		157
Other equipment		(30)		97
Total	$	(5,970)	$	4,442

We engaged a third-party valuation specialist to assist in preparing the values for our property, plant and equipment. For our generation plants and related mining assets, an income approach was utilized in valuing those assets based on discounted cash flow models that forecast the cash flows of the related assets over their respective useful lives. Significant estimates and assumptions utilized in those models include (1) long-term wholesale power price forecasts, (2) fuel cost forecasts, (3) expected generation volumes based on prevailing forecasts and expected maintenance outages, (4) operations and maintenance costs, (5) capital expenditure forecasts and (6) risk adjusted discount rates based on the cash flows produced by the specific generation asset. The fair value of the generation plants and mining assets is based upon Level 3 inputs utilized in the income approach.

The fair value estimates for land and nuclear fuel utilized the market approach, which included utilizing recent comparable sales information and current market conditions for similarly situated land. Nuclear fuel values were determined by utilizing market pricing information for uranium. The fair value of land and nuclear fuel are based upon Level 3 inputs.

(20) Reflects the adjustment in fair value of $2.256 billion to identifiable intangible assets, including $1.636 billion increase related to retail customer relationships, $270 million increase related to the retail trade name, $190 million increase related to an electricity supply contract, $164 million increase related to retail and wholesale contracts and $4 million decrease related to other intangible assets (see Note 8).

Also reflects the reduction of fair value of $476 million to identifiable intangible liabilities, including a reduction of $525 million related to an electricity supply contract and an increase of $49 million to wholesale contracts.

(21) Reflects the deferred income tax impact of fresh-start adjustments to property, plant, and equipment, inventory, intangibles and debt issuance costs.

(22) Primarily reflects the following:

- Addition of $197 million regulatory asset related to the deficiency of the nuclear decommissioning trust investment as compared to the nuclear generation plant retirement obligation. Pursuant to Texas regulatory provisions, the trust fund for decommissioning our nuclear generation facility is funded by a fee surcharge billed to REPs by Oncor, as a collection agent, and remitted monthly to Vistra Energy.

- Adjustment to remove $26 million of unamortized debt issuance costs to reflect the Vistra Operations Credit Facilities at fair market value.

(23) Reflects the increase in fair value of the Vistra Operations Credit Facilities in the amount of $151 million based on the quoted market prices of the facilities.

(24) Increase in fair value of asset retirement obligation related to the plant retirement, mining and reclamation retirement, and coal combustion residuals. See Note 23 for further discussion of our asset retirement obligations.

(25) Reflects the following:

- Reduction in fair value of unfavorable contracts related to wholesale contracts and a portion of an electricity supply contract in the amount of $476 million. See footnote (20) above for further detail.

- Reduction of $465 million related to reduction in liability that represented excess amounts in the nuclear decommissioning trust above the carrying value of the asset retirement obligation related to our nuclear generation plant decommissioning.

- Increase in fair value of obligations related to leased property in the amount of $29 million.

- Increase in fair value of Pension and OPEB obligations in the amount of $12 million.

(26) Reflects the extinguishment of Predecessor membership interest and accumulated other comprehensive loss per the Plan of Reorganization.

(27) Reflects increase in goodwill balance to present final goodwill as the reorganization value in excess of the identifiable tangible assets, intangible assets, and liabilities at Emergence.

Business enterprise value	$ 10,500
Add: Fair value of liabilities excluded from enterprise value	3,030
Less: Fair value of tangible assets	(8,215)
Less: Fair value of identified intangible assets	(3,408)
Vistra Energy goodwill	$ 1,907

7. REVENUE

The following tables disaggregate our revenue by major source:

	Year Ended December 31, 2018							
	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	CAISO/ Eliminations	Consolidated
Revenue from contracts with customers:								
Retail energy charge in ERCOT	$ 4,426	$ —	$ —	$ —	$ —	$ —	$ —	$ 4,426
Retail energy charge in Northeast/ Midwest	1,123	—	—	—	—	—	—	1,123
Wholesale generation revenue from ISO/RTO	—	1,151	792	544	420	52	167	3,126
Capacity revenue	—	—	369	240	53	6	30	698
Revenue from other wholesale contracts	—	214	29	42	133	—	6	424
Total revenue from contracts with customers	5,549	1,365	1,190	826	606	58	203	9,797
Other revenues:								
Intangible amortization	(26)	(1)	2	(9)	(9)	—	—	(43)
Hedging and other revenues (a)	74	(362)	(62)	(41)	(195)	(31)	7	(610)
Affiliate sales	—	1,632	595	41	318	23	(2,609)	—
Total other revenues	48	1,269	535	(9)	114	(8)	(2,602)	(653)
Total revenues	$ 5,597	$ 2,634	$ 1,725	$ 817	$ 720	$ 50	$ (2,399)	$ 9,144

(a) Includes $380 million of unrealized net losses from mark-to-market valuations of commodity positions. See Note 22 for unrealized net gains (losses) by segment.

Retail Energy Charges

Revenue is recognized when electricity is delivered to our customers in an amount that we expect to invoice for volumes delivered or services provided. Sales tax is excluded from revenue. Payment terms vary from 15 to 45 days from invoice date. Revenue is recognized over-time using the output method based on kilowatt hours delivered. Energy charges are delivered as a series of distinct services and are accounted for as a single performance obligation.

Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Estimated amounts are adjusted when actual usage is known and billed.

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

Wholesale Generation Revenue from ISOs/RTOs

Revenue is recognized when volumes are delivered to the ISO or RTO. Revenue is recognized over time using the output method based on kilowatt hours delivered and cash is settled within 10 days of invoicing. Vistra Energy operates as a market participant within ERCOT, PJM, NYISO, ISO-NE, MISO and CAISO and expects to continue to remain under contract with each ISO or RTO indefinitely. Wholesale generation revenues are delivered as a series of distinct services and are accounted for as a single performance obligation.

Capacity Revenue

We provide capacity to customers through participation in capacity auctions held by the ISO or RTO or through bilateral sales. Generation facilities are awarded auction volumes through the ISO or RTO auction and bilateral sales are based on executed contracts with customers. Capacity revenues consist of revenues billed to a third party at either the market or a negotiated contract price for making installed generation and demand response capacity available in order to satisfy system integrity and reliability requirements. Capacity revenues are recognized when the performance obligation is satisfied ratably over time in accordance with the contracts as our power generation facilities stand ready to deliver power to the customer. Penalties are assessed by the ISO or RTO against generation facilities if the facility is not available during the capacity period. The penalties are recorded as a reduction to revenue.

Revenue from Other Wholesale Contracts

Other wholesale contracts include other revenue activity with the ISOs or RTOs, such as ancillary services, auction revenue, neutrality revenue and revenue from nonaffiliated retail electric providers, municipalities or other wholesale counterparties. Revenue is recognized when the service is performed. Revenue is recognized over time using the output method based on kilowatt hours delivered or other applicable measurements, and cash settles shortly after invoicing. Vistra Energy operates as a market participant within ERCOT, PJM, NYISO, ISO-NE, MISO and CAISO and expects to continue to remain under contract with each ISO or RTO indefinitely. Other wholesale contracts are delivered as a series of distinct services and are accounted for as a single performance obligation.

Other Revenues

Some of our contracts for the sale of electricity meet the definition of a derivative under the accounting standards related to derivative instruments. Revenue from derivative contracts is not considered revenue from contracts with customers under the accounting standards related to revenue. Our revenue from the sale of electricity under derivative contracts, including the impact of unrealized gains or losses on those contracts, are reported in the table above as hedging and other revenues. We have classified all sales to affiliates that are eliminated in consolidation as other revenues in the table above.

Contract and Other Customer Acquisition Costs

We defer costs to acquire retail contracts and amortize these costs over the expected life of the contract. The expected life of a retail contract is calculated using historical attrition rates, which we believe to be an accurate indicator of future attrition rates. The deferred acquisition and contract cost balance as of December 31, 2018 and January 1, 2018 was $38 million and $22 million, respectively. The amortization related to these costs during the year ended December 31, 2018 totaled $10 million, recorded as selling, general and administrative expenses, and $7 million, recorded as a reduction to operating revenues in the statement of consolidated income (loss).

Practical Expedients

The vast majority of revenues are recognized under the right to invoice practical expedient, which allows us to recognize revenue in the same amount that we have a right to invoice our customers. Unbilled revenues are recorded based on the volumes delivered and services provided to the customers at the end of the period, using the right to invoice practical expedient. We do not disclose the value of unsatisfied performance obligations for contracts with variable consideration for which we recognize revenue using the right to invoice practical expedient. We use the portfolio approach in evaluating similar customer contracts with similar performance obligations. Sales taxes are not included in revenue.

Performance Obligations

As of December 31, 2018, we have future performance obligations that are unsatisfied, or partially unsatisfied, relating to capacity auction volumes awarded through capacity auctions held by the ISO or RTO or through bilateral sales. Therefore, an obligation exists as of the date of the results of the respective ISO or RTO capacity auction or the contract execution date for bilateral customers. The transaction price is also set by the results of the capacity auction and/or executed contract. These obligations total $968 million, $718 million, $720 million, $342 million and $38 million that will be recognized in the years ending December 31, 2019, 2020, 2021, 2022 and 2023, respectively, and $65 million thereafter. Capacity revenues are recognized as capacity services are provided to the related ISOs or RTOs or bilateral counterparties.

Accounts Receivable

The following table presents trade accounts receivable (net of allowance for uncollectible accounts) relating to both contracts with customers and other activities:

	December 31, 2018
Trade accounts receivable from contracts with customers — net	$ 951
Other trade accounts receivable — net	136
Total trade accounts receivable — net	$ 1,087

8. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS AND LIABILITIES

Goodwill

The carrying value of goodwill totaled $2.068 billion and $1.907 billion at December 31, 2018 and 2017, respectively. Of the total goodwill, $161 million arose in connection with the Merger and is recorded at the corporate and other level non-segment operations pending completion of the purchase price allocation in the first quarter of 2019, at which time goodwill will be allocated to reporting units. The remaining $1.907 billion arose in connection with our application of fresh start reporting at Emergence and was allocated entirely to our ERCOT Retail reporting unit. There have been no impairments of Goodwill since Emergence. Of the goodwill recorded at Emergence, $1.686 billion is deductible for tax purposes over 15 years on a straight-line basis.

Goodwill and intangible assets with indefinite useful lives are required to be evaluated for impairment at least annually or whenever events or changes in circumstances indicate an impairment may exist. As of the Effective Date, we have selected October 1 as our annual goodwill test date. On the most recent goodwill testing date, we applied qualitative factors and determined that it was more likely than not that the fair value of our ERCOT Retail reporting unit exceeded its carrying value at October 1, 2018. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, cost factors, customer attrition, interest rates and changes in reporting unit book value.

Identifiable Intangible Assets and Liabilities

Identifiable intangible assets are comprised of the following:

	December 31, 2018			December 31, 2017		
Identifiable Intangible Asset	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**
Retail customer relationship	$ 1,680	$ 876	$ 804	$ 1,648	$ 572	$ 1,076
Software and other technology-related assets	270	105	165	183	47	136
Retail and wholesale contracts	316	138	178	154	87	67
Contractual service agreements	70	—	70	—	—	—
Other identifiable intangible assets (a)	42	15	27	33	11	22
Total identifiable intangible assets subject to amortization	$ 2,378	$ 1,134	1,244	$ 2,018	$ 717	1,301
Retail trade names (not subject to amortization)			1,245			1,225
Mineral interests (not currently subject to amortization)			4			4
Total identifiable intangible assets			$ 2,493			$ 2,530

(a) Includes mining development costs and environmental allowances and credits.

Identifiable intangible liabilities are comprised of the following:

	Year Ended December 31,	
Identifiable Intangible Liability	**2018**	**2017**
Contractual service agreements	$ 136	$ —
Purchase and sale contracts	195	36
Environmental allowances	$ 70	$ —
Total identifiable intangible liabilities	$ 401	$ 36

Amortization expense related to finite-lived identifiable intangible assets and liabilities (including the classification in the statements of consolidated income (loss)) consisted of:

			Successor			Predecessor
			Year Ended December 31,			
Identifiable Intangible Assets and Liabilities	Statements of Consolidated Income (Loss) Line	Remaining useful lives of identifiable intangible assets at December 31, 2018 (weighted average in years)	2018	2017	Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
Retail customer relationship	Depreciation and amortization	4	$ 304	$ 420	$ 152	$ 9
Software and other technology-related assets	Depreciation and amortization	3	62	38	9	44
Retail and wholesale contracts/purchase and sale contracts	Operating revenues/fuel, purchased power costs and delivery fees	4	43	59	38	—
Other identifiable intangible assets	Operating revenues/fuel, purchased power costs and delivery fees/depreciation and amortization	4	58	15	4	6
Total amortization expense (a)			$ 467	$ 532	$ 203	$ 59

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(a) Amounts recorded in depreciation and amortization totaled $370 million, $463 million, $162 million and $58 million for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively. Excludes contractual services agreements.

Following is a description of the separately identifiable intangible assets. In connection with fresh start reporting or the Merger (see Notes 2 and 6), the intangible assets were adjusted based on their estimated fair value as of the Effective Date or the Merger Date, based on observable prices or estimates of fair value using valuation models. The purchase price allocation is substantially complete, but is dependent upon final valuation determinations, which may materially change from our current estimates. We currently expect the final purchase price allocation will be completed no later than the first quarter of 2019.

- *Retail customer relationship* – Retail customer relationship intangible asset represents the fair value of our non-contracted retail customer base, including residential and business customers, and is being amortized using an accelerated method based on historical customer attrition rates and reflecting the expected pattern in which economic benefits are realized over their estimated useful life.

- *Retail trade names* – Our retail trade name intangible asset represents the fair value of the TXU Energy™, 4Change Energy™, Homefield and Dynegy Energy Services trade names, and was determined to be an indefinite-lived asset not subject to amortization. This intangible asset is evaluated for impairment at least annually in accordance with accounting guidance related to goodwill and other indefinite-lived intangible assets. Significant assumptions included within the development of the fair value estimate include estimated gross margins for future periods and implied royalty rates. On the most recent testing date, we determined that it was more likely than not that the fair value of our retail trade name intangible asset exceeded its carrying value at October 1, 2018.

- *Retail and wholesale contracts/purchase and sale contracts* – These intangible assets represent the value of various retail and wholesale contracts and purchase and sale contracts. The contracts were identified as either assets or liabilities based on the respective fair values as of the Effective Date or the Merger Date utilizing prevailing market prices for commodities or services compared to the fixed prices contained in these agreements. The intangible assets or liabilities are being amortized in relation to the economic terms of the related contracts.

- *Contractual service agreements* – Our acquired contractual service agreements represent the estimated fair value of favorable or unfavorable contract obligations with respect to long-term plant maintenance agreements, rail transportation agreements and rail car leases, and are being amortized based on the expected usage of the service agreements over the contract terms. The majority of the plant maintenance services relate to capital improvements and the related amortization of the plant maintenance agreements is recorded to property, plant and equipment. Amortization of rail transportation and rail car lease agreements is recorded to fuel, purchased power costs and delivery fees.

Estimated Amortization of Identifiable Intangible Assets and Liabilities

As of December 31, 2018, the estimated aggregate amortization expense of identifiable intangible assets and liabilities for each of the next five fiscal years is as shown below.

Year	Estimated Amortization Expense
2019	$ 299
2020	$ 201
2021	$ 154
2022	$ 91
2023	$ 67

9. INCOME TAXES

Successor

Vistra Energy files a United States federal income tax return that includes the results of its consolidated subsidiaries. Vistra Energy is the corporate parent of the Vistra Energy consolidated group. Pursuant to applicable United States Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group.

Predecessor

Prior to the Effective Date, EFH Corp. was the corporate parent of the EFH Corp. consolidated group, while TCEH and the Contributed EFH Debtors were classified as disregarded entities for U.S. federal income tax purposes. For the 2016 tax year (through the period until the Effective Date) EFH Corp. filed a U.S. federal income tax return in October 2017 that included the results of TCEH and the EFH Contributed Debtors. Pursuant to applicable U.S. Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group.

Prior to the Effective Date, EFH Corp. and certain of its subsidiaries (including TCEH and the Contributed EFH Debtors) were parties to a Federal and State Income Tax Allocation Agreement, which provided, among other things, that any corporate member or disregarded entity in the EFH Corp. group was required to make payments to EFH Corp. in an amount calculated to approximate the amount of tax liability such entity would have owed if it filed a separate corporate tax return. Pursuant to the Plan of Reorganization, the TCEH Debtors and the Contributed EFH Debtors rejected this agreement on the Effective Date. See Note 5 for a discussion of the Tax Matters Agreement that was entered into on the Effective Date between EFH Corp. and Vistra Energy. Additionally, since the date of the Settlement Agreement, no further cash payments among the Debtors were made in respect of federal income taxes. The Settlement Agreement did not alter the allocation and payment for state income taxes, which continued to be settled prior to the Effective Date.

Income Tax Expense (Benefit)

The components of our income tax expense (benefit) are as follows:

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Current:				
U.S. Federal	$ (13)	$ 72	$ —	$ (6)
State	30	14	6	9
Total current	17	86	6	3
Deferred:				
U.S. Federal	(8)	417	(75)	(1,234)
State	(54)	1	(1)	(36)
Total deferred	(62)	418	(76)	(1,270)
Total	$ (45)	$ 504	$ (70)	$ (1,267)

Reconciliation of income taxes computed at the U.S. federal statutory rate to income tax expense (benefit) recorded:

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Income (loss) before income taxes	$ (101)	$ 250	$ (233)	$ 21,584
US federal statutory rate	21%	35%	35%	35 %
Income taxes at the U.S. federal statutory rate	(20)	88	(82)	7,554
Nondeductible TRA accretion	8	(80)	5	—
State tax, net of federal benefit	22	13	3	(21)
Impacts of tax reform legislation on deferred taxes	—	451	—	—
Return to provision adjustment	(12)	19	—	—
Remeasurement of historical Vistra Energy deferred taxes for expanded state footprint	(54)	—	—	—
Effect of refundable minimum tax credits no longer subject to sequestration	(15)	—	—	—
Nondeductible compensation	8	—	—	—
Nondeductible transaction costs	3	—	—	—
Equity awards	(3)	—	—	—
Nondeductible debt restructuring costs	—	—	2	38
Nondeductible interest expense	—	—	—	12
Nontaxable gain on extinguishment of LSTC	—	—	—	(8,593)
Valuation allowance on state NOLs	20	—	—	(210)
Other	(2)	13	2	(47)
Income tax expense (benefit)	$ (45)	$ 504	$ (70)	$ (1,267)
Effective tax rate	44.6%	201.6%	30.0%	(5.9)%

Deferred Income Tax Balances

Deferred income taxes provided for temporary differences based on tax laws in effect at December 31, 2018 and 2017 are as follows:

	December 31,	
	2018	2017
Noncurrent Deferred Income Tax Assets		
Tax credit carryforwards	$ 76	$ —
Loss carryforwards	958	—
Property, plant and equipment	—	520
Identifiable intangible assets	184	81
Long-term debt	188	20
Employee benefit obligations	109	56
Commodity contracts and interest rate swaps	212	25
Other	40	8
Total deferred tax assets	$ 1,767	$ 710
Noncurrent Deferred Income Tax Liabilities		
Property, plant and equipment	406	—
Total deferred tax liabilities	406	—
Valuation allowance	35	—
Net Deferred Income Tax Asset	$ 1,326	$ 710

At December 31, 2018, we had total deferred tax assets of approximately $1.326 billion that were substantially comprised of book and tax basis differences related to our generation and mining property, plant and equipment, as well as federal and state net operating loss (NOL) carryforwards. Our deferred tax assets were significantly impacted by the Merger. As of December 31, 2018, we assessed the need for a valuation allowance related to our deferred tax asset and considered both positive and negative evidence related to the likelihood of realization of the deferred tax assets. In connection with our analysis, we concluded that it is more likely than not that the federal deferred tax assets will be fully utilized by future taxable income, and thus no valuation allowance was required. We recognized a partial valuation allowance of $20 million on the net operating loss carryforwards related to Illinois due to forecasted expiration. In addition, in our purchase price allocation we recognized a valuation allowance of $15 million for separate state jurisdictions.

At December 31, 2018, we had $3.560 billion pre-tax net operating loss (NOL) carryforwards for federal income tax purposes that will begin to expire in 2032. At December 31, 2018, we had $255 million alternative minimum tax (AMT) credits refundable through the TCJA available.

The income tax effects of the components included in accumulated other comprehensive income totaled a net deferred tax asset of $2 million at December 31, 2018 and a net deferred tax liability of $6 million at December 31, 2017.

Liability for Uncertain Tax Positions

Accounting guidance related to uncertain tax positions requires that all tax positions subject to uncertainty be reviewed and assessed with recognition and measurement of the tax benefit based on a "more-likely-than-not" standard with respect to the ultimate outcome, regardless of whether this assessment is favorable or unfavorable.

We classify interest and penalties related to uncertain tax positions as current income tax expense. The amounts were immaterial in the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016. The following table summarizes the changes to the uncertain tax positions, reported in accumulated deferred income taxes and other current liabilities in the consolidated balance sheets, during the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016:

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Balance at beginning of period, excluding interest and penalties	$ —	$ —	$ —	$ 36
Additions allocated in the Merger	39	—	—	—
Reductions based on tax positions related to prior years	—	—	—	(1)
Settlements with taxing authorities	—	—	—	(35)
Balance at end of period, excluding interest and penalties	$ 39	$ —	$ —	$ —

Successor — Vistra Energy and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and are expected to be subject to examinations by the IRS and other taxing authorities. Vistra Energy is not currently under audit by the IRS for any period. Uncertain tax positions totaling $39 million at December 31, 2018 arose in connection with the Merger and our assessment of the assumed liabilities is not complete as discussed in Note 2. We had no uncertain tax positions at December 31, 2017.

Predecessor — EFH Corp. and its subsidiaries file or have filed income tax returns in U.S. Federal, state and foreign jurisdictions and are subject to examinations by the IRS and other taxing authorities. EFH Corp. filed a request for prompt determination of its 2016 tax return with the IRS in October 2017, and such return was accepted for expedited review in December 2017. As a result, the IRS audit of EFH Corp.'s 2016 tax return concluded in April 2018. Texas franchise and margin tax return examinations have been completed.

In September 2016, EFH Corp. entered into a settlement agreement with the Texas Comptroller of Public Accounts (Comptroller) whereby the Comptroller agreed to release all claims and liabilities related to the EFH Corp. consolidated group's state taxes, including sales tax, gross receipts utility tax, franchise tax and direct pay tax, through the agreement date, in exchange for a release of all refund claims and a one-time payment of $12 million. This settlement was entered and approved by the Bankruptcy Court in September 2016. As a result of the settlement, our Predecessor reduced the liability for uncertain tax positions by $27 million.

In July 2016, EFH Corp. executed a Revenue Agent Report (RAR) with the IRS for the 2010 through 2013 tax years. As a result of the RAR, our Predecessor reduced the liability for uncertain tax positions by $1 million, resulting in a reclassification to the accumulated deferred income tax liability. Total cash payment to be assessed by the IRS for tax years 2010 through 2013, but not expected to be paid during the pendency of the Chapter 11 Cases of the EFH Debtors, is approximately $15 million, plus any interest that may be assessed.

In March 2016, EFH Corp. signed a RAR with the IRS for the 2014 tax year. No financial statement impacts resulted from the signing of the 2014 RAR.

Tax Matters Agreement

On the Effective Date, we entered into the Tax Matters Agreement with EFH Corp. whereby the parties have agreed to take certain actions and refrain from taking certain actions in order to preserve the intended tax treatment of the Spin-Off and to indemnify the other parties to the extent a breach of such agreement results in additional taxes to the other parties.

Among other things, the Tax Matters Agreement allocates the responsibility for taxes for periods prior to the Spin-Off between EFH Corp. and us. For periods prior to the Spin-Off: (a) Vistra Energy is generally required to reimburse EFH Corp. with respect to any taxes paid by EFH Corp. that are attributable to us and (b) EFH Corp. is generally required to reimburse us with respect to any taxes paid by us that are attributable to EFH Corp.

We are also required to indemnify EFH Corp. against taxes, under certain circumstance, if the IRS or another taxing authority successfully challenges the amount of gain relating to the PrefCo Preferred Stock Sale or the amount or allowance of EFH Corp.'s net operating loss deductions.

Subject to certain exceptions, the Tax Matters Agreement prohibits us from taking certain actions that could reasonably be expected to undermine the intended tax treatment of the Spin-Off or to jeopardize the conclusions of the private letter ruling we obtained from the IRS or opinions of counsel received by us or EFH Corp., in each case, in connection with the Spin-Off. Certain of these restrictions apply for two years after the Spin-Off.

Under the Tax Matters Agreement, we may engage in an otherwise restricted action if (a) we obtain written consent from EFH Corp., (b) such action or transaction is described in or otherwise consistent with the facts in the private letter ruling we obtained from the IRS in connection with the Spin-Off, (c) we obtain a supplemental private letter ruling from the IRS, or (d) we obtain an unqualified opinion of a nationally recognized law or accounting firm that is reasonably acceptable to EFH Corp. that the action will not affect the intended tax treatment of the Spin-Off.

10. TAX RECEIVABLE AGREEMENT OBLIGATION

On the Effective Date, Vistra Energy entered into a tax receivable agreement (the TRA) with a transfer agent on behalf of certain former first lien creditors of our Predecessor. The TRA generally provides for the payment by us to holders of TRA Rights of 85% of the amount of cash savings, if any, in U.S. federal and state income tax that we realize in periods after Emergence as a result of (a) certain transactions consummated pursuant to the Plan of Reorganization (including the step-up in tax basis in our assets resulting from the PrefCo Preferred Stock Sale), (b) the tax basis of all assets acquired in connection with the acquisition of two CCGT natural gas-fueled generation facilities in April 2016 and (c) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA, plus interest accruing from the due date of the applicable tax return.

Pursuant to the TRA, we issued the TRA Rights for the benefit of the first lien secured creditors of our Predecessor entitled to receive such TRA Rights under the Plan of Reorganization. Such TRA Rights are entitled to certain registration rights more fully described in the Registration Rights Agreement (see Note 21).

During the year ended December 31, 2018, we recorded an increase to the carrying value of the TRA obligation totaling approximately $14 million as a result of changes in the timing of estimated payments and new multistate tax impacts resulting from the Merger. During the year ended December 31, 2017, we recorded a decrease to the carrying value of the TRA obligation totaling $295 million related to changes in the timing of estimated payments resulting from changes in certain tax assumptions including (a) the impacts of Luminant's plan to retire its Monticello, Sandow 4, Sandow 5 and Big Brown generation plants and the impacts of the Alcoa settlement (see Note 4), (b) investment tax credits we expect to receive related to the Upton 2 solar development project (see Note 3), (c) assets acquired in the Odessa Acquisition (see Note 3) and (d) the impacts of other forecasted tax amounts.

The following table summarizes the changes to the TRA obligation, reported as other current liabilities and Tax Receivable Agreement obligation in our consolidated balance sheets, for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016:

	Successor		
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016
	2018	2017	
TRA obligation at the beginning of the period	$ 357	$ 596	$ 574
Accretion expense	65	82	22
Payments	(16)	(26)	—
Changes in tax assumptions impacting timing of payments	14	(62)	—
Revaluation due to tax reform legislation	—	(233)	—
TRA obligation at the end of the period	420	357	596
Less amounts due currently	—	(24)	—
Noncurrent TRA obligation at the end of the period	$ 420	$ 333	$ 596

As of December 31, 2018, the estimated carrying value of the TRA obligation totaled $420 million, which represents the discounted amount of projected payments under the TRA. The projected payments are based on certain assumptions, including but not limited to (a) the federal corporate income tax rate of 21% for 2018 and 35% for 2017 and 2016, (b) estimates of our taxable income in the current and future years and (c) additional states that Vistra Energy now operates in, including the relevant tax rate and apportionment factor for each state. Our taxable income takes into consideration the current federal tax code, various relevant state tax laws and reflects our current estimates of future results of the business. These assumptions are subject to change, and those changes could have a material impact on the carrying value of the TRA obligation. As of December 31, 2018, the aggregate amount of undiscounted federal and state payments under the TRA is estimated to be approximately $1.4 billion, with more than half of such amount expected to be attributable to the first 15 tax years following Emergence, and the final payment expected to be made approximately 40 years following Emergence (if the TRA is not terminated earlier pursuant to its terms).

The carrying value of the obligation is being accreted to the amount of the gross expected obligation using the effective interest method. Changes in the amount of this obligation resulting from changes to either the timing or amount of TRA payments are recognized in the period of change and measured using the discount rate inherent in the initial fair value of the obligation. During the year ended December 31, 2018, the Impacts of Tax Receivable Agreement on the consolidated income (loss) totaled $79 million, which represents the changes to the carrying value of the TRA obligation discussed above and accretion expense totaling $65 million. During the year ended December 31, 2017, the Impacts of Tax Receivable Agreement on the statement of consolidated income (loss) totaled $213 million, which represents the reduction to the carrying value of the TRA obligation discussed above partially offset by accretion expense totaling $82 million. During the period from October 3, 2016 through December 31, 2016, the Impacts of the Tax Receivable Agreement represents accretion expense totaling $22 million.

11. INTEREST EXPENSE AND RELATED CHARGES

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Interest paid/accrued post-Emergence	$ 537	$ 213	$ 51	$ —
Interest paid/accrued on debtor-in-possession financing	—	—	—	76
Adequate protection amounts paid/accrued	—	—	—	977
Unrealized mark-to-market net (gains) losses on interest rate swaps	5	(29)	11	—
Amortization of debt issuance costs, discounts and premiums	—	4	(1)	4
Debt extinguishment loss	27	—	—	—
Capitalized interest	(12)	(7)	(3)	(9)
Other	15	12	2	1
Total interest expense and related charges	$ 572	$ 193	$ 60	$ 1,049

Successor

The weighted average interest rate applicable to the Vistra Operations Credit Facilities, considering the interest rate swaps discussed in Note 14, was 4.24% and 4.38% at December 31, 2018 and 2017, respectively.

Predecessor

Interest expense for the Predecessor period from January 1, 2016 through October 2, 2016 reflects interest paid and accrued on debtor-in-possession financing (see Note 14) and adequate protection amounts paid and accrued, as approved by the Bankruptcy Court in June 2014 for the benefit of secured creditors in exchange for their consent to the senior secured, super-priority liens contained in the DIP Facility. The interest rate applicable to the adequate protection amounts paid/accrued for the Predecessor period from January 1, 2016 through October 2, 2016 was 4.95%.

The Bankruptcy Code generally restricts payment of interest on pre-petition debt, subject to certain exceptions. Other than amounts ordered or approved by the Bankruptcy Court, effective on the Petition Date, our Predecessor discontinued recording interest expense on outstanding pre-petition debt classified as LSTC. The table below shows contractual interest amounts, which are amounts due under the contractual terms of the outstanding debt, including debt subject to compromise during the Chapter 11 Cases. Interest expense reported in our statements of consolidated income (loss) does not include contractual interest on pre-petition debt classified as LSTC totaling $640 million for the Predecessor period from January 1, 2016 through October 2, 2016, which had been stayed by the Bankruptcy Court effective on the Petition Date. Adequate protection amounts paid/accrued presented below excludes interest paid/accrued on TCEH first-lien interest rate and commodity hedge claims totaling $47 million for the Predecessor period from January 1, 2016 through October 2, 2016, as such amounts are not included in contractual interest amounts below.

	Predecessor
	Period from January 1, 2016 through October 2, 2016
Contractual interest on debt classified as LSTC	$ 1,570
Adequate protection amounts paid/accrued	930
Contractual interest on debt classified as LSTC not paid/accrued	$ 640

12. EARNINGS PER SHARE

Basic earnings per share available to common shareholders are based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated using the treasury stock method and includes the effect of all potential issuances of common shares under stock-based incentive compensation arrangements.

	Successor		
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016
Net loss attributable to common stock — basic (a)	$ (54)	$ (254)	$ (163)
Weighted average shares of common stock outstanding — basic	504,954,371	427,761,460	427,560,620
Net loss per weighted average share of common stock outstanding — basic	$ (0.11)	$ (0.59)	$ (0.38)
Weighted average shares of common stock outstanding — diluted	504,954,371	427,761,460	427,560,620
Net loss per weighted average share of common stock outstanding — diluted	$ (0.11)	$ (0.59)	$ (0.38)

(a) The minimum settlement amount of tangible equity units, or 15,056,260 shares, are considered to be outstanding and are included in the computation of basic net income per share (see Note 16).

Stock-based incentive compensation plan awards excluded from the calculation of diluted earnings per share because the effect would have been antidilutive totaled 14,165,813, 3,642,844 and 7,332,789 shares for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016, respectively.

13. ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

TXU Energy Receivables Company LLC (RecCo), an indirect subsidiary of Vistra Energy, has an accounts receivable financing facility (Receivables Facility) provided by issuers of asset-backed commercial paper and commercial banks (Purchasers). The Receivables Facility is currently scheduled to terminate in August 2019, unless termination occurs earlier in accordance with the terms of the Receivables Facility. The Receivables Facility provides RecCo with the ability to borrow up to $350 million.

Under the Receivables Facility, TXU Energy may sell or contribute, on an ongoing basis and without recourse, its accounts receivable to its special purpose subsidiary, RecCo, a consolidated, wholly owned, bankruptcy-remote, direct subsidiary of TXU Energy. RecCo, in turn, is subject to certain conditions, and may, from time to time, sell an undivided interest in all the receivables to the Purchasers, and its assets and credit are not available to satisfy the debts and obligations of any person, including affiliates of RecCo. Amounts funded by the Purchasers to RecCo are reflected as short-term borrowings on the consolidated balance sheets. Proceeds and repayments under the Receivables Facility are reflected as cash flows from financing activities in our statements of consolidated cash flows. Receivables transferred to the Purchasers remain on Vistra Energy's balance sheet and Vistra Energy reflects a liability equal to the amount advanced by the Purchasers. The Company records interest expense on amounts advanced. TXU Energy continues to service, administer and collect the trade receivables on behalf of RecCo and the Purchasers, as applicable.

As of December 31, 2018, the receivables facility totaled $339 million and is supported by $477 million of RecCo gross receivables.

14. LONG-TERM DEBT

Successor

Amounts in the table below represent the categories of long-term debt obligations incurred by the Successor.

	December 31, 2018	December 31, 2017
Vistra Operations Credit Facilities	$ 5,813	$ 4,311
Vistra Operations 5.500% Senior Notes, due September 1, 2026	1,000	—
Vistra Energy Senior Notes:		
7.375% Senior Notes, due November 1, 2022	1,707	—
5.875% Senior Notes, due June 1, 2023	500	—
7.625% Senior Notes, due November 1, 2024	1,147	—
8.034% Senior Notes, due February 2, 2024	25	—
8.000% Senior Notes, due January 15, 2025	81	—
8.125% Senior Notes, due January 30, 2026	166	—
Total Vistra Energy Senior Notes	3,626	—
Other:		
7.000% Amortizing Notes, due July 1, 2019	24	—
Forward Capacity Agreements	236	—
Equipment Financing Agreements	120	—
Mandatorily redeemable subsidiary preferred stock (a)	70	70
8.82% Building Financing due semiannually through February 11, 2022 (b)	21	27
Total other long-term debt	471	97
Unamortized debt premiums, discounts and issuance costs (c)	155	15
Total long-term debt including amounts due currently	11,065	4,423
Less amounts due currently	(191)	(44)
Total long-term debt less amounts due currently	$ 10,874	$ 4,379

(a) Shares of mandatorily redeemable preferred stock in PrefCo issued as part of the spin-off of Vistra Energy from EFH Corp. (see Note 5). This subsidiary preferred stock is accounted for as a debt instrument under relevant accounting guidance.
(b) Obligation related to a corporate office space capital lease transferred to Vistra Energy pursuant to the Plan of Reorganization. This obligation will be funded by amounts held in an escrow account that is reflected in other noncurrent assets in our consolidated balance sheets.
(c) Includes impact of recording debt assumed in the Merger at fair value.

Vistra Operations Credit Facilities

At December 31, 2018, the Vistra Operations Credit Facilities consisted of up to $8.313 billion in senior secured, first lien revolving credit commitments and outstanding term loans, consisting of revolving credit commitments of up to $2.5 billion, including a $2.3 billion letter of credit sub-facility (Revolving Credit Facility) and term loans of $2.793 billion (Term Loan B-1 Facility), $980 million (Term Loan B-2 Facility) and $2.040 billion (Term Loan B-3 Facility, and together with the Term Loan B-1 Facility and the Term Loan B-2 Facility, the Term Loan B Facility).

These amounts reflect an amendment to the Vistra Operations Credit Facilities in June 2018 whereby we incurred $2.050 billion of borrowings under the new Term Loan B-3 Facility and obtained $1.640 billion of incremental Revolving Credit Facility commitments. The letter of credit sub-facility was also increased by $1.585 billion. The maturity date of the Revolving Credit Facility was extended from August 4, 2021 to June 14, 2023. As discussed below, the proceeds from the Term Loan B-3 Facility were used to repay borrowings under the credit agreement that Vistra Energy assumed from Dynegy in connection with the Merger. Additionally, letter of credit term loans totaling $500 million (Term Loan C Facility) were repaid using $500 million of cash from collateral accounts used to backstop letters of credit. Fees and expenses related to the amendment to the Vistra Operations Credit Facilities totaled $42 million in the year ended December 31, 2018, of which $23 million was recorded as interest expense and other charges on the statements of consolidated income (loss), $9 million was capitalized as a reduction in the carrying amount of the debt and $10 million was capitalized as a noncurrent asset.

The Vistra Operations Credit Facilities and related available capacity at December 31, 2018 are presented below.

		December 31, 2018		
Vistra Operations Credit Facilities	**Maturity Date**	**Facility Limit**	**Cash Borrowings**	**Available Capacity**
Revolving Credit Facility (a)	June 14, 2023	$ 2,500	$ —	$ 1,135
Term Loan B-1 Facility	August 4, 2023	2,793	2,793	—
Term Loan B-2 Facility	December 14, 2023	980	980	—
Term Loan B-3 Facility	December 31, 2025	2,040	2,040	—
Total Vistra Operations Credit Facilities		$ 8,313	$ 5,813	$ 1,135

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(a) Facility to be used for general corporate purposes. Facility includes a $2.3 billion letter of credit sub-facility, of which $1.365 billion of letters of credit were outstanding at December 31, 2018 and which reduce our available capacity.

In February and June 2018, certain pricing terms for the Vistra Operations Credit Facilities were amended. We accounted for these transactions as modifications of debt. At December 31, 2018, cash borrowings under the Revolving Credit Facility would bear interest based on applicable LIBOR rates, plus a fixed spread of 1.75%, and there were no outstanding borrowings. Letters of credit issued under the Revolving Credit Facility bear interest of 1.75%. Amounts borrowed under the Term Loan B-1, B-2 and B-3 Facilities bear interest based on applicable LIBOR rates plus fixed spreads of 2.00%, 2.25% and 2.00%, respectively. At December 31, 2018, the weighted average interest rates before taking into consideration interest rate swaps on outstanding borrowings was 4.52%, 4.77% and 4.47% under the Term Loan B-1, B-2 and B-3 Facilities, respectively. The Vistra Operations Credit Facilities also provide for certain additional fees payable to the agents and lenders, including fronting fees with respect to outstanding letters of credit and availability fees payable with respect to any unused portion of the available Revolving Credit Facility.

Obligations under the Vistra Operations Credit Facilities are secured by a lien covering substantially all of Vistra Operations' (and its subsidiaries') consolidated assets, rights and properties, subject to certain exceptions set forth in the Vistra Operations Credit Facilities, provided that the amount of loans outstanding under the Vistra Operations Credit Facilities that may be secured by a lien covering certain principal properties of the Company is expressly limited by the terms of the Vistra Operations Credit Facilities.

The Vistra Operations Credit Facilities also permit certain hedging agreements to be secured on a pari-passu basis with the Vistra Operations Credit Facilities in the event those hedging agreements met certain criteria set forth in the Vistra Operations Credit Facilities.

The Vistra Operations Credit Facilities provide for affirmative and negative covenants applicable to Vistra Operations (and its restricted subsidiaries), including affirmative covenants requiring it to provide financial and other information to the agents under the Vistra Operations Credit Facilities and to not change its lines of business, and negative covenants restricting Vistra Operations' (and its restricted subsidiaries') ability to incur additional indebtedness, make investments, dispose of assets, pay dividends, grant liens or take certain other actions, in each case, except as permitted in the Vistra Operations Credit Facilities. Vistra Operations' ability to borrow under the Vistra Operations Credit Facilities is subject to the satisfaction of certain customary conditions precedent set forth therein.

The Vistra Operations Credit Facilities provide for certain customary events of default, including events of default resulting from non-payment of principal, interest or fees when due, material breaches of representations and warranties, material breaches of covenants in the Vistra Operations Credit Facilities or ancillary loan documents, cross-defaults under other agreements or instruments and the entry of material judgments against Vistra Operations. Solely with respect to the Revolving Credit Facility, and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and issued revolving letters of credit (in excess of $300 million) exceed 30% of the revolving commitments), the agreement includes a covenant that requires the consolidated first lien net leverage ratio, which is based on the ratio of net first lien debt compared to an EBITDA calculation defined under the terms of the facilities, not to exceed 4.25 to 1.00. As of December 31, 2018, we were in compliance with this financial covenant. Upon the existence of an event of default, the Vistra Operations Credit Facilities provide that all principal, interest and other amounts due thereunder will become immediately due and payable, either automatically or at the election of specified lenders.

Interest Rate Swaps — Effective January 2017, we entered into $3.0 billion notional amount of interest rate swaps to hedge a portion of our exposure to our variable rate debt. The interest rate swaps expire in July 2023. In May and June 2018, we entered into $3.0 billion notional amount of interest rate swaps that become effective in July 2023 and expire in July 2026.

In June 2018, we completed the novation of $1.959 billion of Vistra Energy (legacy Dynegy) interest rate swaps to Vistra Operations. In June 2018, $238 million of these interest rate swaps expired. The remaining interest rate swaps expire between March 2019 and February 2024.

The interest rate swaps effectively fix the interest rates between 4.13% and 4.38% on $4.717 billion of our variable rate debt. The interest rate swaps that become effective in July 2023 and expire in July 2026 effectively fix the interest rates between 4.97% and 5.04% on $3.0 billion of our variable rate debt during the period. The interest rate swaps are secured by a first lien secured interest on a pari passu basis with the Vistra Operations Credit Facilities.

Alternative Letter of Credit Facility

In December 2018, we entered into an alternative letter of credit facility with a facility limit of approximately $193 million at February 25, 2019. The facility became effective in January 2019.

Vistra Energy (legacy Dynegy) Credit Agreement

On the Merger Date, Vistra Energy assumed the obligations under Dynegy's $3.563 billion credit agreement consisting of a $2.018 billion senior secured term loan facility due 2024 and a $1.545 billion senior secured revolving credit facility. As of the Merger Date, there were no cash borrowings and $656 million of letters of credit outstanding under the senior secured revolving credit facility. On April 23, 2018, $70 million of the senior secured revolving credit facility matured. In June 2018, the $2.018 billion senior secured term loan facility due 2024 was repaid using proceeds from the Term Loan B-3 Facility. In addition, all letters of credit outstanding under the senior secured revolving credit facility were replaced with letters of credit under the amended Vistra Operations Credit Facilities discussed above, and the revolving credit facility assumed from Dynegy in connection with the Merger was paid off in full and terminated.

Vistra Operations Senior Notes

In February 2019, Vistra Operations issued and sold $1.3 billion aggregate principal amount of 5.625% senior notes due 2027 in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act of 1933, as amended (the 2019 Notes Offering). The senior notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and J.P. Morgan Securities LLC, as representative of the several initial purchasers. Net proceeds from the 2019 Notes Offering totaling approximately $1.287 billion, together with cash on hand, were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with (i) the 2019 Tender Offer described below, (ii) the redemption of approximately $35 million aggregate principal amount of our 7.375% senior notes due 2022 and (iii) the redemption of approximately $25 million aggregate principal amount of our outstanding 8.034% senior notes due 2024. The 5.625% senior notes mature in February 2027, with interest payable in cash semiannually in arrears on February 15 and August 15 beginning August 15, 2019.

In August 2018, Vistra Operations issued $1.0 billion principal amount of 5.50% senior notes due 2026 in an offering to eligible purchasers. The senior notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and Citigroup Global Markets Inc., as representative of the several initial purchasers. Fees and expenses related to the offering totaled $12 million in the three months ended September 30, 2018, which was capitalized as a reduction in the carrying amount of the debt. Net proceeds from the sale of the senior notes totaling approximately $990 million, together with cash on hand and cash received from the funding of the Receivables Facility (see Note 13), were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with the August 2018 cash tender offers described below. The 5.500% senior notes mature in September 2026, with interest payable in cash semiannually in arrears on March 1 and September 1 beginning March 1, 2019.

The indenture governing the 5.500% senior notes provides for the full and unconditional guarantee by certain direct and indirect subsidiaries of Vistra Operations of the punctual payment of the principal and interest on the notes. The Indenture contains certain covenants and restrictions, including, among others, restrictions on the ability of the Issuer and its subsidiaries, as applicable, to create certain liens, merge or consolidate with another entity, and sell all or substantially all of their assets.

Vistra Energy Senior Notes

Bond Repurchase Program — In November 2018, our board of directors (the Board) authorized a bond repurchase program under which up to $200 million principal amount of outstanding Vistra Energy senior notes could be repurchased. Through December 31, 2018, $119 million principal amount of senior notes had been repurchased. Fees and expenses related to the repurchases totaled $7 million in the three months ended December 31, 2018 and were recorded as interest expense and other charges on the statements of consolidated income (loss).

2019 Tender Offer and Consent Solicitation — In February 2019, Vistra Energy used the net proceeds from the issuance of the Vistra Operations 5.625% senior notes due 2027 to fund a cash tender offer (the 2019 Tender Offer) to purchase for cash $1.193 billion aggregate principal amount of 7.375% senior notes due 2022 assumed in the Merger.

In connection with the 2019 Tender Offer, Vistra Energy also commenced solicitation of consents from holders of the 7.375% senior notes due 2022. Vistra Energy received the requisite consents from the holders of the 7.375% senior notes due 2022 and amended the indenture governing these senior notes to, among other things, eliminate substantially all of the restrictive covenants and certain events of default.

August 2018 Tender Offers and Consent Solicitations — In August 2018, Vistra Energy used the net proceeds from the issuance of the Vistra Operations 5.500% senior notes due 2026, proceeds from the Receivables Facility (see Note 13) and cash on hand to fund cash tender offers (the 2018 Tender Offers) to purchase for cash $1.542 billion of senior notes assumed in the Merger. We recorded an extinguishment loss of $27 million on the transactions in the year ended December 31, 2018. Notes purchased consisted of the following:

- $26 million of 7.625% senior notes due 2024;
- $163 million of 8.034% senior notes due 2024;
- $669 million of 8.000% senior notes due 2025, and
- $684 million of 8.125% senior notes due 2026.

In connection with the 2018 Tender Offers, Vistra Energy also commenced solicitations of consents from holders of the 7.375% senior notes due 2022, the 7.625% senior notes due 2024, the 8.034% senior notes due 2024, the 8.000% senior notes due 2025 and the 8.125% senior notes due 2026 to amend certain provisions of the applicable indentures governing each series of senior notes and the registration rights agreement with respect to the 8.125% senior notes due 2026. Vistra Energy received the requisite consents from the holders of the 8.034% senior notes due 2024, the 8.000% senior notes due 2025 and the 8.125% senior notes due 2026 (collectively, the Consent Senior Notes) and amended (a) the indentures governing each series of the applicable senior notes to, among other things, eliminate substantially all of the restrictive covenants and certain events of default and (b) the registration rights agreement with respect to the 8.125% senior notes due 2026 to remove, among other things, the requirement that Vistra Energy commence an exchange offer to issue registered securities in exchange for the existing, nonregistered notes.

Assumption of Senior Notes in Merger — On the Merger Date, Vistra Energy assumed $6.138 billion principal amount of Dynegy's senior notes. In May 2018, $850 million of outstanding 6.75% senior notes due 2019 were redeemed at a redemption price of 101.688% of the aggregate principal amount, plus accrued and unpaid interest to but not including the date of redemption. Fees and expenses related to the redemption totaled $14 million in the three months ended June 30, 2018 and were recorded as interest expense and other charges on the statements of consolidated income (loss). In June 2018, each of the Company's subsidiaries that guaranteed the Vistra Operations Credit Facilities (and did not already guarantee the senior notes) provided a guarantee on the senior notes that remained outstanding.

The senior notes that remain outstanding after the closing of the Tender Offers are unsecured and unsubordinated obligations of Vistra Energy and are guaranteed by substantially all of its current and future wholly owned domestic subsidiaries that from time to time are a borrower or guarantor under the agreement governing the Vistra Operations Credit Facilities (Credit Facilities Agreement) (see Note 24). The respective indentures of the senior notes (except with respect to the Consent Senior Notes) limit, among other things, the ability of the Company or any of the guarantors to create liens upon any principal property to secure debt for borrowed money in excess of, among other limitations, 30% of total assets. The respective indentures of the senior notes also contain customary events of default which would permit the holders of the applicable series of senior notes to declare such notes to be immediately due and payable if not cured within applicable grace periods, including the failure to make timely principal or interest payments on such notes or (except with respect to the Consent Senior Notes) other indebtedness aggregating $100 million or more, and, except with respect to the Consent Senior Notes, the failure to satisfy covenants, and specified events of bankruptcy and insolvency.

Amortizing Notes

On the Merger Date, Vistra Energy assumed the obligations of Dynegy's senior amortizing note (Amortizing Notes) maturing on July 1, 2019. The Amortizing Notes were issued in connection with the issuance of the tangible equity units (TEUs) by Dynegy (see Note 16). Each installment payment per Amortizing Note will be paid in cash and will constitute a partial repayment of principal and a payment of interest, computed at an annual rate of 7.00%. Interest will be calculated on the basis of a 360-day year consisting of twelve 30-day months. Payments will be applied first to the interest due and payable and then to the reduction of the unpaid principal amount, allocated as set forth in the indenture.

The indenture for the Amortizing Notes limits, among other things, the ability of the Company to consolidate, merge, sell, or dispose all or substantially all of its assets. If a fundamental change occurs, or if the Company elects to settle the prepaid stock purchase contracts early, then the holders of the Amortizing Notes will have the right to require the Company to repurchase the Amortizing Notes at a repurchase price equal to the principal amount of the Amortizing Notes as of the repurchase date (as described in the supplemental indenture) plus accrued and unpaid interest. The indenture also contains customary events of default which would permit the holders of the Amortizing Notes to declare those Amortizing Notes to be immediately due and payable if not cured within applicable grace periods, including the failure to make timely installment payments on the Amortizing Notes or other material indebtedness aggregating $100 million or more, the failure to satisfy covenants, and specified events of bankruptcy and insolvency.

Forward Capacity Agreements

On the Merger Date, the Company assumed the obligation of Dynegy's agreements under which a portion of the PJM capacity that cleared for Planning Years 2018-2019, 2019-2020 and 2020-2021 was sold to a financial institution (Forward Capacity Agreements). The buyer in this transaction will receive capacity payments from PJM during the Planning Years 2018-2019, 2019-2020 and 2020-2021 in the amounts of $5 million, $121 million and $110 million, respectively. We will continue to be subject to the performance obligations as well as any associated performance penalties and bonus payments for those planning years. As a result, this transaction is accounted for as long-term debt of $236 million with an implied interest rate of 4.00%.

Equipment Financing Agreements

On the Merger Date, the Company assumed Dynegy's Equipment Financing Agreements. Under certain of our contractual service agreements in which we receive maintenance and capital improvements for our gas-fueled generation fleet, we have obtained parts and equipment intended to increase the output, efficiency and availability of our generation units. We have financed these parts and equipment under agreements with maturities ranging from 2019 to 2026. The portion of future payments attributable to principal will be classified as cash outflows from financing activities, and the portion of future payments attributable to interest will be classified as cash outflows from operating activities in our statements of consolidated cash flows.

Maturities — Long-term debt maturities at December 31, 2018 are as follows:

	December 31, 2018
2019	$ 191
2020	205
2021	129
2022	1,782
2023	4,150
Thereafter	4,453
Unamortized premiums, discounts and debt issuance costs	155
Total long-term debt, including amounts due currently	$ 11,065

Predecessor

DIP Roll Facilities — In August 2016, the Predecessor entered into the DIP Roll Facilities. The facilities provided for up to $4.250 billion in senior secured, super-priority financing. The DIP Roll Facilities were senior, secured, super-priority debtor-in-possession credit agreements by and among the TCEH Debtors, the lenders that were party thereto from time to time and an administrative and collateral agent. On the Effective Date, the DIP Roll Facilities converted to the Vistra Operations Credit Facilities discussed above. Net proceeds from the DIP Roll Facilities totaled $3.465 billion and were used to repay $2.65 billion outstanding borrowings under the former DIP Facility, fund a $650 million collateral account used to backstop issuances of letters of credit and pay $107 million of issuance costs. The remaining balance was used for general corporate purposes. Additionally, $800 million of cash from collateral accounts under the former DIP Facility that was used to backstop letters of credit was released to the Predecessor to be used for general corporate purposes.

DIP Facility — The DIP Facility provided for up to $3.375 billion in senior secured, super-priority financing. The DIP Facility was a senior, secured, super-priority credit agreement by and among the TCEH Debtors, the lenders that were party thereto from time to time and an administrative and collateral agent. As discussed above, in August 2016, all outstanding amounts under the DIP Facility were repaid using proceeds from the DIP Roll Facilities.

15. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

At December 31, 2018, we had contractual commitments under long-term service and maintenance contracts, energy-related contracts, leases and other agreements as follows.

	Long-Term Service and Maintenance Contracts	Coal purchase and transportation agreements	Pipeline transportation and storage reservation fees	Nuclear Fuel Contracts	Other Contracts
2019	$ 175	$ 765	$ 101	$ 69	$ 101
2020	181	227	95	71	74
2021	135	118	72	58	20
2022	183	103	48	38	13
2023	133	64	35	46	9
Thereafter	2,619	186	145	155	68
Total	$ 3,426	$ 1,463	$ 496	$ 437	$ 285

The table above excludes TRA and pension and OPEB plan obligations due to the uncertainty in the timing of those payments.

Expenditures under our coal purchase and coal transportation agreements totaled $955 million, $416 million, $109 million and $139 million for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively.

At December 31, 2018, future minimum lease payments under operating leases are as follows:

	Operating Leases (a)
2019	$ 35
2020	29
2021	25
2022	20
2023	19
Thereafter	168
Total future minimum lease payments	$ 296

(a) Includes operating leases with initial or remaining noncancellable lease terms in excess of one year.

Rent reported as operating costs, fuel costs and SG&A expenses totaled $74 million, $69 million, $20 million and $39 million for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively.

Guarantees

We have entered into contracts, including the assumed Dynegy senior notes described above, that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. As of December 31, 2018, there are no material outstanding claims related to our guarantee obligations, and we do not anticipate we will be required to make any material payments under these guarantees.

Letters of Credit

At December 31, 2018, we had outstanding letters of credit under the Vistra Operations Credit Facilities totaling $1.365 billion as follows:

- $1.185 billion to support commodity risk management collateral requirements in the normal course of business, including over-the-counter and exchange-traded transactions and collateral postings with ISOs or RTOs;
- $53 million to support executory contracts and insurance agreements;
- $55 million to support our REP financial requirements with the PUCT, and
- $72 million for other credit support requirements.

Surety Bonds

At December 31, 2018, we had outstanding surety bonds totaling $31 million to support performance under various contracts and legal obligations in the normal course of business.

Litigation

Gas Index Pricing Litigation — We, through our subsidiaries, and other energy companies are named as defendants in several lawsuits claiming damages resulting from alleged price manipulation through false reporting of natural gas prices to various index publications, wash trading and churn trading from 2000-2002. The cases allege that the defendants engaged in an antitrust conspiracy to inflate natural gas prices in three states (Kansas, Missouri and Wisconsin) during the relevant time period and seek damages under the respective state antitrust statutes. Four of the cases are putative class actions and one case, *Reorganized FLI (nka J.P. Morgan Trust Co., National Assn.) v. Oneok Inc., et al*., is an individual action on behalf of Farmland Industries, Inc. (Farmland), with Farmland seeking full consideration damages (*i.e*., the full amount it paid for natural gas purchases during the relevant timeframe). The cases are consolidated in a multi-district litigation proceeding pending in the U. S. District Court for Nevada. In March 2017, the court denied the class plaintiffs' motions to certify class actions in each of the states, which decision was taken on an interlocutory appeal to U.S Court of Appeals for the Ninth Circuit (Ninth Circuit Court). In August 2018, the Ninth Circuit Court vacated the district court orders denying class certification and remanded the cases to the district court for further consideration of the class certification issue. In September 2018, the defendants filed a joint motion for entry of an order denying class certification, and the plaintiffs filed a motion for remand of the cases to the transferor courts to decide class certification issues. In January 2019, the judge issued an order remanding the consolidated cases in the multi-district proceedings back to their respective courts of origin. Along with the other defendants, we had previously reached settlement terms in the Kansas and Missouri cases, and plaintiffs in those cases filed a Notice of Settlement with the judge in the multi-district court proceeding. As for the Farmland matter, in March 2018, the Ninth Circuit Court reversed a summary judgment in favor of the defendants and it shortly will be remanded for further discovery and other pretrial proceedings. While we cannot predict the outcome of these legal proceedings, or estimate a range of costs, they could have a material impact on our results of operations, liquidity or financial condition.

Advatech Dispute — In September 2016, Illinois Power Generating Company (Genco), terminated its Second Amended and Restated Newton Flue Gas Desulfurization System Engineering, Procurement, Construction and Commissioning Services Contract dated as of December 15, 2014 with Advatech, LLC (Advatech). Advatech issued Genco its final invoice in September 2016 totaling $81 million. Genco contested the invoice in October 2016 and believes the proper amount is less than $1 million. In October 2016, Advatech initiated the dispute resolution process under the contract and filed for arbitration in March 2017. Settlement discussions required under the dispute resolution process were unsuccessful. The arbitration hearing occurred in October 2018, and the arbitration panel has not yet issued an award. We dispute the allegations. While we cannot predict the outcome of this legal proceeding, or estimate a range of costs, it could have a material impact on our results of operations, liquidity or financial condition.

Wood River Rail Dispute — In November 2017, Dynegy Midwest Generation, LLC (DMG) received notification that BNSF Railway Company and Norfolk Southern Railway Company were initiating dispute resolution related to DMG's suspension of its Wood River Rail Transportation Agreement with the railroads. Settlement discussions required under the dispute resolution process have been unsuccessful. In March 2018, BNSF Railway Company and Norfolk Southern Railway Company filed a demand for arbitration. The arbitration hearing on the merits is schedule for February 2020. We dispute the railroads' allegations and will defend our position vigorously. While we cannot predict the outcome of this legal proceeding, or estimate a range of costs, it could have a material impact on our results of operations, liquidity or financial condition.

Greenhouse Gas Emissions

In August 2015, the EPA finalized rules to address greenhouse gas (GHG) emissions from new, modified and reconstructed and existing electricity generation units, referred to as the Clean Power Plan, including rules for existing facilities that would establish state-specific emissions rate goals to reduce nationwide CO_2 emissions. Various parties (including Luminant) filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) and subsequently, in January 2016, a coalition of states, industry (including Luminant) and other parties filed applications with the U.S. Supreme Court (Supreme Court) asking that the Supreme Court stay the rule while the D.C. Circuit Court reviews the legality of the rule for existing plants. In February 2016, the Supreme Court stayed the rule pending the conclusion of legal challenges on the rule before the D.C. Circuit Court and until the Supreme Court disposes of any subsequent petition for review. Oral argument on the merits of the legal challenges to the rule was heard in September 2016 before the entire D.C. Circuit Court, but the D.C. Circuit Court has not issued a decision and the case remains in abeyance due to the EPA's decision to review the Clean Power Plan.

In October 2017, the EPA issued a proposed rule that would repeal the Clean Power Plan, with the proposed repeal focusing on what the EPA believes to be the unlawful nature of the Clean Power Plan and asking for public comment on the EPA's interpretations of its authority under the Clean Air Act. In December 2017, the EPA published an advance notice of proposed rulemaking (ANPR) soliciting information from the public as the EPA considers proposing a future rule. Vistra Energy submitted comments on the ANPR in February 2018. Vistra Energy submitted comments on the proposed repeal in April 2018. In August 2018, the EPA published a proposed replacement rule called the Affordable Clean Energy rule. We submitted comments on the proposed Affordable Clean Energy rule in October 2018. In December 2018, the EPA issued proposed revisions to the emission standards for new, modified and reconstructed units with comments due in March 2019. While we cannot predict the outcome of these rulemakings and related legal proceedings, or estimate a range of reasonably probable costs, if the rules are ultimately implemented or upheld as they were issued, they could have a material impact on our results of operations, liquidity or financial condition.

Regional Haze — Reasonable Progress and Best Available Retrofit Technology (BART) for Texas

In January 2016, the EPA issued a final rule approving in part and disapproving in part Texas's 2009 State Implementation Plan (SIP) as it relates to the reasonable progress component of the Regional Haze Program and issuing a Federal Implementation Plan (FIP). The EPA's emission limits in the FIP assume additional control equipment for specific lignite/coal-fueled generation units across Texas, including new flue gas desulfurization systems (scrubbers) at seven electricity generation units (including Big Brown Units 1 and 2, Monticello Units 1 and 2 and Coleto Creek) and upgrades to existing scrubbers at seven generation units (including Martin Lake Units 1, 2 and 3, Monticello Unit 3 and Sandow Unit 4).

In March 2016, Luminant and a number of other parties, including the State of Texas, filed petitions for review in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court) challenging the FIP's Texas requirements. In July 2016, the Fifth Circuit Court granted motions to stay the rule filed by Luminant and the other parties pending final review of the petitions for review. In December 2016, the EPA filed a motion seeking a voluntary remand of the rule back to the EPA for further consideration of Luminant's pending request for administrative reconsideration. In March 2017, the Fifth Circuit Court remanded the rule back to the EPA for reconsideration. The stay of the rule (and the emission control requirements) remains in effect, and the EPA is required to file status reports of its reconsideration every 60 days. The retirements of our Monticello, Big Brown and Sandow 4 plants should have a favorable impact on this rulemaking and litigation. While we cannot predict the outcome of the rulemaking and legal proceedings, or estimate a range of reasonably possible costs, the result could have a material impact on our results of operations, liquidity or financial condition.

In September 2017, the EPA signed a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas's 2009 SIP and a partial FIP. For SO_2, the rule creates an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generating units (including our Martin Lake, Big Brown, Monticello, Sandow 4, Coleto Creek, Stryker 2 and Graham 2 plants). The compliance obligations in the program started on January 1, 2019, and the identified units receive an annual allowance allocation that is equal to their most recent annual CSAPR SO_2 allocation. Cumulatively, our units covered by the program are allocated 100,279 allowances annually. Under the rule, a unit that is listed that does not operate for two consecutive years starting after 2018 would no longer receive allowances after the fifth year of non-operation. We believe the retirements of our Monticello, Big Brown and Sandow 4 plants will enhance our ability to comply with this BART rule for SO_2. For NO_X, the rule adopts the CSAPR's ozone program as BART and for particulate matter, the rule approves Texas's SIP that determines that no electricity generation units are subject to BART for particulate matter. The National Parks Conservation Association, the Sierra Club and the Environmental Defense Fund filed a petition challenging the rule in the Fifth Circuit Court as well as a petition for reconsideration filed with the EPA. Luminant intervened on behalf of the EPA in the Fifth Circuit Court action. In March 2018, the Fifth Circuit Court granted a joint motion filed by the EPA and the environmental groups involved to abate the Fifth Circuit Court proceedings until the EPA has taken action on the reconsideration petition and concludes the reconsideration process. In August 2018, the EPA issued a proposed rule affirming the prior BART final rule and seeking comments on that proposal, which were due in October 2018. While we cannot predict the outcome of the rulemaking and legal proceedings, we believe the rule, if ultimately implemented or upheld as issued, will not have a material impact on our results of operations, liquidity or financial condition.

Affirmative Defenses During Malfunctions

In February 2013, the EPA proposed a rule requiring certain states to remove SIP exemptions for excess emissions during malfunctions or replace them with an affirmative defense. In May 2015, the EPA finalized its 2013 proposal to extend the EPA's proposed findings of inadequacy to states that have affirmative defense provisions, including Texas. The final rule impacted 36 states, including Texas, Illinois and Ohio, in which we operate. The EPA's final rule would require covered states to remove or replace either EPA-approved exemptions or affirmative defense provisions for excess emissions during startup, shutdown and maintenance events. Several states (including the State of Texas and the State of Ohio) and various industry parties (including Luminant) filed petitions for review of the EPA's final rule, and all of those petitions were consolidated in the D.C. Circuit Court. Before the oral argument was held, in April 2017, the D.C. Circuit Court granted the EPA's motion to continue oral argument and ordered that the case be held in abeyance with the EPA to provide status reports to the D.C. Circuit Court on the EPA's review of the action at 90-day intervals. In October 2018, the EPA partially granted Texas' petition for reconsideration of the Texas SIP call. We cannot predict the timing or outcome of this proceeding, or estimate a range of reasonably possible costs, but implementation of the rule as finalized could have a material impact on our results of operations, liquidity or financial condition.

SO_2 Designations for Texas

In November 2016, the EPA finalized its nonattainment designations for counties surrounding our Big Brown, Monticello and Martin Lake generation plants. The final designations require Texas to develop nonattainment plans for these areas. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court. Subsequently, in October 2017, the Fifth Circuit Court granted the EPA's motion to hold the case in abeyance considering the EPA's representation that it intended to revisit the nonattainment rule. In December 2017, the TCEQ submitted a petition for reconsideration to the EPA. In addition, with respect to Monticello and Big Brown, the retirement of those plants should favorably impact our legal challenge to the nonattainment designations in that the nonattainment designations for Freestone County and Titus County are based solely on the Sierra Club modeling, which we dispute, of SO_2 emissions from Monticello and Big Brown. Regardless, considering these retirements, the nonattainment designations for those counties are no longer supported. While we cannot predict the outcome of this matter, or estimate a range of reasonably possible costs, the result could have a material impact on our results of operations, liquidity or financial condition.

Effluent Limitation Guidelines (ELGs)

In November 2015, the EPA revised the ELGs for steam electricity generation facilities, which will impose more stringent standards (as individual permits are renewed) for wastewater streams, flue desulfurization, fly ash, bottom ash and flue gas mercury control. Various parties filed petitions for review of the ELG rule, and the petitions were consolidated in the Fifth Circuit Court. In April 2017, the EPA granted petitions requesting reconsideration of the ELG final rule issued in 2015 and administratively stayed the ELG rule's compliance date deadlines pending ongoing judicial review of the rule. The legal challenges pertaining to bottom ash transport water, flue gas desulfurization wastewater and gasification wastewater have been suspended while the EPA reconsiders the rules.

The EPA issued a final rule in September 2017 postponing the earliest compliance dates in the ELG rule for bottom ash transport water and flue-gas desulfurization wastewater by two years, from November 1, 2018 to November 1, 2020.

Given the EPA's decision to reconsider the bottom ash transport water and flue gas desulfurization wastewater provisions of the ELG rule, the rule postponing the ELG rule's earliest compliance dates for those provisions, and the intertwined relationship of the ELG rule with the Coal Combustion Residuals rule discussed below, which is also being reconsidered by the EPA, as well as pending legal challenges concerning both rules, substantial uncertainty exists regarding our projected capital expenditures for ELG compliance, including the timing of such expenditures. While we cannot predict the outcome of this matter, or estimate a range of costs, it could have a material impact on our results of operations, liquidity or financial condition.

New Source Review and CAA Matters

New Source Review — Since 1999, the EPA has engaged in a nationwide enforcement initiative to determine whether coal-fueled power plants failed to comply with the requirements of the New Source Review (NSR) and New Source Performance Standard provisions under the CAA when the plants implemented changes. The EPA's NSR initiative focuses on whether projects performed at power plants triggered various permitting requirements, including the need to install pollution control equipment.

In August 2013, the U.S. Department of Justice (DOJ), acting as the attorneys for the EPA, filed a civil enforcement lawsuit against Luminant in federal district court in Dallas, alleging violations of the CAA, including its NSR standards, at our Big Brown and Martin Lake generation facilities. The lawsuit requests (i) the maximum civil penalties available under the CAA to the government of up to $32,500 to $37,500 per day for each alleged violation, depending on the date of the alleged violation, and (ii) injunctive relief, including an order to apply for pre-construction permits which may require the installation of best available control technology at the affected units. In August 2015, the district court granted Luminant's motion to dismiss seven of the nine claims asserted by the EPA in the lawsuit.

In January 2017, the EPA dismissed its two remaining claims with prejudice and the district court entered final judgment in Luminant's favor. In March 2017, the EPA and the Sierra Club appealed the final judgment to the Fifth Circuit Court. After the parties filed their respective briefs in the Fifth Circuit Court, the appeal was argued before the Fifth Circuit Court in March 2018. In October 2018, the Fifth Circuit Court affirmed in part, reversed in part, and remanded to the district court. The Fifth Circuit Court's decision held that the district court properly dismissed all of the civil penalties as time-barred. The Fifth Circuit Court further held that the grounds cited by the district court did not support dismissal of the injunctive relief claims at this early stage of the case and remanded the case back to the district court for further consideration. In November 2018, we filed a petition for rehearing en banc on two issues and the EPA's response to that petition is due in February 2019. We believe that we have complied with all requirements of the CAA and intend to continue to vigorously defend against the remaining allegations. An adverse outcome could require substantial capital expenditures that cannot be determined at this time or retirement of the remaining plant at issue, Martin Lake. The retirement of the Big Brown plant should have a favorable impact on this litigation. We cannot predict the outcome of these proceedings, including the financial effects, if any.

Zimmer NOVs — In December 2014, the EPA issued a notice of violation (NOV) alleging violation of opacity standards at the Zimmer facility. The EPA previously had issued NOVs to Zimmer in 2008 and 2010 alleging violations of the CAA, the Ohio State Implementation Plan and the station's air permits including standards applicable to opacity, sulfur dioxide, sulfuric acid mist and heat input. The NOVs remain unresolved. We are unable to predict the outcome of these matters.

Edwards CAA Citizen Suit — In April 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our MISO segment's Edwards facility. In August 2016, the district court granted the plaintiffs' motion for summary judgment on certain liability issues. We filed a motion seeking interlocutory appeal of the court's summary judgment ruling. In February 2017, the appellate court denied our motion for interlocutory appeal. The parties completed briefing on motions for summary judgment on remedy issues in October 2018. In January 2019, the court canceled the bench trial scheduled for March 2019 and denied the parties' motions for summary judgment on remedy issues. In February 2019, the court issued an order that anticipates a trial date at the end of September 2019. We dispute the allegations and will defend the case vigorously. We are unable to predict the outcome of these matters.

Ultimate resolution of any of these CAA matters could have a material adverse impact on our future financial condition, results of operations, and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties, or could result in an order or a decision to retire these plants. While we cannot predict the outcome of these legal proceedings, or estimate a range of costs, they could have a material impact on our results of operations, liquidity or financial condition.

Coal Combustion Residuals/Groundwater

In July 2018, the EPA published a final rule that amends certain provisions of the Coal Combustion Residuals (CCR) rule that the agency issued in 2015. The 2018 revisions extend closure deadlines to October 31, 2020, related to the aquifer location restriction and groundwater monitoring requirements. The 2018 revisions also (1) establish groundwater protection standards for cobalt, lithium, molybdenum and lead (2) allow authorized state programs to waive groundwater monitoring requirements when there is a demonstration of no potential for contaminant migration, and (3) allow the permitting authority to issue certifications in lieu of a qualified professional engineer. The 2018 revisions became effective in August 2018, and we are continuing to evaluate the impact on our CCR facilities. Also, on August 21, 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule. The EPA is expected to undertake further revisions to its CCR regulations in response to the D.C. Circuit Court's ruling. In October 2018, the rule that extends certain closure deadlines to 2020 was challenged in the D.C. Circuit Court. In December 2018, the EPA and petitioners filed cross-motions, with the EPA seeking remand without vacatur and petitioners seeking a partial stay or vacatur of the rule. We have intervened in the litigation and filed a motion in support of the EPA. Briefing on the cross-motions is ongoing. While we cannot predict the impacts of these rule revisions (including whether and if so how the states in which we operate will utilize the authority delegated to the states through the revisions), or estimate a range of reasonably possible costs related to these revisions, the changes that result from these revisions could have a material impact on our results of operations, liquidity or financial condition.

MISO Segment — In 2012, the Illinois Environmental Protection Agency (IEPA) issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities' CCR surface impoundments. In 2016, the IEPA approved our closure and post-closure care plans for the Baldwin old east, east, and west fly ash CCR surface impoundments. We are working towards implementation of those closure plans.

At our retired Vermilion facility, which was not subject to the EPA's 2015 CCR rule until the August 2018 court decision, we submitted proposed corrective action plans involving closure of two CCR surface impoundments (*i.e.*, the old east and the north impoundments) to the IEPA in 2012, with revised plans submitted in 2014. In May 2017, in response to a request from the IEPA for additional information regarding the closure of these Vermilion surface impoundments, we agreed to perform additional groundwater sampling and closure options and riverbank stabilizing options. By letter dated January 31, 2018, Prairie Rivers Network provided 60-day notice of its intent to sue our subsidiary Dynegy Midwest Generation, LLC under the federal Clean Water Act for alleged unauthorized discharges from the surface impoundments at our Vermilion facility and alleged related violations of the facility's National Pollutant Discharge Elimination System permit. Prairie Rivers Network filed a citizen suit in May 2018, alleging violations of the Clean Water Act for alleged unauthorized discharges. In August 2018, we filed a motion to dismiss the lawsuit. In November 2018, the district court granted our motion to dismiss and judgment was entered in our favor. Plaintiffs have appealed the judgment to the U.S Court of Appeals for the Ninth Circuit. We dispute the allegations and will vigorously defend our position.

In 2012, the IEPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. We are addressing these CCR surface impoundments in accordance with the federal CCR rule. In June 2018, the IEPA issued a violation notice for alleged seep discharges claimed to be coming from the surface impoundments at our retired Vermilion facility.

In December 2018, the Sierra Club filed a complaint with the IPCB alleging the disposal and storage of coal ash at the Coffeen, Edwards and Joppa generation facilities are causing exceedances of the applicable groundwater standards. We dispute the allegations and will vigorously defend our position.

If remediation measures concerning groundwater are necessary at any of our coal-fueled facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations, and cash flows. At this time, in part because of the revisions to the CCR rule that the EPA published in July 2018 and the D.C. Circuit Court's vacatur and remand of certain provisions of the EPA's 2015 CCR rule, we cannot reasonably estimate the costs, or range of costs, of groundwater remediation, if any, that ultimately may be required. CCR surface impoundment and landfill closure costs, as determined by our operations and environmental services teams, are reflected in our AROs.

MISO 2015-2016 Planning Resource Auction

In May 2015, three complaints were filed at FERC regarding the Zone 4 results for the 2015-2016 Planning Resource Auction (PRA) conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General and Southwestern Electric Cooperative, Inc., have challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds, and requested changes to the MISO PRA structure going forward. Complainants have also alleged that Dynegy could have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the 2015-2016 PRA. The Independent Market Monitor for MISO (MISO IMM), which was responsible for monitoring the MISO 2015-2016 PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the proposed remedies. We filed our Answer to these complaints and believe that we complied fully with the terms of the MISO tariff in connection with the 2015-2016 PRA, disputed the allegations, and will defend our actions vigorously. In addition, the Illinois Industrial Energy Consumers filed a complaint at FERC against MISO on June 30, 2015 requesting prospective changes to the MISO tariff. Dynegy also responded to this complaint.

On October 1, 2015, FERC issued an order of non-public, formal investigation, stating that shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public informal investigation into whether market manipulation or other potential violations of FERC orders, rules, and regulations occurred before or during the PRA (the Order). The Order noted that the investigation is ongoing, and that the conversion of the informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. Vistra Energy is participating in the investigation on behalf of Dynegy following the closing of the Merger. We believe that our conduct was proper and will defend our position vigorously, but we cannot predict the outcome of the investigation or the amount, if any, of loss that may result. While we cannot predict the outcome of this matter, or estimate a range of costs, it could have a material impact on our results of operations, liquidity or financial condition.

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. The order did not address the arguments of the complainants regarding the 2015-2016 PRA and stated that those issues remain under consideration and will be addressed in a future order.

Other Matters

We are involved in various legal and administrative proceedings in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

Labor Contracts

We employ certain personnel who are represented by labor unions, the terms of whose employment are governed by collective bargaining agreements. The terms of all collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal- and nuclear-fueled generation operations and some of our natural gas-fueled generation operations expire on various dates between March 2019 and March 2022, but remain effective from year-to-year thereafter unless and until terminated by either party. While we cannot predict the outcome of labor contract negotiations, we do not expect any changes in collective bargaining agreements to have a material adverse effect on our results of operations, liquidity or financial condition.

Nuclear Insurance

Nuclear insurance includes nuclear liability coverage, property damage, decontamination and accidental premature decommissioning coverage and accidental outage and/or extra expense coverage. We maintain nuclear insurance that meets or exceeds requirements promulgated by Section 170 (Price-Anderson) of the Atomic Energy Act (the Act) and Title 10 of the Code of Federal Regulations. We intend to maintain insurance against nuclear risks as long as such insurance is available. We are self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Any such self-insured losses could have a material adverse effect on our results of operations, liquidity or financial condition.

With regard to liability coverage, the Act provides for financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $14.1 billion and requires nuclear generation plant operators to provide financial protection for this amount. However, the United States Congress could impose revenue-raising measures on the nuclear industry to pay claims that exceed the $14.1 billion limit for a single incident. As required, we insure against a possible nuclear incident at our Comanche Peak facility resulting in public nuclear-related bodily injury and property damage through a combination of private insurance and an industry-wide retrospective payment plan known as Secondary Financial Protection (SFP).

Under the SFP, in the event of any single nuclear liability loss in excess of $450 million at any nuclear generation facility in the United States, each operating licensed reactor in the United States is subject to an annual assessment of up to $137.6 million. This approximately $137.6 million maximum assessment is subject to increases for inflation every five years, with the next expected adjustment scheduled to occur in September 2023. Assessments are currently limited to $20.5 million per operating licensed reactor per year per incident. As of December 31, 2018, our maximum potential assessment under the industry retrospective plan would be approximately $275 million per incident but no more than $41 million in any one year for each incident. The potential assessment is triggered by a nuclear liability loss in excess of $450 million per accident at any nuclear facility.

The United States Nuclear Regulatory Commission (NRC) requires that nuclear generation plant license holders maintain at least $1.06 billion of nuclear decontamination and property damage insurance, and requires that the proceeds thereof be used to place a plant in a safe and stable condition, to decontaminate a plant pursuant to a plan submitted to, and approved by, the NRC prior to using the proceeds for plant repair or restoration, or to provide for premature decommissioning. We maintain nuclear decontamination and property damage insurance for our Comanche Peak facility in the amount of $2.25 billion and non-nuclear related property damage in the amount of $1.5 billion (subject to a $5 million deductible per accident except for natural hazards which are subject to a $9.5 million deductible per accident), above which we are self-insured.

We also maintain Accidental Outage insurance to cover the additional costs of obtaining replacement electricity from another source if one or both of the units at our Comanche Peak facility are out of service for more than twelve weeks as a result of covered direct physical damage. Such coverage provides for weekly payments per unit up to $4.5 million for the first 52 weeks and up to $3.6 million for the remaining 71 weeks. The total maximum coverage is $328 million for non-nuclear property damage and $490 million for nuclear property damage. The coverage amounts applicable to each unit will be reduced to 80% if both units are out of service at the same time as a result of the same accident.

16. EQUITY

Successor Shareholders' Equity

Equity Issuances and Repurchases — Changes in the number of shares of common stock outstanding for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 are reflected in the table below.

	Successor		
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016
Shares outstanding at beginning of period	428,398,802	427,580,232	—
Shares issued (a)	97,639,105	818,570	427,580,232
Shares retired	(6,815)	—	—
Shares repurchased (b)	(32,815,783)	—	—
Shares outstanding at end of period	493,215,309	428,398,802	427,580,232

(a) Includes share awards granted to nonemployee directors. The year ended December 31, 2018 includes 94,409,573 shares issued in connection with the Merger (see Note 2).
(b) Treasury shares totaled 32,815,783 shares at December 31, 2018, all of which were acquired during the year ended December 31, 2018 in connection with the share repurchase program described below.

Share Repurchase Program — In June 2018, we announced that the Board had authorized a share repurchase program under which up to $500 million of our outstanding common stock could be repurchased. Repurchases under this program were completed on October 19, 2018. On a cumulative basis, 21,421,925 shares of our common stock were repurchased for $500 million (including related fees and expenses) at an average price per share of common stock of $23.36.

In November 2018, we announced that the Board had authorized an incremental share repurchase program (Program) under which up to $1.250 billion of our outstanding stock may be purchased. Through December 31, 2018, 12,073,091 shares of our common stock had been repurchased for $278 million (including related fees and expenses) at an average price per share of common stock of $22.99. At December 31, 2018, $972 million was available for additional repurchases under the Program, and we intend to implement the Program opportunistically from time to time through the end of 2019.

Shares of the Company's common stock may be repurchased in open market transactions at prevailing market prices, in privately negotiated transactions, pursuant to plans complying with the Securities Exchange Act of 1934, as amended, or by other means in accordance with federal securities laws. The actual timing, number and value of shares repurchased under the Program will be determined at our discretion and will depend on a number of factors, including the market price of our stock, general market and economic conditions, applicable legal requirements and compliance with the terms of our debt agreements and the Tax Matters Agreement.

Dividends — Vistra Energy did not declare or pay any dividends during the years ended December 31, 2018 and 2017. In December 2016, the Board approved the payment of a special cash dividend (Special Dividend) in the aggregate amount of approximately $1 billion ($2.32 per share of common stock) to holders of record of our common stock on December 19, 2016. The dividend was funded using borrowings under the Vistra Operations Credit Facilities.

Dividend Restrictions — The agreement governing the Credit Facilities Agreement generally restricts the ability of Vistra Operations to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2018, Vistra Operations can distribute approximately $9.3 billion to Vistra Energy Corp. (the Parent) under the Credit Facilities Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to the Parent was partially reduced by distributions made by Vistra Operations to Parent during the years ended December 31, 2018 and 2017 of approximately $4.7 billion and $1.1 billion, respectively. In February 2019, Vistra Operations made an additional distribution to the Parent of approximately $1.45 billion. Additionally, Vistra Operations may make distributions to the Parent in amounts sufficient for the Parent to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of the Parent's ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2018, the maximum amount of restricted net assets of Vistra Operations that may not be distributed to Parent totaled approximately $6.5 billion.

Under applicable Delaware General Corporate Law, we are prohibited from paying any distribution to the extent that such distribution exceeds the value of our "surplus," which is defined as the excess of our net assets above our capital (the aggregate par value of all outstanding shares of our stock).

Accumulated Other Comprehensive Income — During the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016, we recorded changes in the funded status of our pension and other postretirement employee benefit liability totaling $9 million, $(23) million and $6 million, respectively. During the year ended December 31, 2018, $(3) million was reclassified from accumulated other comprehensive income and reported in other deductions. During the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, no amounts were reclassified from accumulated other comprehensive income.

Warrants — At the Merger Date, the Company entered into an agreement whereby holders of each outstanding warrant previously issued by Dynegy will be entitled to receive, upon exercise, the equity securities to which the holder would have been entitled to receive of Dynegy common stock converted into shares of Vistra Energy common stock at the Exchange Ratio. As of December 31, 2018, nine million warrants expiring in 2024 with an exercise price of $35.00 were outstanding, each of which can be redeemed for 0.652 share of Vistra Energy common stock. The warrants are recorded as equity in our consolidated balance sheet.

Tangible Equity Units — At the Merger Date, the Company assumed the obligations of Dynegy's 4,600,000 7.00% tangible equity units, each with a stated amount of $100.00 and each comprised of (i) a prepaid stock purchase contract that will deliver to the holder, not later than July 1, 2019, unless earlier redeemed or settled, not more than 4.0421 shares of Vistra Energy common stock and not less than 3.2731 shares of Vistra Energy common stock per contract based upon the applicable fixed settlement rate in the contract and (ii) a senior amortizing note with an outstanding principal amount of $38 million at the Merger Date that pays an equal quarterly cash installment of $1.75 per amortizing note (see Note 14). In the aggregate, the annual quarterly cash installments will be equivalent to a 7.00% cash payment per year with respect to each $100.00 stated amount of tangible equity units. The amortizing notes are accounted for as debt while the stock purchase contract is included in equity based on the fair value of the contract at the Merger Date (See Statements of Consolidated Equity and Note 14).

Predecessor Membership Interests

TCEH paid no dividends in the period from January 1, 2016 through October 2, 2016.

17. FAIR VALUE MEASUREMENTS

We utilize several different valuation techniques to measure the fair value of assets and liabilities, relying primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities for those items that are measured on a recurring basis. We use a mid-market valuation convention (the mid-point price between bid and ask prices) as a practical expedient to measure fair value for the majority of our assets and liabilities and use valuation techniques to maximize the use of observable inputs and minimize the use of unobservable inputs. Our valuation policies and procedures were developed, maintained and validated by a centralized risk management group that reports to the Vistra Energy Chief Financial Officer.

Fair value measurements of derivative assets and liabilities incorporate an adjustment for credit-related nonperformance risk. These nonperformance risk adjustments take into consideration master netting arrangements, credit enhancements and the credit risks associated with our credit standing and the credit standing of our counterparties (see Note 18 for additional information regarding credit risk associated with our derivatives). We utilize credit ratings and default rate factors in calculating these fair value measurement adjustments.

We categorize our assets and liabilities recorded at fair value based upon the following fair value hierarchy:

- Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Our Level 1 assets and liabilities include CME or ICE (electronic commodity derivative exchanges) futures and options transacted through clearing brokers for which prices are actively quoted. We report the fair value of CME and ICE transactions without taking into consideration margin deposits, with the exception of certain margin amounts related to changes in fair value on certain CME transactions that, beginning in January 2017, are legally characterized as settlement of derivative contracts rather than collateral.

- Level 2 valuations utilize over-the-counter broker quotes, quoted prices for similar assets or liabilities that are corroborated by correlations or other mathematical means, and other valuation inputs such as interest rates and yield curves observable at commonly quoted intervals. We attempt to obtain multiple quotes from brokers that are active in the markets in which we participate and require at least one quote from two brokers to determine a pricing input as observable. The number of broker quotes received for certain pricing inputs varies depending on the depth of the trading market, each individual broker's publication policy, recent trading volume trends and various other factors.

- Level 3 valuations use unobservable inputs for the asset or liability. Unobservable inputs are used to the extent observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. We use the most meaningful information available from the market combined with internally developed valuation methodologies to develop our best estimate of fair value. Significant unobservable inputs used to develop the valuation models include volatility curves, correlation curves, illiquid pricing delivery periods and locations and credit-related nonperformance risk assumptions. These inputs and valuation models are developed and maintained by employees trained and experienced in market operations and fair value measurements and validated by the Company's risk management group.

With respect to amounts presented in the following fair value hierarchy tables, the fair value measurement of an asset or liability (*e.g.*, a contract) is required to fall in its entirety in one level, based on the lowest level input that is significant to the fair value measurement.

Assets and liabilities measured at fair value on a recurring basis consisted of the following at the respective balance sheet dates shown below:

December 31, 2018	Level 1	Level 2	Level 3 (a)	Reclassification (b)	Total
Assets:					
Commodity contracts	$ 456	$ 152	$ 153	$ 1	$ 762
Interest rate swaps	—	77	—	—	77
Nuclear decommissioning trust – equity securities (c)	449	—	—	—	449
Nuclear decommissioning trust – debt securities (c)	—	443	—	—	443
Sub-total	$ 905	$ 672	$ 153	$ 1	1,731
Assets measured at net asset value (d):					
Nuclear decommissioning trust – equity securities (c)					278
Total assets					$ 2,009
Liabilities:					
Commodity contracts	$ 557	$ 766	$ 288	$ 1	$ 1,612
Interest rate swaps	—	34	—	—	34
Total liabilities	$ 557	$ 800	$ 288	$ 1	$ 1,646

December 31, 2017	Level 1	Level 2	Level 3 (a)	Reclassification (b)	Total
Assets:					
Commodity contracts	$ 47	$ 98	$ 75	$ 2	$ 222
Interest rate swaps	—	18	—	8	26
Nuclear decommissioning trust – equity securities (c)	468	—	—	—	468
Nuclear decommissioning trust – debt securities (c)	—	430	—	—	430
Sub-total	$ 515	$ 546	$ 75	$ 10	1,146
Assets measured at net asset value (d):					
Nuclear decommissioning trust – equity securities (c)					290
Total assets					$ 1,436
Liabilities:					
Commodity contracts	$ 45	$ 143	$ 128	$ 2	$ 318
Interest rate swaps	—	—	—	8	8
Total liabilities	$ 45	$ 143	$ 128	$ 10	$ 326

(a) See table below for description of Level 3 assets and liabilities.
(b) Fair values are determined on a contract basis, but certain contracts result in a current asset and a noncurrent liability, or vice versa, as presented in our consolidated balance sheets.
(c) The nuclear decommissioning trust investment is included in the other investments line in our consolidated balance sheets. See Note 23.
(d) The fair value amounts presented in this line are intended to permit reconciliation of the fair value hierarchy to the amounts presented in our consolidated balance sheets. Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been classified in the fair value hierarchy.

Commodity contracts consist primarily of natural gas, electricity, fuel oil, uranium, coal and emissions agreements and include financial instruments entered into for economic hedging purposes as well as physical contracts that have not been designated as normal purchases or sales. Interest rate swaps are used to reduce exposure to interest rate changes by converting floating-rate interest to fixed rates. See Note 18 for further discussion regarding derivative instruments.

Nuclear decommissioning trust assets represent securities held for the purpose of funding the future retirement and decommissioning of our nuclear generation facility. These investments include equity, debt and other fixed-income securities consistent with investment rules established by the NRC and the PUCT.

The following tables present the fair value of the Level 3 assets and liabilities by major contract type and the significant unobservable inputs used in the valuations at December 31, 2018 and 2017:

December 31, 2018

	Fair Value					
Contract Type (a)	**Assets**	**Liabilities**	**Total**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**
Electricity purchases and sales	$ 22	$ (48)	$ (26)	Valuation Model	Hourly price curve shape (c)	$0 to $110/ MWh
					Illiquid delivery periods for ERCOT hub power prices and heat rates (d)	$20 to $120/ MWh
Electricity and weather options	31	(192)	(161)	Option Pricing Model	Gas to power correlation (e)	15% to 95%
					Power volatility (e)	5% to 435%
Financial transmission rights	85	(20)	65	Market Approach (f)	Illiquid price differences between settlement points (g)	$(10) to $50/ MWh
Other (h)	15	(28)	(13)			
Total	$ 153	$ (288)	$ (135)			

December 31, 2017

	Fair Value					
Contract Type (a)	**Assets**	**Liabilities**	**Total**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**
Electricity purchases and sales	$ 12	$ (33)	$ (21)	Valuation Model	Hourly price curve shape (c)	$0 to $40/ MWh
					Illiquid delivery periods for ERCOT hub power prices and heat rates (d)	$20 to $70/ MWh
Electricity and weather options	—	(91)	(91)	Option Pricing Model	Gas to power correlation (e)	30% to 100%
					Power volatility (e)	5% to 180%
Financial transmission rights	45	(4)	41	Market Approach (f)	Illiquid price differences between settlement points (g)	$0 to $15/ MWh
Other (h)	18	—	18			
Total	$ 75	$ (128)	$ (53)			

(a) Electricity purchase and sales contracts include power and heat rate positions in ERCOT, PJM, NYISO, ISO-NE and MISO regions. The forward purchase contracts (swaps and options) used to hedge electricity price differences between settlement points within are referred to as congestion revenue rights in ERCOT and financial transmission rights in PJM, NYISO, ISO-NE and MISO regions. Electricity options consist of physical electricity options and spread options.
(b) The range of the inputs may be influenced by factors such as time of day, delivery period, season and location.
(c) Primarily based on the historical range of forward average hourly ERCOT North Hub prices.
(d) Primarily based on historical forward ERCOT power price and heat rate variability.
(e) Based on historical forward correlation and volatility within ERCOT.

(f) While we use the market approach, there is insufficient market data to consider the valuation liquid.
(g) Primarily based on the historical price differences between settlement points within ERCOT hubs and load zones.
(h) Other includes contracts for natural gas, coal options and emissions.

There were no transfers between Level 1 and Level 2 of the fair value hierarchy for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016. See the table below for discussion of transfers between Level 2 and Level 3 for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016.

The following table presents the changes in fair value of the Level 3 assets and liabilities for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016.

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Net asset (liability) balance at beginning of period (a)	$ (53)	$ 83	$ 81	$ 37
Total unrealized valuation gains (losses)	(363)	(136)	31	122
Purchases, issuances and settlements (b):				
Purchases	146	69	15	37
Issuances	(41)	(22)	(7)	(20)
Settlements	76	(106)	(30)	(51)
Transfers into Level 3 (c)	4	4	3	1
Transfers out of Level 3 (c)	133	71	(10)	1
Net liabilities assumed in connections with the Merger	(37)	—	—	—
Earn-out provision (d)	—	(16)	—	—
Net liabilities assumed in the Lamar and Forney Acquisition (Note 3) (e)	—	—	—	(30)
Net change (f)	(82)	(136)	2	60
Net asset (liability) balance at end of period	$ (135)	$ (53)	$ 83	$ 97
Unrealized valuation gains (losses) relating to instruments held at end of period	$ (174)	$ (98)	$ 28	$ 98

(a) The beginning balance for the Successor period from October 3, 2016 through December 31, 2016 reflects a $16 million adjustment to the fair value of certain Level 3 assets driven by power prices utilized by the Successor for unobservable delivery periods.
(b) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received.
(c) Includes transfers due to changes in the observability of significant inputs. All Level 3 transfers during the periods presented are in and out of Level 2. For the years ended December 31, 2018 and 2017, transfers out of Level 3 primarily consists of electricity derivatives where forward pricing inputs have become observable.
(d) Represents initial fair value of the earn-out provision agreed to as part of the Odessa Acquisition. See Note 3.
(e) Includes fair value of Level 3 assets and liabilities as of the purchase date and any related rolloff between the purchase date and the period ended October 2, 2016.
(f) Activity excludes change in fair value in the month positions settle. For the Successor period, substantially all changes in values of commodity contracts (excluding the net liabilities assumed in connection with the Merger and the initial fair value of the earn-out provision related to the Odessa Acquisition in 2017) are reported as operating revenues in our statements of consolidated income (loss). For the Predecessor period, substantially all changes in values of commodity contracts (excluding net liabilities assumed in the Lamar and Forney Acquisition in 2016) are reported as net gain from commodity hedging and trading activities in the statements of consolidated income (loss).

18. COMMODITY AND OTHER DERIVATIVE CONTRACTUAL ASSETS AND LIABILITIES

Strategic Use of Derivatives

We transact in derivative instruments, such as options, swaps, futures and forward contracts, to manage commodity price and interest rate risk. See Note 17 for a discussion of the fair value of derivatives.

Commodity Hedging and Trading Activity — We utilize natural gas and electricity derivatives to reduce exposure to changes in electricity prices primarily to hedge future revenues from electricity sales from our generation assets. We also utilize short-term electricity, natural gas, coal, fuel oil, uranium and emissions derivative instruments for fuel hedging and other purposes. Counterparties to these transactions include energy companies, financial institutions, electric utilities, independent power producers, oil and gas producers, local distribution companies and energy marketing companies. Unrealized gains and losses arising from changes in the fair value of derivative instruments as well as realized gains and losses upon settlement of the instruments are reported in our statements of consolidated income (loss) in operating revenues and fuel, purchased power costs and delivery fees in the Successor period and net gain from commodity hedging and trading activities in the Predecessor period.

Interest Rate Swaps — Interest rate swap agreements are used to reduce exposure to interest rate changes by converting floating-rate interest rates to fixed rates, thereby hedging future interest costs and related cash flows. Unrealized gains and losses arising from changes in the fair value of the swaps are reported in our statements of consolidated income (loss) in interest expense and related charges.

Financial Statement Effects of Derivatives

Substantially all derivative contractual assets and liabilities are accounted for under mark-to-market accounting consistent with accounting standards related to derivative instruments and hedging activities. The following tables provide detail of derivative contractual assets and liabilities as reported in our consolidated balance sheets at December 31, 2018 and 2017. Derivative asset and liability totals represent the net value of the contract, while the balance sheet totals represent the gross value of the contract.

	December 31, 2018				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 707	$ 22	$ 1	$ —	$ 730
Noncurrent assets	54	55	—	—	109
Current liabilities	—	—	(1,374)	(2)	(1,376)
Noncurrent liabilities	—	—	(238)	(32)	(270)
Net assets (liabilities)	$ 761	$ 77	$ (1,611)	$ (34)	$ (807)

	December 31, 2017				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 190	$ —	$ —	$ —	$ 190
Noncurrent assets	30	22	2	4	58
Current liabilities	—	(4)	(216)	(4)	(224)
Noncurrent liabilities	—	—	(102)	—	(102)
Net assets (liabilities)	$ 220	$ 18	$ (316)	$ —	$ (78)

At December 31, 2018 and 2017, there were no derivative positions accounted for as cash flow or fair value hedges.

The following table presents the pretax effect of derivative gains (losses) on net income, including realized and unrealized effects. Amount represents changes in fair value of positions in the derivative portfolio during the period, as realized amounts related to positions settled are assumed to equal reversals of previously recorded unrealized amounts.

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
Derivative (statements of consolidated income (loss) presentation)	2018	2017		
Commodity contracts (Operating revenues)	$ (855)	$ 56	$ (92)	$ —
Commodity contracts (Fuel, purchased power costs and delivery fees)	18	6	21	—
Commodity contracts (Net gain from commodity hedging and trading activities)	—	—	—	194
Interest rate swaps (Interest expense and related charges)	(11)	2	(11)	—
Net gain (loss)	$ (848)	$ 64	$ (82)	$ 194

In conjunction with fresh start reporting, the balances in accumulated other comprehensive income were eliminated from our consolidated balance sheet on the Effective Date. The pretax effect (all losses) on net income and other comprehensive income (OCI) of derivative instruments previously accounted for as cash flow hedges by the Predecessor was immaterial for the Predecessor period from January 1, 2016 through October 2, 2016. There were no amounts recognized in OCI for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016.

Balance Sheet Presentation of Derivatives

We elect to report derivative assets and liabilities in our consolidated balance sheets on a gross basis without taking into consideration netting arrangements we have with counterparties to those derivatives. We maintain standardized master netting agreements with certain counterparties that allow for the right to offset assets and liabilities and collateral in order to reduce credit exposure between us and the counterparty. These agreements contain specific language related to margin requirements, monthly settlement netting, cross-commodity netting and early termination netting, which is negotiated with the contract counterparty.

Generally, margin deposits that contractually offset these derivative instruments are reported separately in our consolidated balance sheets, with the exception of certain margin amounts related to changes in fair value on CME transactions that, beginning in January 2017, are legally characterized as settlement of forward exposure rather than collateral. Margin deposits received from counterparties are primarily used for working capital or other general corporate purposes.

The following tables reconcile our derivative assets and liabilities on a contract basis to net amounts after taking into consideration netting arrangements with counterparties and financial collateral:

	December 31, 2018				December 31, 2017			
	Derivative Assets and Liabilities	Offsetting Instruments (a)	Cash Collateral (Received) Pledged (b)	Net Amounts	Derivative Assets and Liabilities	Offsetting Instruments (a)	Cash Collateral (Received) Pledged (b)	Net Amounts
Derivative assets:								
Commodity contracts	$ 761	$ (593)	$ (1)	$ 167	$ 220	$ (113)	$ (1)	$ 106
Interest rate swaps	77	(26)	—	51	18	—	—	18
Total derivative assets	838	(619)	(1)	218	238	(113)	(1)	124
Derivative liabilities:								
Commodity contracts	(1,611)	593	109	(909)	(316)	113	1	(202)
Interest rate swaps	(34)	26	—	(8)	—	—	—	—
Total derivative liabilities	(1,645)	619	109	(917)	(316)	113	1	(202)
Net amounts	$ (807)	$ —	$ 108	$ (699)	$ (78)	$ —	$ —	$ (78)

(a) Amounts presented exclude trade accounts receivable and payable related to settled financial instruments.
(b) Represents cash amounts received or pledged pursuant to a master netting arrangement, including fair value-based margin requirements.

Derivative Volumes

The following table presents the gross notional amounts of derivative volumes at December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017	
Derivative type	Notional Volume		Unit of Measure
Natural gas (a)	7,011	1,259	Million MMBtu
Electricity	317,572	114,129	GWh
Financial Transmission Rights (b)	172,611	110,913	GWh
Coal	45	2	Million U.S. tons
Fuel oil	60	5	Million gallons
Uranium	50	325	Thousand pounds
Emissions	10	—	Million tons
Interest rate swaps – floating/fixed (c)	$ 7,717	$ 3,000	Million U.S. dollars

(a) Represents gross notional forward sales, purchases and options transactions, locational basis swaps and other natural gas transactions.
(b) Represents gross forward purchases associated with instruments used to hedge electricity price differences between settlement points within ISOs or RTOs.
(c) Includes notional amounts of interest rate swaps with maturity dates through July 2026.

__Credit Risk-Related Contingent Features of Derivatives__

Our derivative contracts may contain certain credit risk-related contingent features that could trigger liquidity requirements in the form of cash collateral, letters of credit or some other form of credit enhancement. Certain of these agreements require the posting of collateral if our credit rating is downgraded by one or more credit rating agencies or include cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

The following table presents the commodity derivative liabilities subject to credit risk-related contingent features that are not fully collateralized:

	December 31, 2018	December 31, 2017
Fair value of derivative contract liabilities (a)	$ (856)	$ (204)
Offsetting fair value under netting arrangements (b)	218	103
Cash collateral and letters of credit	190	41
Liquidity exposure	$ (448)	$ (60)

(a) Excludes fair value of contracts that contain contingent features that do not provide specific amounts to be posted if features are triggered, including provisions that generally provide the right to request additional collateral (material adverse change, performance assurance and other clauses).

(b) Amounts include the offsetting fair value of in-the-money derivative contracts and net accounts receivable under master netting arrangements.

__Concentrations of Credit Risk Related to Derivatives__

We have concentrations of credit risk with the counterparties to our derivative contracts. At December 31, 2018, total credit risk exposure to all counterparties related to derivative contracts totaled $1.095 billion (including associated accounts receivable). The net exposure to those counterparties totaled $344 million at December 31, 2018 after taking into effect netting arrangements, setoff provisions and collateral, with the largest net exposure to a single counterparty totaling $78 million. At December 31, 2018, the credit risk exposure to the banking and financial sector represented 62% of the total credit risk exposure and 22% of the net exposure.

Exposure to banking and financial sector counterparties is considered to be within an acceptable level of risk tolerance because all of this exposure is with counterparties with investment grade credit ratings. However, this concentration increases the risk that a default by any of these counterparties would have a material effect on our financial condition, results of operations and liquidity. The transactions with these counterparties contain certain provisions that would require the counterparties to post collateral in the event of a material downgrade in their credit rating.

We maintain credit risk policies with regard to our counterparties to minimize overall credit risk. These policies authorize specific risk mitigation tools including, but not limited to, use of standardized master agreements that allow for netting of positive and negative exposures associated with a single counterparty. Credit enhancements such as parent guarantees, letters of credit, surety bonds, liens on assets and margin deposits are also utilized. Prospective material changes in the payment history or financial condition of a counterparty or downgrade of its credit quality result in the reassessment of the credit limit with that counterparty. The process can result in the subsequent reduction of the credit limit or a request for additional financial assurances. An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts are owed to the counterparties related to the derivative contracts or delays in receipts of expected settlements if the counterparties owe amounts to us.

19. PENSION AND OTHER POSTRETIREMENT EMPLOYEE BENEFITS (OPEB) PLANS

On the Effective Date, the EFH Retirement Plan was transferred to Vistra Energy pursuant to a separation agreement between Vistra Energy and EFH Corp. As of the Effective Date, Vistra Energy is the plan sponsor of the Vistra Energy Retirement Plan (the Retirement Plan), which provides benefits to eligible employees of its subsidiaries. Oncor is a participant in the Retirement Plan. As Vistra Energy accounts for its interests in the Retirement Plan as a multiple employer plan, only Vistra Energy's share of the plan assets and obligations are reported in the pension benefit information presented below. After amendments in 2012, employees in the Retirement Plan now consist entirely of active and retired collective bargaining unit employees. The Retirement Plan is a qualified defined benefit pension plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and is subject to the provisions of ERISA. The Retirement Plan provides benefits to participants under one of two formulas: (i) a Cash Balance Formula under which participants earn monthly contribution credits based on their compensation and a combination of their age and years of service, plus monthly interest credits or (ii) a Traditional Retirement Plan Formula based on years of service and the average earnings of the three years of highest earnings. Under the Cash Balance Formula, future increases in earnings will not apply to prior service costs. It is our policy to fund the Retirement Plan assets only to the extent required under existing federal regulations.

Vistra Energy and our participating subsidiaries offer other postretirement employee benefits (OPEB) in the form of certain health care and life insurance benefits to eligible retirees and their eligible dependents. The retiree contributions required for such coverage vary based on a formula depending on the retiree's age and years of service.

Prior to the Merger, Dynegy provided pension and OPEB benefits to certain of its employees and retirees. At the Merger Date, Vistra Energy assumed these plans and the excess of the benefit obligations over the fair value of plan assets was recognized as a liability (see Note 2). Benefit obligations assumed totaled $539 million and the fair value of plan assets assumed totaled $459 million, and the net unfunded liability was recorded as $15 million to other noncurrent assets, $2 million to other current liabilities and $93 million to other noncurrent liabilities in the consolidated balance sheets.

Effective January 1, 2018, Vistra Energy entered into a contractual arrangement with Oncor whereby the costs associated with providing OPEB coverage for certain retirees (Split Participants) whose employment included service with both the regulated businesses of Oncor (or its predecessors) and the non-regulated businesses of Vistra Energy (or its predecessors) are split between Oncor and Vistra Energy. Prior to January 1, 2018, coverage for Split Participants was provided by the Oncor OPEB plan, with Vistra Energy retaining its portion of the liability for coverage for Split Participants. In addition, Vistra Energy is the sponsor of an OPEB plan that certain EFH Corp. retirees participate in. As Vistra Energy accounts for its interest in these OPEB plans as multiple employer plans, only Vistra Energy's share of the plan assets and obligations are reported in the OPEB information presented below.

Pension and OPEB Costs

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
Pension costs	$ 14	$ 6	$ 2	$ 4
OPEB costs	9	6	2	—
Total benefit costs recognized as expense	$ 23	$ 12	$ 4	$ 4

Market-Related Value of Assets Held in Postretirement Benefit Trusts

We use the calculated value method to determine the market-related value of the assets held in the trust for purposes of calculating pension costs. We include all gains or losses in the market-related value of assets over a rolling four-year period. Each year, 25% of such gains and losses for the current year and for each of the preceding three years is included in the market-related value. Each year, the market-related value of assets is increased for contributions to the plan and investment income and is decreased for benefit payments and expenses for that year.

Detailed Information Regarding Pension Benefits

The following information is based on a December 31, 2018, 2017 and 2016 measurement dates:

	Successor		
	Year Ended December 31, 2018	**Year Ended December 31, 2017**	**Period from October 3, 2016 through December 31, 2016**
Assumptions Used to Determine Net Periodic Pension Cost:			
Discount rate (Vistra Energy Plan)	3.74%	4.31%	3.79%
Discount rate (Dynegy Plan & EEI Plan)	4.05%	—%	—%
Expected return on plan assets (Vistra Energy Plan)	4.56%	4.86%	4.89%
Expected return on plan assets (Dynegy Plan)	5.94%	—%	—%
Expected return on plan assets (EEI Plan)	4.74%	—%	—%
Expected rate of compensation increase (Vistra Energy Plan)	3.62%	3.50%	3.50%
Expected rate of compensation increase (Dynegy Plan & EEI Plan)	3.50%	—%	—%
Interest crediting rate for cash balance plans (Vistra Energy Plan)	3.50%	4.00%	4.00%
Interest crediting rate for cash balance plans (Dynegy Plan & EEI Plan)	4.25%	—%	—%
Components of Net Pension Cost:			
Service cost	$ 15	$ 5	$ 2
Interest cost	21	6	1
Expected return on assets	(23)	(5)	(1)
Immediate pension cost	$ 1	$ —	$ —
Net periodic pension cost	$ 14	$ 6	$ 2
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:			
Net (gain) loss	$ 14	$ 3	$ (4)
Total recognized in net periodic benefit cost and other comprehensive income	$ 28	$ 9	$ (2)
Assumptions Used to Determine Benefit Obligations:			
Discount rate (Vistra Plan)	4.37%	3.74%	4.31%
Expected rate of compensation increase (Vistra Plan)	3.35%	3.62%	3.50%
Discount rate (Dynegy Plan)	4.37%	—%	—%
Expected rate of compensation increase (Dynegy Plan)	3.35%	—%	—%
Interest crediting rate for cash balance plans (Vistra Energy Plan)	3.50%	3.50%	4.00%
Interest crediting rate for cash balance plans (Dynegy Plan & EEI)	3.50%	—%	—%

For the year ended December 31, 2018, the net actuarial loss of $14 million was driven by losses attributable to actual asset performance falling short of expectations and plan experience different than expected, partially offset by gains attributable to increasing discount rates due to changes in the corporate bond markets, economic assumption updates to reflect current market conditions and life expectancy projection updates.

For the year ended December 31, 2017, the net actuarial loss of $3 million was driven by losses attributable to decreasing discount rates due to changes in the corporate bond markets and demographic assumption updates to reflect current expectations, partially offset by gains attributable to actual asset performance exceeding expectations, economic assumption updates to reflect current market conditions, life expectancy projection updates and plan experience different than expected.

For the period from October 3, 2016 through December 31, 2016, the net actuarial gain of $4 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets and plan experience different than expected, partially offset by losses attributable to actual asset performance falling short of expectations.

	Successor	
	Year Ended December 31,	
	2018	2017
Change in Pension Obligation:		
Projected benefit obligation at beginning of period	$ 163	$ 144
Acquisitions	502	—
Service cost	15	5
Interest cost	21	6
Settlement	(28)	—
Actuarial (gain) loss	(34)	13
Benefits paid	(24)	(5)
Projected benefit obligation at end of year	$ 615	$ 163
Accumulated benefit obligation at end of year	$ 611	$ 157
Change in Plan Assets:		
Fair value of assets at beginning of period	$ 128	$ 117
Acquisitions	428	—
Employer contributions	12	—
Settlement	(28)	—
Actual gain (loss) on assets	(26)	16
Benefits paid	(24)	(5)
Fair value of assets at end of year	$ 490	$ 128
Funded Status:		
Projected pension benefit obligation	$ (615)	$ (163)
Fair value of assets	490	128
Funded status at end of year	$ (125)	$ (35)
Amounts Recognized in the Balance Sheet Consist of:		
Other current liabilities	$ —	$ —
Other noncurrent liabilities	(125)	(35)
Net liability recognized	$ (125)	$ (35)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:		
Net gain (loss)	$ (13)	$ 1

The following table provides information regarding pension plans with projected benefit obligation (PBO) and accumulated benefit obligation (ABO) in excess of the fair value of plan assets.

	December 31,	
	2018	2017
Pension Plans with PBO and ABO in Excess Of Plan Assets:		
Projected benefit obligations	$ 615	$ 163
Accumulated benefit obligation	$ 611	$ 157
Plan assets	$ 490	$ 128

Pension Plan Investment Strategy and Asset Allocations

Our investment objective for the Retirement Plan is to invest in a suitable mix of assets to meet the future benefit obligations at an acceptable level of risk, while minimizing the volatility of contributions. Fixed income securities held primarily consist of corporate bonds from a diversified range of companies, U.S. Treasuries and agency securities and money market instruments. Equity securities are held to enhance returns by participating in a wide range of investment opportunities. International equity securities are used to further diversify the equity portfolio and may include investments in both developed and emerging markets.

The target asset allocation ranges of pension plan investments by asset category are as follows:

	Target Allocation Ranges		
Asset Category:	Vistra Energy Plan	Dynegy Plan	EEI Plan
Fixed income	65% - 75%	45% - 55%	43% - 53%
Global equity securities	16% - 24%	29% - 37%	30% - 38%
Real estate	4% - 8%	8% - 12%	9% - 13%
Credit strategies	3% - 7%	6% - 10%	6% - 10%

Expected Long-Term Rate of Return on Assets Assumption

The Retirement Plan strategic asset allocation is determined in conjunction with the plan's advisors and utilizes a comprehensive Asset-Liability modeling approach to evaluate potential long-term outcomes of various investment strategies. The study incorporates long-term rate of return assumptions for each asset class based on historical and future expected asset class returns, current market conditions, rate of inflation, current prospects for economic growth, and taking into account the diversification benefits of investing in multiple asset classes and potential benefits of employing active investment management.

	Retirement Plan		
	Expected Long-Term Rate of Return		
Asset Class:	Vistra Energy Plan	Dynegy Plan	EEI Plan
Fixed income securities	4.0%	3.9%	3.9%
Global equity securities	7.5%	7.5%	7.5%
Real estate	5.4%	5.4%	5.4%
Credit strategies	6.8%	6.8%	6.8%
Weighted average	4.8%	5.3%	5.6%

Fair Value Measurement of Pension Plan Assets

At December 31, 2018 and 2017, the Retirement Plan assets measured at fair value on a recurring basis consisted of the following:

	December 31,			
	2018			2017
	Level 1	Level 2	Total	Level 2
Asset Category:				
Interest-bearing cash	$ —	$ (6)	$ (6)	$ (7)
Fixed income securities:				
Corporate bonds (a)	57	61	118	65
U.S. Treasuries	—	25	25	29
Other (b)	—	6	6	7
Total assets categorized as Level 1 or 2	57	86	143	94
Assets measured at net asset value (c):				
Commingled trusts			18	2
Equity securities:				
U.S.			119	14
International			73	13
Fixed income securities:				
Corporate bonds (a)			137	5
Total assets measured at net asset value			347	34
Total assets			$ 490	$ 128

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(a) Substantially all corporate bonds are rated investment grade by a major ratings agency such as Moody's.
(b) Other consists primarily of taxable municipal bonds.
(c) Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this line are intended to permit reconciliation of the fair value hierarchy to total Vistra Retirement Plan assets.

Detailed Information Regarding Postretirement Benefits Other Than Pensions

The following OPEB information is based on a December 31, 2018 measurement date:

	Successor		
	Year Ended December 31, 2018	**Year Ended December 31, 2017**	**Period from October 3, 2016 through December 31, 2016**
Assumptions Used to Determine Net Periodic Benefit Cost:			
Discount rate (Vistra Energy Plan)	3.67%	4.11%	4.00%
Discount rate (Oncor Plan)	—%	4.18%	3.69%
Discount rate (Dynegy Plan)	4.04%	—%	—%
Expected return on plan assets (EEI Union)	5.10%	—%	—%
Expected return on plan assets (EEI Salaried)	4.47%	—%	—%
Components of Net Postretirement Benefit Cost:			
Service cost	$ 2	$ 2	$ 1
Interest cost	5	4	1
Expected return on plan assets	(1)	—	—
Amortization of unrecognized amounts	3	—	—
Plan amendments (a)	—	—	(4)
Net periodic OPEB cost (income)	$ 9	$ 6	$ (2)
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:			
Net (gain) loss and prior service (credit) cost	$ (6)	$ 26	$ (5)
Total recognized in net periodic benefit cost and other comprehensive income	$ 3	$ 32	$ (7)
Assumptions Used to Determine Benefit Obligations at Period End:			
Discount rate (Vistra Energy Plan)	4.35%	3.67%	4.11%
Discount rate (Split-Participant Plan)	4.35%	3.67%	—%
Discount rate (Oncor Plan)	—%	—%	4.18%
Discount rate (Dynegy Plan)	4.35%	—%	—%
Expected return on plan assets (EEI Union)	5.36%	—%	—%
Expected return on plan assets (EEI Salaried)	4.70%	—%	—%

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(a) Curtailment gain recognized as other income in the statements of consolidated income (loss) as a result of discontinued life insurance benefits for active employees.

For the year ended December 31, 2018, the net actuarial gain of $7 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets, life expectancy projection updates and updates to health care related assumptions, partially offset by losses attributable to actual asset performance falling short of expectations and plan experience different than expected.

For the year ended December 31, 2017, the net actuarial loss of $15 million was driven by losses attributable to decreasing discount rates due to changes in the corporate bond markets, demographic assumption updates to reflect current expectations and updates to health care related assumptions, partially offset by gains attributable to life expectancy projection updates and plan experience different than expected.

For the period from October 3, 2016 through December 31, 2016, the net actuarial gain of $5 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets and plan experience different than expected.

	Year Ended December 31,	
	2018	2017
Change in Postretirement Benefit Obligation:		
Benefit obligation at beginning of year	$ 115	$ 88
Acquisition	37	—
Service cost	2	2
Interest cost	5	4
Participant contributions	2	2
Plan amendments (a)	4	11
Actuarial (gain) loss	(9)	15
Benefits paid	(12)	(7)
Benefit obligation at end of year	$ 144	$ 115
Change in Plan Assets:		
Fair value of assets at beginning of year	$ —	$ —
Acquisition	32	—
Employer contributions	8	5
Participant contributions	2	2
Benefits paid	(12)	(7)
Actual loss on assets	(1)	—
Fair value of assets at end of year	$ 29	$ —
Funded Status:		
Benefit obligation	$ (144)	$ (115)
Fair value of assets	29	—
Funded status at end of year	$ (115)	$ (115)
Amounts Recognized on the Balance Sheet Consist of:		
Other noncurrent assets	$ 14	$ —
Other current liabilities	$ (8)	$ (6)
Other noncurrent liabilities	(121)	(109)
Net liability recognized	$ (115)	$ (115)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:		
Net loss and prior service cost	$ 15	$ 20

(a) For the year ended December 31, 2018, plan amendments relate to changes in Dynegy plans and retiree medical cost structure. For the year ended December 31, 2017, plan amendments relate to the contractual arrangement with Oncor covering Split Participants.

The following tables provide information regarding the assumed health care cost trend rates.

	Successor	
	December 31, 2018	December 31, 2017
Assumed Health Care Cost Trend Rates-Not Medicare Eligible:		
Health care cost trend rate assumed for next year	6.70%	7.00%
Rate to which the cost trend is expected to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2026	2026
Assumed Health Care Cost Trend Rates-Medicare Eligible:		
Health care cost trend rate assumed for next year	9.90%	10.66%
Rate to which the cost trend is expected to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2027	2026

Fair Value Measurement of OPEB Plan Assets

At December 31, 2018, the Vistra Energy OPEB plan assets measured at fair value on a recurring basis totaled $29 million and consisted of $21 million of U.S equities classified as Level 1 and $8 million of U.S. Treasuries classified as Level 2.

Significant Concentrations of Risk

The plans' investments are exposed to risks such as interest rate, capital market and credit risks. We seek to optimize return on investment consistent with levels of liquidity and investment risk which are prudent and reasonable, given prevailing capital market conditions and other factors specific to us. While we recognize the importance of return, investments will be diversified in order to minimize the risk of large losses unless, under the circumstances, it is clearly prudent not to do so. There are also various restrictions and guidelines in place including limitations on types of investments allowed and portfolio weightings for certain investment securities to assist in the mitigation of the risk of large losses.

Assumed Discount Rate

We selected the assumed discount rate using the Aon AA Above Median yield curve, which is based on corporate bond yields and at December 31, 2018 consisted of 377 corporate bonds with an average rating of AA using Moody's, Standard & Poor's Rating Services and Fitch Ratings, Ltd. ratings.

Contributions

Successor — For the Successor period for the year ended December 31, 2018, a contribution totaling $12 million was made to the Retirement Plan. No contributions were made to the Retirement Plan for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016. No contributions to the Retirement Plan are expected to be made in 2019. OPEB plan funding for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 totaled $8 million, $5 million and $1 million, respectively, and funding in 2019 is expected to total $8 million.

Predecessor — In September 2016, a cash contribution totaling $2 million was made to the EFH Retirement Plan, all of which was contributed by our Predecessor. OPEB plan funding for the Predecessor period from January 1, 2016 through October 2, 2016 totaled $3 million.

Future Benefit Payments

Estimated future benefit payments to beneficiaries are as follows:

	2019	2020	2021	2022	2023	2024-28
Pension benefits	$ 46	$ 45	$ 46	$ 46	$ 46	$ 216
OPEB	$ 10	$ 11	$ 11	$ 11	$ 11	$ 49

Qualified Savings Plans

Our employees may participate in a qualified savings plan (the Thrift Plan). This plan is a participant-directed defined contribution plan intended to qualify under Section 401(a) of the Code and is subject to the provisions of ERISA. Under the terms of the Thrift Plan, employees who do not earn more than the IRS threshold compensation limit used to determine highly compensated employees may contribute, through pre-tax salary deferrals and/or after-tax payroll deductions, the lesser of 75% of their regular salary or wages or the maximum amount permitted under applicable law. Employees who earn more than such threshold may contribute from 1% to 20% of their regular salary or wages. Employer matching contributions are also made in an amount equal to 100% (75% for employees covered under the Traditional Retirement Plan Formula) of the first 6% of employee contributions. Employer matching contributions are made in cash and may be allocated by participants to any of the plan's investment options.

At the Merger Date, Vistra Energy assumed Dynegy's participant-directed defined contribution plan. In January 2019, this plan was merged into the Thrift Plan.

Aggregate employer contributions to the qualified savings plans totaled $24 million, $19 million, $5 million and $16 million for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively.

20. STOCK-BASED COMPENSATION

Vistra Energy 2016 Omnibus Incentive Plan

On the Effective Date, the Vistra Energy board of directors (Board) adopted the 2016 Omnibus Incentive Plan (2016 Incentive Plan), under which an aggregate of 22,500,000 shares of our common stock were reserved for issuance as equity-based awards to our non-employee directors, employees, and certain other persons. The Board or any committee duly authorized by the Board will administer the 2016 Incentive Plan and has broad authority under the 2016 Incentive Plan to, among other things: (a) select participants, (b) determine the types of awards that participants are to receive and the number of shares that are to be subject to such awards and (c) establish the terms and conditions of awards, including the price (if any) to be paid for the shares of the award. The types of awards that may be granted under the 2016 Incentive Plan include stock options, RSUs, restricted stock, performance awards and other forms of awards granted or denominated in shares of Vistra Energy common stock, as well as certain cash-based awards.

If any stock option or other stock-based award granted under the 2016 Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of shares of Vistra Energy common stock underlying any unexercised award shall again be available for awards under the 2016 Incentive Plan. If any shares of restricted stock, performance awards or other stock-based awards denominated in shares of Vistra Energy common stock awarded under the 2016 Incentive Plan are forfeited for any reason, the number of forfeited shares shall again be available for purposes of awards under the 2016 Incentive Plan. Any award under the 2016 Incentive Plan settled in cash shall not be counted against the maximum share limitation.

As is customary in incentive plans of this nature, each share limit and the number and kind of shares available under the 2016 Incentive Plan and any outstanding awards, as well as the exercise or purchase price of awards, and performance targets under certain types of performance-based awards, are required to be adjusted in the event of certain reorganizations, mergers, combinations, recapitalizations, stock splits, stock dividends or other similar events that change the number or kind of shares outstanding, and extraordinary dividends or distributions of property to the Vistra Energy stockholders.

Assumption of Dynegy Stock Compensation Plans

At the Merger Date, Dynegy stock options and equity-based awards outstanding immediately prior to the Merger Date were generally automatically converted upon completion of the Merger into stock options and equity-based awards, respectively, with respect to Vistra Energy's common stock, after giving effect to the Exchange Ratio.

Instrument Type	Dynegy Awards Prior to the Merger Date	Vistra Awards Converted at the Merger Date	Fair Value of Awards (a)
Stock Options	4,096,027	2,670,610	$ 10
Restricted Stock Units	5,718,148	3,056,689	61
Performance Units	1,538,133	938,721	18
Total			$ 89

(a) $26 million was attributable to pre-combination service and considered part of the purchase price (see Note 2). $33 million was recognized immediately as compensation expense due to accelerated vesting as a result of the Merger. $30 million will be amortized as compensation expense over the remaining service period and is recorded in additional paid in capital in the consolidated balance sheet.

Stock-Based Compensation Expense

Stock-based compensation expense is reported as SG&A in the statement of consolidated net income (loss) as follows:

	Successor		
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016
	2018	2017	
Total stock-based compensation expense	$ 73	$ 19	$ 3
Income tax benefit	(15)	(7)	(1)
Stock based-compensation expense, net of tax	$ 58	$ 12	$ 2

Stock Options

The fair value of each stock option is estimated on the date of grant using a Black-Scholes option-pricing model. The risk-free interest rate used in the option valuation model was based on yields available on the grant dates for U.S. Treasury Strips with maturity consistent with the expected life assumption. The expected term of the option represents the period of time that options granted are expected to be outstanding and is based on the SEC Simplified Method (midpoint of average vesting time and contractual term). Expected volatility is based on an average of the historical, daily volatility of a peer group selected by Vistra Energy over a period consistent with the expected life assumption ending on the grant date. We assumed no dividend yield in the valuation of the options. These options may be exercised over either three- or four-year graded vesting periods and will expire 10 years from the grant date.

The 2016 Incentive Plan includes an anti-dilutive provision that requires any outstanding option awards to be adjusted for the effect of equity restructurings. In March 2017, the Board declared that the exercise price of each outstanding option be reduced by $2.32, the amount per share of common stock related to the Special Dividend (see Note 16).

Issuance of Merger-related Stock Options — At the Merger Date, we issued 5.2 million stock options to certain members of management, which are subject to performance and service conditions for vesting. The performance condition is based on the Company's achievement of certain merger related targets measured as of December 31, 2019. Compensation cost has been recognized in 2018 based on graded vesting over 4 and 5 years since the date of issuance because we estimate achievement of the target is likely to occur.

Stock options outstanding at December 31, 2018 are all held by current employees. The following table summarizes our stock option activity:

	Successor			
	Year Ended December 31, 2018			
	Stock Options (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Total outstanding at beginning of period	8,136	$ 14.44	9.0	$ 32.4
Awards converted at Merger Date	2,671	$ 23.19		
Granted	5,268	$ 19.67		
Exercised	(1,082)	$ 13.91		
Forfeited or expired	(494)	$ 15.14		
Total outstanding at end of period	14,499	$ 17.97	7.3	$ 85.1
Exercisable at December 31, 2018	4,696	$ 18.88	5.2	$ 32.6

At December 31, 2018, $48 million of unrecognized compensation cost related to unvested stock options granted under the 2016 Incentive Plan are expected to be recognized over a weighted average period of approximately 3 years.

Restricted Stock Units

The following table summarizes our restricted stock unit activity:

	Successor			
	Year Ended December 31, 2018			
	Restricted Stock Units (in thousands)	Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Total outstanding at beginning of period	2,375	$ 16.91	1.9	$ 43.5
Awards converted at Merger Date	3,057	$ 15.52		
Granted	133	$ 22.41		
Exercised	(2,114)	$ 15.48		
Forfeited or expired	(225)	$ 16.69		
Total outstanding at end of period	3,226	$ 16.77	1.1	$ 73.8
Expected to vest	3,222	$ 16.85	1.0	$ 73.7

At December 31, 2018, $40 million of unrecognized compensation cost related to unvested restricted stock units granted under the 2016 Incentive Plan are expected to be recognized over a weighted average period of approximately 3 years.

Performance Stock Units

In October 2017, we issued Performance Stock Units (PSUs) to certain members of management. As of December 31, 2018, we had not yet established the significant terms of the PSUs relevant to vesting (scorecard, thresholds, and targets) for the entire measurement period; therefore, a grant date for financial accounting purposes has not occurred.

21. RELATED PARTY TRANSACTIONS

Successor

In connection with Emergence, we entered into agreements with certain of our affiliates and with parties who received shares of common stock and TRA Rights in exchange for their claims.

Registration Rights Agreement

Pursuant to the Plan of Reorganization, on the Effective Date, we entered into a Registration Rights Agreement (the Registration Rights Agreement) with certain selling stockholders providing for registration of the resale of the Vistra Energy common stock held by such selling stockholders.

In December 2016, we filed a Form S-1 registration statement with the SEC to register for resale the shares of Vistra Energy common stock held by certain significant stockholders pursuant to the Registration Rights Agreement, which was declared effective by the SEC in May 2017. The registration statement was amended in March 2018. Pursuant to the Registration Rights Agreement, in June 2018, we filed a post-effective amendment to the Form S-1 registration statement on Form S-3, which was declared effective by the SEC in July 2018. Among other things, under the terms of the Registration Rights Agreement:

- if we propose to file certain types of registration statements under the Securities Act with respect to an offering of equity securities, we will be required to use our reasonable best efforts to offer the other parties to the Registration Rights Agreement the opportunity to register all or part of their shares on the terms and conditions set forth in the Registration Rights Agreement; and

- the selling stockholders received the right, subject to certain conditions and exceptions, to request that we file registration statements or amend or supplement registration statements, with the SEC for an underwritten offering of all or part of their respective shares of Vistra Energy common stock (a Demand Registration), and the Company is required to cause any such registration statement or amendment or supplement (a) to be filed with the SEC promptly and, in any event, on or before the date that is 45 days, in the case of a registration statement on Form S-1, or 30 days, in the case of a registration statement on Form S-3, after we receive the written request from the relevant selling stockholders to effectuate the Demand Registration and (b) to become effective as promptly as reasonably practicable and in any event no later than 120 days after it is initially filed.

All expenses of registration under the Registration Rights Agreement, including the legal fees of one counsel retained by or on behalf of the selling stockholders, will be paid by us. Legal fee expenses paid or accrued by Vistra Energy on behalf of the selling stockholders totaled less than $1 million during each of the years ended December 31, 2018 and 2017.

Tax Receivable Agreement

On the Effective Date, Vistra Energy entered into the TRA with a transfer agent on behalf of certain former first lien creditors of TCEH. See Note 10 for discussion of the TRA.

Share Repurchase Transaction

In November 2018, the disinterested members of the Board considered and approved (in accordance with the Company's corporate governance guidelines) a share repurchase transaction, whereby Apollo Management Holdings L.P. (Apollo) and the Company, in a privately negotiated transaction, agreed for the Company to directly repurchase 5 million shares from Apollo. This purchase was part of Apollo's larger, 17 million share block trade, with the remaining 12 million shares being sold in a separate unregistered Rule 144 secondary block trade to a broker-dealer, who placed all 12 million shares with institutional investors. The Company repurchased the 5 million shares at the same discounted price (discounted from the November 19, 2018 closing price) that the participating broker paid for the 12 million shares it purchased, and the Company did not pay any additional fees to the participating broker for the 5 million shares it repurchased.

Predecessor

See Note 5 for a discussion of certain agreements entered into on the Effective Date between EFH Corp. and Vistra Energy with respect to the separation of the entities, including a separation agreement, a transition services agreement and a tax matters agreement.

The following represent our Predecessor's significant related-party transactions. As of the Effective Date, pursuant to the Plan of Reorganization, the Sponsor Group, EFH Corp., EFIH, Oncor Holdings and Oncor ceased being affiliates of Vistra Energy and its subsidiaries, including the TCEH Debtors and the Contributed EFH Debtors.

- Our retail operations (and prior to the Effective Date, our Predecessor) pay Oncor for services it provides, principally the delivery of electricity. Expenses recorded for these services, reported in fuel, purchased power costs and delivery fees, totaled $700 million for the Predecessor period from January 1, 2016 through October 2, 2016.

- A former subsidiary of EFH Corp. billed our Predecessor's subsidiaries for information technology, financial, accounting and other administrative services at cost. These charges, which are largely settled in cash and primarily reported in SG&A expenses, totaled $157 million for the Predecessor period from January 1, 2016 through October 2, 2016.

- Under Texas regulatory provisions, the trust fund for decommissioning the Comanche Peak nuclear generation facility is funded by a delivery fee surcharge billed to REPs by Oncor, as collection agent, and remitted monthly to Vistra Energy (and prior to the Effective Date, our Predecessor) for contribution to the trust fund with the intent that the trust fund assets, reported in other investments in our consolidated balance sheets, will ultimately be sufficient to fund the future decommissioning liability, reported in asset retirement obligations in our consolidated balance sheets. The delivery fee surcharges remitted to our Predecessor totaled $15 million for the Predecessor period from January 1, 2016 through October 2, 2016. Income and expenses associated with the trust fund and the decommissioning liability incurred by Vistra Energy (and prior to the Effective Date, our Predecessor) are offset by a net change in a receivable/payable that ultimately will be settled through changes in Oncor's delivery fee rates.

- EFH Corp. files consolidated federal income tax and Texas state margin tax returns that included our results prior to the Effective Date; however, under a Federal and State Income Tax Allocation Agreement, our federal income tax and Texas margin tax expense and related balance sheet amounts, including income taxes payable to or receivable from EFH Corp., were recorded as if our Predecessor filed its own corporate income tax return. For the Predecessor period from January 1, 2016 through October 2, 2016, our Predecessor made income tax payments to EFH Corp. totaling $22 million.

- Contributions to the EFH Corp. retirement plan by both Oncor and TCEH in 2014, 2015 and 2016 resulted in the EFH Corp. retirement plan being fully funded as calculated under the provisions of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In September 2016, a cash contribution totaling $2 million was made to the EFH Corp. retirement plan, all of which was contributed by TCEH, which resulted in the EFH Retirement Plan continuing to be fully funded as calculated under the provisions of ERISA. On the Effective Date, the EFH Retirement Plan was transferred to Vistra Energy pursuant to a separation agreement between Vistra Energy and EFH Corp.

- In 2007, TCEH entered into the TCEH Senior Secured Facilities with syndicates of financial institutions and other lenders. These syndicates included affiliates of GS Capital Partners, which is a member of the Sponsor Group. Affiliates of each member of the Sponsor Group have from time to time engaged in commercial banking transactions with TCEH and/or provided financial advisory services to TCEH, in each case in the normal course of business.

- Affiliates of GS Capital Partners were parties to certain commodity and interest rate hedging transactions with our Predecessor in the normal course of business.

- Affiliates of the Sponsor Group have sold or acquired debt or debt securities issued by our Predecessor in open market transactions or through loan syndications.

22. SEGMENT INFORMATION

The operations of Vistra Energy are aligned into six reportable business segments: (i) Retail, (ii) ERCOT, (iii) PJM, (iv) NY/NE, (v) MISO and (vi) Asset Closure. Our chief operating decision maker reviews the results of these segments separately and allocates resources to the respective segments as part of our strategic operations.

The Retail segment is engaged in retail sales of electricity and related services to residential, commercial and industrial customers. Substantially all of these activities are conducted by TXU Energy and Value Based Brands in Texas, Dynegy Energy Services in Massachusetts, Ohio, Illinois and Pennsylvania and Homefield Energy in Illinois. Prior to the Merger, the Retail segment was referred to as the Retail Electricity segment.

The ERCOT, PJM, NY/NE (comprising NYISO and ISO-NE) and MISO segments are engaged in electricity generation, wholesale energy sales and purchases, commodity risk management activities, fuel production and fuel logistics management, all largely within their respective ISO market. The PJM, NY/NE and MISO segments were established on the Merger Date to reflect markets served by businesses acquired in the Merger. Prior to the Merger, the ERCOT segment was referred to as the Wholesale Generation segment.

As discussed in Note 1, the Asset Closure segment was established effective January 1, 2018. The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines. Separately reporting the Asset Closure segment provides management with better information related to the performance and earnings power of Vistra Energy's ongoing operations and facilitates management's focus on minimizing the cost associated with decommissioning and reclamation of retired plants and mines. We have not allocated any unrealized gains or losses on commodity risk management activities to the Asset Closure segment for the generation plants that were retired in January, February and May 2018.

Corporate and Other represents the remaining non-segment operations consisting primarily of (i) general corporate expenses, interest, taxes and other expenses related to our support functions that provide shared services to our operating segments and (ii) CAISO operations.

Except as noted in Note 1, the accounting policies of the business segments are the same as those described in the summary of significant accounting policies in Note 1. Our chief operating decision maker uses more than one measure to assess segment performance, including segment net income (loss), which is the measure most comparable to consolidated net income (loss) prepared based on US GAAP. We account for intersegment sales and transfers as if the sales or transfers were to third parties, that is, at market prices. Certain shared services costs are allocated to the segments.

	Successor		
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016
Operating revenues (a)			
Retail	$ 5,597	$ 4,058	$ 912
ERCOT	2,634	1,794	212
PJM	1,725	—	—
NY/NE	817	—	—
MISO	720	—	—
Asset Closure	50	964	238
Corporate and Other (b)	208	—	—
Eliminations	(2,607)	(1,386)	(171)
Consolidated operating revenues	$ 9,144	$ 5,430	$ 1,191
Depreciation and amortization			
Retail	$ (318)	$ (430)	$ (153)
ERCOT	(416)	(229)	(53)
PJM	(413)	—	—
NY/NE	(152)	—	—
MISO	(9)	—	—
Asset Closure	—	(1)	—
Corporate and Other (b)	(86)	(40)	(11)
Eliminations		1	$ 1
Consolidated depreciation and amortization	$ (1,394)	$ (699)	$ (216)
Operating income (loss)			
Retail	$ 690	$ 461	$ 111
ERCOT	(70)	(118)	(271)
PJM	100	—	—
NY/NE	70	—	—
MISO	36	—	—
Asset Closure	(50)	(68)	16
Corporate and Other (b)	(281)	(78)	(17)
Eliminations	(4)	1	—
Consolidated operating income (loss)	$ 491	$ 198	$ (161)
Interest expense and related charges			
Retail	$ (7)	$ —	$ —
ERCOT	(12)	(21)	1
PJM	(8)	—	—
NY/NE	(2)	—	—
MISO	(1)	—	—
Corporate and Other (b)	(613)	(252)	(66)
Eliminations	71	80	5
Consolidated interest expense and related charges	$ (572)	$ (193)	$ (60)

	Successor		
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016
Income tax (expense) benefit (all Corporate and Other)	$ 45	$ (504)	$ 70
Net income (loss)			
Retail	$ 712	$ 495	$ 114
ERCOT	(55)	(114)	(268)
PJM	100	—	—
NY/NE	79	—	—
MISO	35	—	—
Asset Closure	(49)	(63)	17
Corporate and Other (b)	(876)	(573)	(26)
Eliminations	(2)	1	—
Consolidated net income (loss)	$ (56)	$ (254)	$ (163)
Capital expenditures, excluding LTSA			
Retail	$ 1	$ —	$ 5
ERCOT	283	150	84
PJM	41	—	—
NY/NE	10	—	—
MISO	3	—	—
Corporate and Other (b)	58	26	—
Consolidated capital expenditures	$ 396	$ 176	$ 89

(a) The following unrealized net gains (losses) from mark-to-market valuations of commodity positions are included in operating revenues:

	Successor		
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016
Retail	$ (12)	$ 18	$ (6)
ERCOT	(483)	(305)	(295)
PJM	(50)	—	—
NY/NE	(40)	—	—
MISO	3	—	—
Corporate and Other (b)	(15)	—	—
Eliminations (1)	217	154	113
Consolidated unrealized net losses from mark-to-market valuations of commodity positions included in operating revenues	$ (380)	$ (133)	$ (188)

(1) Amounts offset in fuel, purchased power costs and delivery fees in the Retail segment, with no impact to consolidated results.

(b) Other includes CAISO operations. Income tax expense is not reflected in net income of the segments but is reflected entirely in Corporate net income.

	December 31,	
	2018	2017
Total assets		
Retail	$ 7,699	$ 6,156
ERCOT	9,347	6,821
PJM	7,188	—
NY/NE	2,722	—
MISO	836	—
Asset Closure	254	248
Corporate and Other and Eliminations	(2,022)	1,375
Consolidated total assets	$ 26,024	$ 14,600

Prior to the Effective Date, our Predecessor's chief operating decision maker reviewed the retail electricity, wholesale generation and commodity risk management activities together. Consequently, there were no reportable business segments for TCEH.

23. SUPPLEMENTARY FINANCIAL INFORMATION

Other Income and Deductions

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Other income:				
Office space sublease rental income (a)	$ 8	$ 11	$ 2	$ —
Mineral rights royalty income (b)	—	3	1	3
Sale of land (b)	3	4	—	—
Curtailment gain on employee benefit plans (a)	—	—	4	—
Insurance settlement	16	—	—	9
Interest income	18	15	1	3
All other	2	4	2	4
Total other income	$ 47	$ 37	$ 10	$ 19
Other deductions:				
Write-off of generation equipment (b)	—	2	—	45
Adjustment to asbestos liability	—	—	—	11
All other	5	3	—	19
Total other deductions	$ 5	$ 5	$ —	$ 75

(a) Reported in Corporate and Other non-segment (Successor period only).
(b) Reported in ERCOT segment (Successor period only).

Restricted Cash

	December 31, 2018		December 31, 2017	
	Current Assets	Noncurrent Assets	Current Assets	Noncurrent Assets
Amounts related to the Vistra Operations Credit Facilities (Note 14)	$ —	$ —	$ —	$ 500
Amounts related to restructuring escrow accounts	57	—	59	—
Total restricted cash	$ 57	$ —	$ 59	$ 500

Trade Accounts Receivable

	December 31, 2018	December 31, 2017
Wholesale and retail trade accounts receivable	$ 1,106	$ 596
Allowance for uncollectible accounts	(19)	(14)
Trade accounts receivable — net	$ 1,087	$ 582

Gross trade accounts receivable at December 31, 2018 and 2017 included unbilled retail revenues of $350 million and $251 million, respectively.

Allowance for Uncollectible Accounts Receivable

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
Allowance for uncollectible accounts receivable at beginning of period	$ 14	$ 10	$ —	$ 9
Increase for bad debt expense	56	43	10	20
Decrease for account write-offs	(51)	(39)	—	(16)
Allowance for uncollectible accounts receivable at end of period	$ 19	$ 14	$ 10	$ 13

Inventories by Major Category

	December 31, 2018	December 31, 2017
Materials and supplies	$ 286	$ 149
Fuel stock	115	83
Natural gas in storage	11	21
Total inventories	$ 412	$ 253

Other Investments

	December 31, 2018	December 31, 2017
Nuclear plant decommissioning trust	$ 1,170	$ 1,188
Assets related to employee benefit plans (Note 19)	31	—
Land	49	49
Miscellaneous other	—	3
Total other investments	$ 1,250	$ 1,240

Investment in Unconsolidated Subsidiaries

On the Merger Date, we assumed Dynegy's 50% interest in Northeast Energy, LP (NELP), a joint venture with NextEra Energy, Inc., which indirectly owns the Bellingham NEA facility and the Sayreville facility. At December 31, 2018, our estimated investment in NELP totaled $129 million based on our preliminary purchase price allocation and subsequent 2018 activity. Our risk of loss related to our equity method investment is limited to our investment balance (see Note 2).

For the year ended December 31, 2018, equity earnings related to our investment in NELP totaled $17 million, recorded in equity in earnings (loss) of unconsolidated investment in our statements of consolidated net income (loss). For the year ended December 31, 2018, we received distributions totaling $17 million.

Nuclear Decommissioning Trust

Investments in a trust that will be used to fund the costs to decommission the Comanche Peak nuclear generation plant are carried at fair value. Decommissioning costs are being recovered from Oncor Electric Delivery Company LLC's (Oncor) customers as a delivery fee surcharge over the life of the plant and deposited by Vistra Energy (and prior to the Effective Date, a subsidiary of TCEH) in the trust fund. Income and expense associated with the trust fund and the decommissioning liability are offset by a corresponding change in a regulatory asset/liability (currently a regulatory asset reported in other noncurrent assets) that will ultimately be settled through changes in Oncor's delivery fees rates. If funds recovered from Oncor's customers held in the trust fund are determined to be inadequate to decommission the Comanche Peak nuclear generation plant, Oncor would be required to collect all additional amounts from its customers, with no obligation from Vistra Energy, provided that Vistra Energy complied with PUCT rules and regulations regarding decommissioning trusts. A summary of investments in the fund follows:

	December 31, 2018			
	Cost (a)	Unrealized gain	Unrealized loss	Fair market value
Debt securities (b)	$ 444	$ 7	$ (8)	$ 443
Equity securities (c)	280	448	(1)	727
Total	$ 724	$ 455	$ (9)	$ 1,170

	December 31, 2017			
	Cost (a)	Unrealized gain	Unrealized loss	Fair market value
Debt securities (b)	$ 418	$ 14	$ (2)	$ 430
Equity securities (c)	265	495	(2)	758
Total	$ 683	$ 509	$ (4)	$ 1,188

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(a) Includes realized gains and losses on securities sold.
(b) The investment objective for debt securities is to invest in a diversified tax efficient portfolio with an overall portfolio rating of AA or above as graded by S&P or Aa2 by Moody's Investors Services, Inc. The debt securities are heavily weighted with government and municipal bonds and investment grade corporate bonds. The debt securities had an average coupon rate of 3.69% and 3.55% at December 31, 2018 and 2017, respectively, and an average maturity of 8 years and 9 years at December 31, 2018 and 2017, respectively.
(c) The investment objective for equity securities is to invest tax efficiently and to match the performance of the S&P 500 Index for U.S. equity investments and the MSCI Inc. EAFE Index for non-U.S. equity investments.

Debt securities held at December 31, 2018 mature as follows: $153 million in one to 5 years, $100 million in five to 10 years and $190 million after 10 years.

The following table summarizes proceeds from sales of available-for-sale securities and the related realized gains and losses from such sales.

	Successor			Predecessor
	Year Ended December 31,		Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
	2018	2017		
Realized gains	$ 2	$ 9	$ 1	$ 3
Realized losses	$ (9)	$ (11)	$ —	$ (2)
Proceeds from sales of securities	$ 252	$ 252	$ 25	$ 201
Investments in securities	$ (274)	$ (272)	$ (30)	$ (215)

Property, Plant and Equipment

	December 31,	
	2018	2017
Power generation and structures	$ 14,604	$ 3,966
Land	642	540
Office and other equipment	182	120
Total	15,428	4,626
Less accumulated depreciation	(1,284)	(282)
Net of accumulated depreciation	14,144	4,344
Nuclear fuel (net of accumulated amortization of $189 million and $111 million)	191	158
Construction work in progress	277	318
Property, plant and equipment — net	$ 14,612	$ 4,820

Depreciation expense totaled $1.024 billion, $236 million, $54 million and $401 million for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively.

Our property, plant and equipment consist of our power generation assets, related mining assets, information system hardware, capitalized corporate office lease space and other leasehold improvements. At December 31, 2018, buildings and improvements includes a capital lease for an office building that totaled $62 million with accumulated depreciation of $11 million. The estimated remaining useful lives range from 1 to 35 years for our property, plant and equipment.

Asset Retirement and Mining Reclamation Obligations (ARO)

These liabilities primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, removal of coal/lignite-fueled plant ash treatment facilities and generation plant asbestos removal and disposal costs. There is no earnings impact with respect to changes in the nuclear plant decommissioning liability, as all costs are recoverable through the regulatory process as part of delivery fees charged by Oncor.

At December 31, 2018, the carrying value of our ARO related to our nuclear generation plant decommissioning totaled $1.276 billion, which exceeds the fair value of the assets contained in the nuclear decommissioning trust. Since the costs to ultimately decommission that plant are recoverable through the regulatory rate making process as part of Oncor's delivery fees, a corresponding regulatory asset has been recorded to our consolidated balance sheet of $106 million in other noncurrent assets.

The following table summarizes the changes to these obligations, reported as asset retirement obligations (current and noncurrent liabilities) in our consolidated balance sheets, for the Successor period for the years ended December 31, 2018 and 2017:

	Nuclear Plant Decommissioning	Mining Land Reclamation	Coal Ash and Other	Total
Successor:				
Liability at December 31, 2016	1,200	375	151	1,726
Additions:				
Accretion	33	18	8	59
Adjustment for change in estimates (a)	—	81	44	125
Incremental reclamation costs (b)	—	—	62	62
Reductions:				
Payments	—	(36)	—	(36)
Liability at December 31, 2017	1,233	438	265	1,936
Additions:				
Accretion	43	22	28	93
Adjustment for change in estimates	—	56	(89)	(33)
Obligations assumed in the Merger	—	2	475	477
Reductions:				
Payments	—	(76)	(24)	(100)
Liability at December 31, 2018	1,276	442	655	2,373
Less amounts due currently	—	(106)	(50)	(156)
Noncurrent liability at December 31, 2018	$ 1,276	$ 336	$ 605	$ 2,217

(a) Amounts primarily relate to the impacts of accelerating the ARO associated with the retirements of the Sandow 4, Sandow 5, Big Brown and Monticello plants (see Note 4).
(b) Amounts primarily relate to liabilities incurred as part of acquiring certain real property through the Alcoa contract settlement (see Note 4).

Other Noncurrent Liabilities and Deferred Credits

The balance of other noncurrent liabilities and deferred credits consists of the following:

	December 31, 2018	December 31, 2017
Retirement and other employee benefits	$ 270	$ 166
Uncertain tax positions, including accrued interest	4	—
Other	66	54
Total other noncurrent liabilities and deferred credits	$ 340	$ 220

Fair Value of Debt

Long-Term Debt (see Note 14):	Fair Value Hierarchy	December 31, 2018 Carrying Amount	December 31, 2018 Fair Value	December 31, 2017 Carrying Amount	December 31, 2017 Fair Value
Long-term debt under the Vistra Operations Credit Facilities	Level 2	$ 5,820	$ 5,599	$ 4,323	$ 4,334
Vistra Operations Senior Notes	Level 2	987	963	—	—
Vistra Energy Senior Notes	Level 2	3,819	3,765	—	—
7.000% Amortizing Notes	Level 2	23	24	—	—
Forward Capacity Agreements	Level 3	221	221	—	—
Equipment Financing Agreements	Level 3	102	102	—	—
Mandatorily redeemable subsidiary preferred stock	Level 2	70	70	70	70
Building Financing	Level 2	23	21	30	27

We determine fair value in accordance with accounting standards as discussed in Note 17. We obtain security pricing from an independent party who uses broker quotes and third-party pricing services to determine fair values. Where relevant, these prices are validated through subscription services, such as Bloomberg.

Supplemental Cash Flow Information

The following table reconciles cash, cash equivalents and restricted cash reported in our statements of consolidated cash flows to the amounts reported in our balance sheets at December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017
Cash and cash equivalents	$ 636	$ 1,487
Restricted cash included in current assets	57	59
Restricted cash included in noncurrent assets	—	500
Total cash, cash equivalents and restricted cash	$ 693	$ 2,046

The following table summarizes our supplemental cash flow information for the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 3, 2016 through December 31, 2016	Period from January 1, 2016 through October 2, 2016
Cash payments related to:				
Interest paid (a)	$ 651	$ 245	$ 19	$ 1,064
Capitalized interest	(12)	(7)	(3)	(9)
Interest paid (net of capitalized interest) (a)	$ 639	$ 238	$ 16	$ 1,055
Income taxes	$ 67	$ 63	$ (2)	$ 22
Reorganization items (b)	$ —	$ —	$ —	$ 104
Noncash investing and financing activities:				
Construction expenditures (c)	$ 79	$ 12	$ 1	$ 53
Vistra Energy common stock issued in the Merger (Notes 2 and 16)	$ 2,245	$ —	$ —	$ —

(a) Predecessor period includes amounts paid for adequate protection.
(b) Represents cash payments made by our Predecessor for legal and other consulting services, including amounts paid on behalf of third parties pursuant to contractual obligations approved by the Bankruptcy Court.
(c) Represents end-of-period accruals for ongoing construction projects.

Quarterly Information (Unaudited)

Unaudited results of operations by quarter are summarized below. In our opinion, all adjustments (consisting of normal recurring accruals) necessary for a fair statement of such amounts have been made. Quarterly results are not necessarily indicative of a full year's operations because of seasonal and other factors. Quarterly amounts may not add to full year amounts due to rounding.

	Successor			
	Quarter Ended			
	March 31	June 30	September 30	December 31 (b)
2018(a):				
Operating revenues	$ 765	$ 2,574	$ 3,243	$ 2,562
Operating income (loss)	$ (394)	$ 231	$ 650	$ 4
Net income (loss)	$ (306)	$ 105	$ 331	$ (186)
Net income (loss) attributable to Vistra Energy	$ (306)	$ 108	$ 330	$ (186)
Net income (loss) per weighted average share of common stock outstanding — basic	$ (0.71)	$ 0.21	$ 0.62	$ (0.35)
Net income (loss) per weighted average share of common stock outstanding — diluted	$ (0.71)	$ 0.20	$ 0.61	$ (0.35)
2017:				
Operating revenues	$ 1,357	$ 1,296	$ 1,833	$ 944
Operating income (loss)	$ 155	$ 53	$ 452	$ (462)
Net income (loss)	$ 78	$ (26)	$ 273	$ (579)
Net income (loss) attributable to Vistra Energy	$ 78	$ (26)	$ 273	$ (579)
Net income (loss) per weighted average share of common stock outstanding — basic	$ 0.18	$ (0.06)	$ 0.64	$ (1.35)
Net income (loss) per weighted average share of common stock outstanding — diluted	$ 0.18	$ (0.06)	$ 0.64	$ (1.35)

(a) For the year ended December 31, 2018, reflects the results of operations acquired in the Merger.

(b) For the Successor quarter ended December 31, 2017, operating loss includes noncash charges of $183 million related to the generation facilities retirement announcements. Net loss reflects the retirements mentioned above as well as a $451 million reduction of deferred tax assets related to the decrease in the corporate tax rate due to the TCJA (see Note 9), partially offset by $117 million of impacts of the TRA.

24. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our senior notes are guaranteed by substantially all of our wholly owned subsidiaries. The following condensed consolidating financial statements present the financial information of (i) Vistra Energy Corp. (Parent), which is the ultimate parent company and issuer of the senior notes with effect as of the Merger Date, on a stand-alone, unconsolidated basis, (ii) the guarantor subsidiaries of Vistra Energy (Guarantor Subsidiaries), (iii) the non-guarantor subsidiaries of Vistra Energy (Non-Guarantor Subsidiaries) and (iv) the eliminations necessary to arrive at the information for Vistra Energy on a consolidated basis. The Guarantor Subsidiaries consist of the wholly owned subsidiaries, which jointly, severally, fully and unconditionally, guarantee the payment obligations under the senior notes. See Note 14 for discussion of the senior notes.

These statements should be read in conjunction with the consolidated financial statements and notes thereto of Vistra Energy. The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements. The inclusion of Vistra Energy's subsidiaries as either Guarantor Subsidiaries or Non-Guarantor Subsidiaries in the condensed consolidating financial information is determined as of the most recent balance sheet date presented.

The Parent files a consolidated U.S. federal income tax return. All consolidated income tax expense or benefits and deferred tax assets and liabilities have been allocated to the respective subsidiary columns in accordance with the accounting rules that apply to separate financial statements of subsidiaries. In prior years, the Company had presented condensed financial information of the Parent in Schedule I under Item 15; for purposes of that schedule, consolidated income tax expense or benefits was reflected at the Parent.

Vistra Energy Corp. (Parent) received $4.668 billion, $1.505 billion and $1.0 billion in dividends from its consolidated subsidiaries in the Successor period for the years ended December 31, 2018 and 2017 and the period from October 3, 2016 through December 31, 2016, respectively.

Condensed Statements of Consolidating Income (Loss)
for the Year Ended December 31, 2018
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues	$ —	$ 9,043	$ 174	$ (73)	$ 9,144
Fuel, purchased power costs and delivery fees	—	(4,968)	(92)	24	(5,036)
Operating costs	—	(1,255)	(42)	—	(1,297)
Depreciation and amortization	—	(1,337)	(57)	—	(1,394)
Selling, general and administrative expenses	(266)	(660)	(49)	49	(926)
Operating income (loss)	(266)	823	(66)	—	491
Other income	9	41	—	(3)	47
Other deductions	—	(6)	1	—	(5)
Interest expense and related charges	(257)	(309)	(9)	3	(572)
Impacts of Tax Receivable Agreement	(79)	—	—	—	(79)
Equity in earnings of unconsolidated investment	—	17	—	—	17
Income (loss) before income taxes	(593)	566	(74)	—	(101)
Income tax expense	282	(284)	47	—	45
Equity in earnings (loss) of subsidiaries, net of tax	257	(25)	—	(232)	—
Net income (loss)	(54)	257	(27)	(232)	(56)
Net loss attributable to noncontrolling interest	—	—	2	—	2
Net income (loss) attributable to Vistra Energy	$ (54)	$ 257	$ (25)	$ (232)	$ (54)

Condensed Statements of Consolidating Income (Loss)
for the Year Ended December 31, 2017
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues	$ —	$ 5,430	$ —	$ —	$ 5,430
Fuel, purchased power costs and delivery fees	—	(2,935)	—	—	(2,935)
Operating costs	—	(973)	—	—	(973)
Depreciation and amortization	—	(699)	—	—	(699)
Selling, general and administrative expenses	(47)	(553)	—	—	(600)
Impairment of long-lived assets	—	(25)	—	—	(25)
Operating income (loss)	(47)	245	—	—	198
Other income	—	37	—	—	37
Other deductions	—	(5)	—	—	(5)
Interest Income	4	(4)	—	—	—
Interest expense and related charges	—	(193)	—	—	(193)
Impacts of Tax Receivable Agreement	213	—	—	—	213
Income before income taxes	170	80	—	—	250
Income tax benefit (expense)	80	(584)	—	—	(504)
Equity in earnings (losses) of subsidiaries, net of tax	(504)	—	—	504	—
Net income (loss)	$ (254)	$ (504)	$ —	$ 504	$ (254)

Condensed Statements of Consolidating Income (Loss)
for the Period from October 3, 2016 through December 31, 2016
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues	$ —	$ 1,191	$ —	$ —	$ 1,191
Fuel, purchased power costs and delivery fees	—	(720)	—	—	(720)
Operating costs	—	(208)	—	—	(208)
Depreciation and amortization	—	(216)	—	—	(216)
Selling, general and administrative expenses	(7)	(201)	—	—	(208)
Operating income (loss)	(7)	(154)	—	—	(161)
Other income	—	10	—	—	10
Interest expense and related charges	—	(60)	—	—	(60)
Impacts of Tax Receivable Agreement	(22)	—	—	—	(22)
Income (loss) before income taxes	(29)	(204)	—	—	(233)
Income tax expense	(204)	274	—	—	70
Equity in earnings (loss) of subsidiaries, net of tax	70	—	—	(70)	—
Net income (loss)	(163)	70	—	(70)	(163)

Condensed Statements of Consolidating Comprehensive Income (Loss)
for the Year Ended December 31, 2018
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$ (54)	$ 257	$ (27)	$ (232)	$ (56)
Other comprehensive income (loss), net of tax effects:					
Effect related to pension and other retirement benefit obligations	—	(6)	—	—	(6)
Adoption of accounting standard	1	—	—	—	1
Total other comprehensive income	1	(6)	—	—	(5)
Comprehensive income (loss)	(53)	251	(27)	(232)	(61)
Comprehensive loss attributable to noncontrolling interest	—	—	2	—	2
Comprehensive income (loss) attributable to Vistra Energy	$ (53)	$ 251	$ (25)	$ (232)	$ (59)

Condensed Statements of Consolidating Comprehensive Income (Loss)
for the Year Ended December 31, 2017
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$ (254)	$ (504)	$ —	$ 504	$ (254)
Other comprehensive income (loss), net of tax effects:					
Effect related to pension and other retirement benefit obligations	(23)	(29)	—	29	(23)
Total other comprehensive income	(23)	(29)	—	29	(23)
Comprehensive income (loss)	$ (277)	$ (533)	$ —	$ 533	$ (277)

Condensed Statements of Consolidating Comprehensive Income (Loss)
for the Period from October 3, 2016 through December 31, 2016
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$ (163)	$ 70	$ —	$ (70)	$ (163)
Other comprehensive income (loss), net of tax effects:					
Effect related to pension and other retirement benefit obligations	6	6	—	(6)	6
Total other comprehensive income	6	6	—	(6)	6
Comprehensive income (loss)	(157)	76	—	(76)	(157)

Condensed Statements of Consolidating Cash Flows
for the Year Ended December 31, 2018
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows — operating activities:					
Cash provided by (used in) operating activities	$ (125)	$ 1,917	$ (321)	$ —	$ 1,471
Cash flows — financing activities:					
Issuances of long-term debt	—	1,000	—	—	1,000
Repayments/repurchases of debt	(4,543)	1,468	—	—	(3,075)
Borrowings under accounts receivable securitization program	—	—	339		339
Cash dividend paid	—	(4,668)	—	4,668	—
Stock repurchase	(763)	—	—	—	(763)
Debt tender offer and other financing fees	(179)	(57)	—	—	(236)
Other, net	12	—	—	—	12
Cash provided by (used in) financing activities	(5,473)	(2,257)	339	4,668	(2,723)
Cash flows — investing activities:					
Capital expenditures	(24)	(351)	(3)	—	(378)
Nuclear fuel purchases	—	(118)	—	—	(118)
Cash acquired in the Merger	—	445	—	—	445
Development and growth expenditures	—	(31)	(3)	—	(34)
Proceeds from sales of nuclear decommissioning trust fund securities	—	252	—	—	252
Investments in nuclear decommissioning trust fund securities	—	(274)	—	—	(274)
Dividend received from subsidiaries	4,668			(4,668)	—
Other, net	(1)	7	—	—	6
Cash provided by (used in) investing activities	4,643	(70)	(6)	(4,668)	(101)
Net change in cash, cash equivalents and restricted cash	(955)	(410)	12	—	(1,353)
Cash, cash equivalents and restricted cash — beginning balance	1,183	863	—	—	2,046
Cash, cash equivalents and restricted cash — ending balance	$ 228	$ 453	$ 12	$ —	$ 693

Condensed Statements of Consolidating Cash Flows
for the Year Ended December 31, 2017
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows — operating activities:					
Cash provided by (used in) operating activities	$ (108)	$ 1,494	$ —	$ —	$ 1,386
Cash flows — financing activities:					
Repayments/repurchases of debt	—	(191)	—	—	(191)
Cash dividend paid	—	(1,505)	—	1,505	—
Debt financing fees	—	(8)	—	—	(8)
Other, net	—	(2)	—	—	(2)
Cash provided by (used in) financing activities	—	(1,706)	—	1,505	(201)
Cash flows — investing activities:					
Capital expenditures	—	(114)	—	—	(114)
Nuclear fuel purchases	—	(62)	—	—	(62)
Development and growth expenditures	—	(190)	—	—	(190)
Odessa acquisition	(330)	(25)	—	—	(355)
Proceeds from sales of nuclear decommissioning trust fund securities	—	252	—	—	252
Investments in nuclear decommissioning trust fund securities	—	(272)	—	—	(272)
Dividend received from subsidiaries	1,505			(1,505)	—
Other, net	—	14	—	—	14
Cash provided by (used in) investing activities	1,175	(397)	—	(1,505)	(727)
Net change in cash, cash equivalents and restricted cash	1,067	(609)	—	—	458
Cash, cash equivalents and restricted cash — beginning balance	116	1,472	—	—	1,588
Cash, cash equivalents and restricted cash — ending balance	$ 1,183	$ 863	$ —	$ —	$ 2,046

Condensed Statements of Consolidating Cash Flows
for the Period from October 3, 2016 through December 31, 2016
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows — operating activities:					
Cash provided by (used in) operating activities	$ (36)	$ 117	$ —	$ —	$ 81
Cash flows — financing activities:					
Issuances of long-term debt	—	1,000	—	—	1,000
Cash dividend paid	—	(997)	—	997	—
Special dividends	(992)	—	—	—	(992)
Other, net	1	(3)	—	—	(2)
Cash provided by (used in) financing activities	(991)	—	—	997	6
Cash flows — investing activities:					
Capital expenditures	—	(48)	—	—	(48)
Nuclear fuel purchases	—	(41)	—	—	(41)
Proceeds from sales of nuclear decommissioning trust fund securities	—	25	—	—	25
Investments in nuclear decommissioning trust fund securities	—	(30)	—	—	(30)
Dividend received from subsidiaries	997	—	—	(997)	—
Other, net	—	1	—	—	1
Cash provided by (used in) investing activities	997	(93)	—	(997)	(93)
Net change in cash, cash equivalents and restricted cash	(30)	24	—	—	(6)
Cash, cash equivalents and restricted cash — beginning balance	146	1,448	—	—	1,594
Cash, cash equivalents and restricted cash — ending balance	$ 116	$ 1,472	$ —	$ —	$ 1,588

Condensed Consolidating Balance Sheet as of December 31, 2018
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 171	$ 453	$ 12	$ —	$ 636
Restricted cash	57	—	—	—	57
Advances to affiliates	11	11	—	(22)	—
Trade accounts receivable — net	4	729	464	(110)	1,087
Accounts receivable — affiliates	—	245	—	(245)	—
Notes due from affiliates	—	101	—	(101)	—
Income taxes receivable	—	1	—	(1)	—
Inventories	—	391	21	—	412
Commodity and other derivative contractual assets	—	730	—	—	730
Margin deposits related to commodity contracts	—	361	—	—	361
Prepaid expense and other current assets	2	134	16	—	152
Total current assets	245	3,156	513	(479)	3,435
Investments	—	1,218	32	—	1,250
Investment in unconsolidated subsidiary	—	131	—	—	131
Investment in affiliated companies	11,186	263	—	(11,449)	—
Property, plant and equipment — net	15	14,017	580	—	14,612
Goodwill	—	2,068	—	—	2,068
Identifiable intangible assets — net	10	2,480	3	—	2,493
Commodity and other derivative contractual assets	—	109	—	—	109
Accumulated deferred income taxes	809	599	—	(72)	1,336
Other noncurrent assets	255	330	5	—	590
Total assets	$ 12,520	$ 24,371	$ 1,133	$ (12,000)	$ 26,024
LIABILITIES AND EQUITY					
Current liabilities:					
Accounts receivable securitization program	$ —	$ —	$ 339	$ —	$ 339
Advances from affiliates	—	—	22	(22)	—
Long-term debt due currently	23	163	5	—	191
Trade accounts payable	2	928	121	(106)	945
Accounts payable — affiliates	236	—	9	(245)	—
Notes due to affiliates	—	—	101	(101)	—
Commodity and other derivative contractual liabilities	—	1,376	—	—	1,376
Margin deposits related to commodity contracts	—	4	—	—	4
Accrued taxes	11	—	—	(1)	10
Accrued taxes other than income	—	181	1	—	182
Accrued interest	48	29	4	(4)	77
Asset retirement obligations	—	156	—	—	156
Other current liabilities	74	267	4	—	345
Total current liabilities	394	3,104	606	(479)	3,625

Condensed Consolidating Balance Sheet as of December 31, 2018
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Long-term debt, less amounts due currently	3,819	7,027	28	—	10,874
Commodity and other derivative contractual liabilities	—	270	—	—	270
Accumulated deferred income taxes	—	—	82	(72)	10
Tax Receivable Agreement obligation	420	—	—	—	420
Asset retirement obligations	—	2,203	14	—	2,217
Identifiable intangible liabilities — net	—	278	123	—	401
Other noncurrent liabilities and deferred credits	20	303	17	—	340
Total liabilities	4,653	13,185	870	(551)	18,157
Total stockholders' equity	7,867	11,186	259	(11,449)	7,863
Noncontrolling interest in subsidiary	—	—	4	—	4
Total liabilities and equity	$ 12,520	$ 24,371	$ 1,133	$ (12,000)	$ 26,024

Condensed Consolidating Balance Sheet as of December 31, 2017
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 1,124	$ 363	$ —	$ —	$ 1,487
Restricted cash	59	—	—	—	59
Trade accounts receivable — net	4	578	—	—	582
Inventories	—	253	—	—	253
Commodity and other derivative contractual assets	—	190	—	—	190
Margin deposits related to commodity contracts	—	30	—	—	30
Prepaid expense and other current assets	—	72	—	—	72
Total current assets	1,187	1,486	—	—	2,673
Restricted cash	—	500	—	—	500
Investments	—	1,240	—	—	1,240
Investment in affiliated companies	5,632	—	—	(5,632)	—
Property, plant and equipment — net	—	4,820	—	—	4,820
Goodwill	—	1,907	—	—	1,907
Identifiable intangible assets — net	—	2,530	—	—	2,530
Commodity and other derivative contractual assets	—	58	—	—	58
Accumulated deferred income taxes	5	705	—	—	710
Other noncurrent assets	6	156	—	—	162
Total assets	$ 6,830	$ 13,402	$ —	$ (5,632)	$ 14,600
LIABILITIES AND EQUITY					
Current liabilities:					
Long-term debt due currently	—	44	—	—	44
Trade accounts payable	11	462	—	—	473
Commodity and other derivative contractual liabilities	—	224	—	—	224
Margin deposits related to commodity contracts	—	4	—	—	4
Accrued taxes	58	—	—	—	58
Accrued taxes other than income	—	136	—	—	136
Accrued interest	—	16	—	—	16
Asset retirement obligations	—	99	—	—	99
Other current liabilities	86	211	—	—	297
Total current liabilities	155	1,196	—	—	1,351
Long-term debt, less amounts due currently	—	4,379	—	—	4,379
Commodity and other derivative contractual liabilities	—	102	—	—	102
Tax Receivable Agreement obligation	333	—	—	—	333
Asset retirement obligations	—	1,837	—	—	1,837
Identifiable intangible liabilities — net	—	36	—	—	36
Other noncurrent liabilities and deferred credits	—	220	—	—	220
Total liabilities	488	7,770	—	—	8,258
Total equity	6,342	5,632	—	(5,632)	6,342
Total liabilities and equity	$ 6,830	$ 13,402	$ —	$ (5,632)	$ 14,600

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

An evaluation was performed under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, of the effectiveness of the design and operation of the disclosure controls and procedures in effect at December 31, 2018. Based on the evaluation performed, our management, including the principal executive officer and principal financial officer, concluded that the disclosure controls and procedures were effective.

Other than the changes resulting from the Merger, there have been no change in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

VISTRA ENERGY CORP.
MANAGEMENT'S ANNUAL REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Vistra Energy Corp. is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) for the company. Vistra Energy Corp.'s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in condition or the deterioration of compliance with procedures or policies.

The management of Vistra Energy Corp. performed an evaluation as of December 31, 2018 of the effectiveness of the company's internal control over financial reporting based on the Committee of Sponsoring Organizations of the Treadway Commission's (COSO's) *Internal Control - Integrated Framework (2013)*. Based on the review performed, management believes that as of December 31, 2018 Vistra Energy Corp.'s internal control over financial reporting was effective.

The independent registered public accounting firm of Deloitte & Touche LLP as auditors of the consolidated financial statements of Vistra Energy Corp. has issued an attestation report on Vistra Energy Corp.'s internal control over financial reporting.

/s/ Curtis A. Morgan	/s/ J. William Holden
Curtis A. Morgan	J. William Holden
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

February 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Vistra Energy Corp.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Vistra Energy Corp. and its subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - *Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2018, of the Company and our report dated February 28, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte & Touche LLP

Dallas, TX
February 28, 2019

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Code of Ethics

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

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

Item 11. EXECUTIVE COMPENSATION

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

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this Item is incorporated by reference to the sections entitled "Beneficial Ownership of Common Stock of the Company" in Vistra Energy's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this Item is incorporated by reference to the sections entitled "Business Relationships and Related Person Transactions Policy" and "Director Independence" in Vistra Energy's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

Item 14. PRINCIPAL ACCOUNTING FEES

Information required by this Item is incorporated by reference to the sections entitled "Principal Accounting Fees" in Vistra Energy's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Our financial statements and financial statement schedules are incorporated under Part II, Item 8 of this Annual Report on Form 10-K.

(b) EXHIBITS:

Vistra Energy Corp. Exhibits to Form 10-K for the Fiscal Year Ended December 31, 2018

Exhibits	Previously Filed With File Number*	As Exhibit		
(2)	**Plan of Acquisition, Reorganization, Arrangement, Liquidation, or Succession**			
2.1	333-215288 Form S-1 (filed December 23, 2016)	2.1	—	Order of the United States Bankruptcy Court for the District of Delaware Confirming the Third Amended Joint Plan of Reorganization
2.2	001-38086 Form 8-K (filed October 31, 2017)	2.1	—	Agreement and Plan of Merger, dated as of October 29, 2017, by and between Vistra Energy Corp. and Dynegy, Inc.
(3(i))	**Articles of Incorporation**			
3.1	333-215288 Form S-1 (filed December 23, 2016)	3.1		Certification of Incorporation of TCEH Corp. (now known as Vistra Energy Corp.), dated October 3, 2016
3.2	333-215288 Form S-1 (filed December 23, 2016)	3.2	—	Certificate of Amendment of Certificate of Incorporation of TCEH Corp. (now known as Vistra Energy Corp.), dated November 2, 2016
(3(ii))	**By-laws**			
3.3	333-215288 Form S-1 (filed December 23, 2016)	3.3	—	Restated Bylaws of Vistra Energy Corp., dated November 4, 2016
(4)	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	001-33443 Form 8-K (filed on October 30, 2014)	4.8	—	2022 Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and the Trustee
4.2	001-33443 Form 8-K (filed on April7, 2015)	4.11	—	First Supplemental Indenture to the 2022 Notes Indenture, dated April 1, 2015, between Dynegy and the Trustee
4.3	001-33443 Form 8-K (filed on April 7, 2015)	4.12	—	Second Supplemental Indenture to the 2022 Notes Indenture, dated April 1, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.4	001-33443 Form 8-K (filed on April 8, 2015)	4.17	—	Third Supplemental Indenture to the 2022 Notes Indenture, dated April 2, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.5	001-33443 Form 10-Q (Quarter ended June 30, 2015) (filed on August 7, 2015)	4.2	—	Fourth Supplemental Indenture to the 2022 Notes Indenture, dated May 11, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.6	001-33443 Form 10-Q (Quarter ended September 30, 2015) (filed on November 5, 2015)	4.2	—	Fifth Supplemental Indenture to the 2022 Notes Indenture, dated September 21, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.7	001-33443 Form 10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.24	—	Sixth Supplemental Indenture to the 2022 Notes Indenture, dated February 2, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.8	001-33443 Form 10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.25	—	Seventh Supplemental Indenture to the 2022 Notes Indenture, dated February 7, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.9	001-38086 Form 8-K (filed on April 9, 2018)	4.19	—	Eighth Supplemental Indenture to the 2022 Notes Indenture, dated April 9, 2018, among the Company, the Subsidiary Guarantors and the Trustee
4.10	001-38086 Form 8-K (filed on June 15, 2018)	4.1	—	Ninth Supplemental Indenture to the 2022 Notes Indenture, dated June 14, 2018, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.11	001-38086 Form 8-K (filed on February 9, 2019)	4.4	—	Tenth Supplemental Indenture to the 2022 Notes Indenture, dated February 6, 2019, by and among the Company and the Trustee.
4.12	001-33443 Form 8-K (filed on October 30, 2014)	4.8	—	Form of 7.375% Senior Note due 2022
4.13	001-33443 Form 8-K (filed on May 21, 2013)	4.1	—	2023 Notes Indenture, dated May 20, 2013, among Dynegy, the Subsidiary Guarantors and the Trustee
4.14	001-33443 Form 10-K (Year ended December 31, 2013) (filed on February 27, 2014)	4.3	—	First Supplemental Indenture to the 2023 Notes Indenture, dated as of December 5, 2014, among Dynegy, the Subsidiary Guarantors and the Trustee
4.15	001-33443 Form 8-K (filed on April 7, 2015)	4.20	—	Second Supplemental Indenture to the 2023 Notes Indenture, dated April 1, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.16	001-33443 Form 8-K (filed on April 8, 2015)	4.28	—	Third Supplemental Indenture to the 2023 Notes Indenture, dated April 2, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.17	001-33443 Form 10-Q (Quarter ended June 30, 2015) (filed on August 7, 2015)	4.4	—	Fourth Supplemental Indenture to the 2023 Notes Indenture, dated May 11, 2015, among Dynegy, the Subsidiary Guarantors
4.18	001-33443 Form 10-Q (Quarter ended September 30, 2015) (filed on November 5, 2015)	4.4	—	Fifth Supplemental Indenture to the 2023 Notes Indenture, dated September 21, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.19	001-33443 Form10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.7	—	Sixth Supplemental Indenture to the 2023 Notes Indenture, dated February 2, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.20	001-33443 Form10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.8	—	Seventh Supplemental Indenture to the 2023 Notes Indenture, dated February 7, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.21	001-38086 Form 8-K (filed on April 9, 2018)	4.29	—	Eighth Supplemental Indenture to the 2023 Notes Indenture, dated April 9, 2018, among the Company, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.22	001-38086 Form 8-K (filed on June 15, 2018)	4.2	—	Ninth Supplemental Indenture to the 2023 Notes Indenture, dated June 14, 2018, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.23	001-33443 Form 8-K (filed on May 21, 2013)	4.1	—	Form of 5.875% Senior Note due 2023
4.24	001-33443 Form 8-K (filed on October 30, 2014)	4.9	—	2024 7.625% Notes Indenture, dated October 27, 2014, among Dynegy Finance II, Inc. and the Trustee
4.25	001-33443 Form 8-K (filed on April 7, 2015)	4.14	—	First Supplemental Indenture to the 2024 7.625% Notes Indenture, dated April 1, 2015, between Dynegy and the Trustee
4.26	001-33443 Form 8-K (filed on April 7, 2015)	4.15	—	Second Supplemental Indenture to the 2024 7.625% Notes Indenture, dated April 1, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.27	001-33443 Form 8-K (filed on April 8, 2015)	4.21	—	Third Supplemental Indenture to the 2024 7.625% Notes Indenture, dated April 2, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.28	001-33443 Form 10-Q (Quarter ended June 30, 2015) (filed on August 7, 2015)	4.3	—	Fourth Supplemental Indenture to the 2024 7.625% Notes Indenture, dated May 11, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.29	001-33443 Form 10-Q (Quarter ended September 30, 2015) (filed on November 5, 2015)	4.3	—	Fifth Supplemental Indenture to the 2024 7.625% Notes Indenture, dated September 21, 2015, among Dynegy, the Subsidiary Guarantors and the Trustee
4.30	001-33443 Form 10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.32	—	Sixth Supplemental Indenture to the 2024 7.625% Notes Indenture, dated February 2, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.31	001-33443 Form 10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.33	—	Seventh Supplemental Indenture to the 2024 7.625% Notes Indenture, dated February 7, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.32	001-38086 Form 8-K (filed on April 9, 2018)	4.39	—	Eighth Supplemental Indenture to the 2024 7.625% Notes Indenture, dated April 9, 2018, among the Company, the Subsidiary Guarantors and the Trustee
4.33	001-38086 Form 8-K (filed on June 15, 2018)	4.3	—	Ninth Supplemental Indenture to the 2024 7.625% Notes Indenture, dated June 14, 2018, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.34	001-33443 Form of 8-K (filed on October 30, 2014)	4.9	—	Form of 7.625% Senior Note due 2024
4.35	001-33443 Form 8-K (filed on October 11, 2016)	4.1	—	2025 Notes Indenture, dated October 11, 2016, between Dynegy and the Trustee
4.36	001-33443 Form 10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.35	—	First Supplemental Indenture to the 2025 Notes Indenture, dated February 2, 2017, between Dynegy, the Subsidiary Guarantors and the Trustee
4.37	001-33443 Form 10-K (Year ended December 31, 2016) (filed on February 24, 2017)	4.36	—	Second Supplemental Indenture to the 2025 Notes Indenture, dated February 7, 2017, between Dynegy, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.38	001-38086 Form 8-K (filed on April 9, 2018)	4.48	—	Third Supplemental Indenture to the 2025 Notes Indenture, dated April 9, 2018, among the Company, the Subsidiary Guarantors and the Trustee
4.39	001-38086 Form 8-K (filed on June 15, 2018)	4.5	—	Fourth Supplemental Indenture to the 2025 Notes Indenture, dated June 14, 2018, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.40	001-38086 Form 8-K (filed on August 23, 2018)	4.6	—	Fifth Supplemental Indenture to the 2025 Notes Indenture, dated August 22, 2018, by and among the Company and Wilmington Trust, National Association, as Trustee
4.41	001-33443 Form 8-K (filed on October 11, 2016)	4.1	—	Form of 8.000% Senior Note due 2025
4.42	001-33443 Form 8-K (filed on August 21, 2017)	4.1	—	2026 Notes Indenture, dated August 21, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.43	001-33443 Form 8-K (filed on August 21, 2017)	4.2	—	Registration Rights Agreement, dated August 21, 2017, among Dynegy, the Subsidiary Guarantors and the Trustee
4.44	001-38086 Form 8-K (filed on April 9, 2018)	4.52	—	First Supplemental Indenture to the 2026 Notes Indenture, dated April 9, 2018, among the Company, the Subsidiary Guarantors and the Trustee
4.45	001-38086 Form 8-K (filed on June 15, 2018)	4.6	—	Second Supplemental Indenture to the 2026 Notes Indenture, dated June 14, 2018, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.46	001-38086 Form 8-K (filed on August 23, 2018)	4.4	—	Third Supplemental Indenture to the 2026 Notes Indenture, dated August 22, 2018, by and among the Company and Wilmington Trust, National Association, as Trustee
4.47	001-33443 Form 8-K (filed on August 21, 2017)	4.1	—	Form of 8.125% Senior Note due 2026
4.48	001-38086 Form 8-K (filed on August 23, 2018)	4.1	—	Indenture for 5.500% Senior Note due 2026, dated as of August 22, 2018, among Vistra Operations Company LLC, as issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.49	001-38086 Form 8-K (filed on August 23, 2018)	4.2	—	Form of Rule 144A Global Security for 5.500% Senior Note due 2026 (included in Exhibit 4.1)
4.50	001-38086 Form 8-K (filed on August 23, 2018)	4.3	—	Form of Regulation S Global Security for 5.500% Senior Note due 2026 (included in Exhibit 4.1)
4.51	001-38086 Form 8-K (filed on February 6, 2019)	4.1	—	Indenture for 5.675% Senior Note due 2027, dated as of February 6, 2019, among Vistra Operations Company LLC, as issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.52	001-38086 Form 8-K (filed on February 6, 2019)	4.2	—	Form of Rule 144A Global Security for 5.675% Senior Note due2027 (included in Exhibit 4.1)
4.53	001-38086 Form 8-K (filed on February 6, 2019)	4.3	—	Form of Regulation S Global Security for 5.675% Senior Note due 2027 (included in Exhibit 4.1)

Exhibits	Previously Filed With File Number*	As Exhibit		
4.54	001-38086 Form 8-K (filed on August 23, 2018)	4.7	—	Purchase and Sale Agreement dated as of August 21, 2018, between TXU Energy Retail Company LLC as originator, and TXU Energy Receivables Company LLC, as purchaser
4.55	001-38086 Form 8-K (filed on August 23, 2018)	4.8	—	Receivable Purchase Agreement dated as of August 21, 2018, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.56	001-33443 Form 8-K (filed on June 21, 2016)	4.3	—	Purchase Contract Agreement, dated June 21, 2016, between Dynegy and the Trustee
4.57	001-38086 Registration Statement on Form 8-A (filed on April 9, 2018)	4.5	—	First Supplement to the Purchase Contract Agreement, dated April 9, 2018, between the Company, the Purchase Contract Agent and the Trustee
4.58	001-33443 Form 8-K (filed on June 21, 2016)	4.3	—	Form of Unit
4.59	001-33443 Form 8-K (filed on June 21, 2016)	4.3	—	Form of Purchase Contract
4.60	001-33443 Form 8-K (filed on June 21, 2016)	4.1	—	Amortizing Notes Indenture, dated June 21, 2016, between Dynegy and the Trustee
4.61	001-33443 Form 8-K (filed on June 21, 2016)	4.2	—	First Supplemental Indenture to the Amortizing Notes Indenture, dated June 21, 2016, between Dynegy and the Trustee
4.62	001-38086 Registration Statement on Form 8-A (filed on April 9, 2018)	4.3	—	Second Supplemental Indenture to the Amortizing Notes Indenture, dated April 9, 2018, between the Company and the Trustee
4.63	001-33443 Form 8-K (filed on June 21, 2016)	4.2	—	Form of Amortizing Note
4.64	001-33443 Form of 8-K (filed on February 7, 2017)	4.1	—	Warrant Agreement, dated February 2, 2017, by and among Dynegy, Computershare Inc. and Computershare Trust Company, N.A., as warrant agent
4.65	001-38086 Registration Statement on Form 8-A (filed on April 9, 2018)	4.2	—	Supplemental Warrant Agreement, dated as of April 9, 2018 among the Company and the Warrant Agent
4.66	001-33443 Form of 8-K (filed on February 7, 2017)	4.1	—	Form of Warrant
4.67	333-215288 Form S-1 (filed December 23, 2016)	4.1	—	Registration Rights Agreement, by and among TCEH Corp. (now known as Vistra Energy Corp.) and the Holders party thereto, dated as of October 3, 2016
(10)	**Material Contracts**			
	Management Contracts; Compensatory Plans, Contracts and Arrangements			

Exhibits	Previously Filed With File Number*	As Exhibit		
10.1	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.6	—	2016 Omnibus Incentive Plan
10.2	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.7	—	Form of Option Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.3	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.8	—	Form of Restricted Stock Unit Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.4	001-33443 Form10-K (Year ended December 31, 2017) (filed on February 26, 2018)	10(d)	—	Form of Performance Stock Unit Award Agreement for 2016 Omnibus Incentive Plan
10.5	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.9	—	Vistra Energy Corp. Executive Annual Incentive Plan
10.6	**	—	—	Amended and Restated 2016 Omnibus Incentive Plan, effective as of February 26, 2019
10.7	**	—	—	Vistra Energy Equity Deferred Compensation Plan for Certain Directors
10.8	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.10	—	Stockholder's Agreement, dated as of October 3, 2016, by and between TCEH Corp. (now known as Vistra Energy Corp.) and Apollo Management Holdings, L.P.
10.9	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.11	—	Stockholder's Agreement, dated as of October 3, 2016, by and between TCEH Corp. (now known as Vistra Energy Corp.) and Brookfield Asset Management Private Institutional Capital Adviser (Canada)
10.10	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.12	—	Stockholder's Agreement, dated as of October 3, 2016, by and between TCEH Corp. (now known as Vistra Energy Corp.) and Oaktree Capital Management, L.P. and certain of its affiliated entities
10.11	001-38086 Form 8-K (filed April 27, 2018)	10.1	—	Termination of Stockholder's Agreement, dated as of April 24,2018, by and among the Company and the Oaktree Stockholder
10.12	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.19	—	Employment Agreement between Curtis A. Morgan and Vistra Energy Corp.
10.13	001-38086 Form 8-K (filed May 4, 2018)	10.1	—	Amended and Restated Employment Agreement, dated as of May 1,2018, between Curtis A. Morgan and Vistra Energy Corp.
10.14	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.20	—	Employment Agreement between James A. Burke and Vistra Energy Corp.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.15	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.21	—	Employment Agreement between William Holden and Vistra Energy Corp.
10.16	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.22	—	Employment Agreement between Stephanie Zapata Moore and Vistra Energy Corp.
10.17	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.23	—	Employment Agreement between Carrie Lee Kirby and Vistra Energy Corp.
10.18	**		—	Agreement between Scott A. Hudson, Vistra Energy Corp. and TXU Retail Service Company
10.19	**		—	Agreement between Stephen J. Muscato, Vistra Energy Corp. and Luminant Energy Company LLC
10.20	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.24	—	Employment Agreement between Sara Graziano and Vistra Energy Corp.
10.21	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.26	—	Form of indemnification agreement with directors
10.22	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.29	—	Stock Purchase Agreement, dated as of October 25, 2016, by and between TCEH Corp. (now known as Vistra Energy Corp.) and Curtis A. Morgan
	Credit Agreements and Related Agreements			
10.23	333-215288 Form S-1 (filed December 23, 2016)	10.1	—	Credit Agreement, dated as of October 3, 2017
10.24	333-215288 Form S-1 (filed December 23, 2016)	10.2	—	Amendment to Credit Agreement, dated December 14, 2016, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.25	333-215288 Amendment No. 1 to Form S-1 (filed February 14, 2017)	10.3	—	Second Amendment to Credit Agreement, dated February 1, 2017, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.26	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.4	—	Third Amendment to Credit Agreement, dated February 28, 2017, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.27	001-38086 Form 8-K (filed August 17, 2017)	10.1	—	Fourth Amendment to Credit Agreement, dated as of August 17, 2017 (effective August 17, 2017), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.28	001-38086 Form 8-K (filed December 14, 2017)	10.1	—	Fifth Amendment to Credit Agreement, dated as of December 14, 2017 (effective December 14, 2017), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.29	001-38086 Form 8-K (filed February 22, 2018)	10.1	—	Sixth Amendment to Credit Agreement, dated as of February 20, 2018 (effective February 20, 2018), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.30	001-38086 Form 8-K (filed June 15, 2018)	10.1	—	Seventh Amendment to Credit Agreement, dated as of June 14, 2018, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties party thereto, Credit Suisse and Citibank, N.A. as the 2018 Incremental Term Loan Lenders, the various other Lenders party thereto, Credit Suisse as Successor Administrative Agent and as Successor Collateral Agent, and Delaware Trust Company, as Collateral Trustee.
10.31	001-38086 Form 8-K (filed on August 7, 2018)	10.1	—	Purchase Agreement, dated August 7, 2018, by and among Vistra Operations Company LLC and Citigroup Global Markets Inc., on behalf of itself and the several Initial Purchasers named in Schedule I to the Purchase Agreement
10.32	001-38086 Form 8-K (filed on January 24, 2019)	10.1	—	Purchase Agreement, dated January 22, 2019, by and among Vistra Operations Company LLC and J.P. Morgan Securities LLC. On behalf of itself and the several Initial Purchasers named in Schedule I to the Purchase Agreement
10.33	001-38086 Form 8-K (filed on April 9, 2018)	10.10		Assumption Agreement, dated as of April 9, 2018, between Vistra Energy Corp. (as successor by merger to Dynegy Inc.), and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent and as Collateral Trustee.
10.34	001-38086 Form 8-K (filed on April 9, 2018)	10.11		Guarantee and Collateral Agreement, dated as of April 23, 2013, among Dynegy Inc., the subsidiaries of the borrower from time to time party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013).
10.35	001-38086 Form 8-K (filed on April 9, 2018)	10.12		Joinder, dated as of April 9, 2018, among Vistra Energy Corp., the subsidiary guarantors party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee.
10.36	001-38086 Form 8-K (filed on April 9, 2018)	10.13		Collateral Trust and Intercreditor Agreement, dated as of April 23, 2013 among Dynegy, the Subsidiary Guarantors (as defined therein), Credit Suisse AG, Cayman Islands Branch and each person party thereto from time to time (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013).
	Other Material Contracts			
10.37	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.5	—	Collateral Trust Agreement, dated as of October 3, 2016, by and among TEX Operations Company LLC (now known as Vistra Operations LLC), the Grantors from time to time thereto, Railroad Commission of Texas, as first-out representative, and Deutsche Bank AG, New York Branch, as senior credit agreement representative
10.38	001-38086 Form 8-K (filed on June 15, 2018)	10.2	—	Amendment to Collateral Trust Agreement, effective as of June 14, 2018, among Vistra Operations Company LLC, the other Grantors from time to time party thereto, Railroad Commission of Texas, as first-out representative, and Credit Suisse AG, Cayman Islands Branch, as senior credit agreement agent, and Delaware Trust Company, as Collateral Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
10.39	001-38086 Form 8-K (filed on June 15, 2018)	10.3	—	Collateral Trust Joinder, dated June 14, 2018, between the Additional Grantors party thereto and Delaware Trust Company, as Collateral Trustee, to the Collateral Trust Agreement, effective pursuant to the Seventh Amendment as of June 14, 2018, among Vistra Operations Company LLC, the other Grantors from time to time party thereto, Railroad Commission of Texas, as First-Out Representative, Credit Suisse AG, Cayman Islands Branch, as Senior Credit Agreement Agent, and Delaware Trust Company, as Collateral Trustee.
10.40	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.13	—	Tax Receivable Agreement, by and between TEX Energy LLC (now known as Vistra Energy Corp.) and American Stock Transfer & Trust Company, as transfer agent, dated as of October 3, 2016
10.41	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.14	—	Tax Matters Agreement, by and among TEX Energy LLC (now known as Vistra Energy Corp.), Energy Future Holdings Corp., Energy Future Intermediate Holding Company LLC, EFI Finance Inc. and EFH Merger Co. LLC, dated as of October 3, 2016
10.42	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.15	—	Transition Services Agreement, by and between Energy Future Holdings Corp. and TEX Operations Company LLC (now known as Vistra Operations Company LLC), dated as of October 3, 2016
10.43	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.16	—	Separation Agreement, by and between Energy Future Holdings Corp., TEX Energy LLC (now known as Vistra Energy Corp.) and TEX Operations Company LLC (now known as Vistra Operations LLC), dated as of October 3, 2016
10.44	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.17	—	Purchase and Sale Agreement, dated as of November 25, 2015, by and between La Frontera Ventures, LLC and Luminant Holding Company LLC
10.45	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.18	—	Amended and Restated Split Participant Agreement, by and between Oncor Electric Delivery Company LLC (f/k/a TXU Electric Delivery Company) and TEX Operations Company LLC (now known as Vistra Operations Company LLC), dated as of October 3, 2016
10.46	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.27	—	Lease Agreement, dated February 14, 2002, between State Street Bank and Trust Company of Connecticut, National Association, an owner trustee of ZSF/Dallas Tower Trust, a Delaware grantor trust, as lessor and EFH Properties Company (now known as Vistra EP Properties Company), as Lessee (Energy Plaza Property)
10.47	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.28	—	First Amendment, dated June 1, 2007, to Lease Agreement, dated February 14, 2002
10.48	001-38086 Form 8-K (filed July 7, 2017)	10(a)	—	Asset Purchase Agreement, dated as of July 5, 2017, by and among Odessa-Ector Power Partners, L.P., La Frontera Holdings, LLC, Vistra Operations Company LLC, Koch Resources, LLC
10.49	001-38086 Form 8-K (filed October 31, 2017)	10.1	—	Merger Support Agreement, dated as of October 29, 2017, by and between Vistra Energy Corp. and Terawatt Holdings, LP
10.50	001-38086 Form 8-K (filed October 31, 2017)	10.2	—	Merger Support Agreement, dated as of October 29, 2017, by and among Vistra Energy Corp. and Oaktree Opportunities Fund VIII, L.P., Oaktree Huntington Investment Fund, L.P., Oaktree Opportunities Fund VIII (Parallel 2), L.P., Oaktree Opportunities Fund VIIIb, L.P., Oaktree Opportunities Fund IX, L.P. and Oaktree Opportunities Fund IX (Parallel 2), L.P.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.51	001-38086 Form 8-K (filed on August 23, 2018)	10.1	—	Amendment No. 1 to Registration Rights Agreement dated as of August 22, 2018, by and among the Company and the Guarantors (as defined therein)
(21)	**Subsidiaries of the Registrant**			
21.1	**		—	Significant Subsidiaries of Vistra Energy Corp.
(23)	**Consent of Experts**			
23.1	**		—	Consent of Deloitte & Touche LLP
(31)	**Rule 13a-14(a) / 15d-14(a) Certifications**			
31.1	**		—	Certification of Curtis A. Morgan, principal executive officer of Vistra Energy Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	**		—	Certification of J. William Holden, principal financial officer of Vistra Energy Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32)	**Section 1350 Certifications**			
32.1	**		—	Certification of Curtis A. Morgan, principal executive officer of Vistra Energy Corp., pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	**		—	Certification of J. William Holden, principal financial officer of Vistra Energy Corp., pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(95)	**Mine Safety Disclosures**			
95.1	**		—	Mine Safety Disclosures
	XBRL Data Files			
101.INS	**		—	XBRL Instance Document
101.SCH	**		—	XBRL Taxonomy Extension Schema Document
101.CAL	**		—	XBRL Taxonomy Extension Calculation Document
101.DEF	**		—	XBRL Taxonomy Extension Definition Document
101.LAB	**		—	XBRL Taxonomy Extension Labels Document
101.PRE	**		—	XBRL Taxonomy Extension Presentation Document

* Incorporated herein by reference
** Filed herewith

Item 16. FORM 10-K SUMMARY

Not applicable.

SIGNATURES

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

VISTRA ENERGY CORP.

Date: February 28, 2019

By /s/ CURTIS A. MORGAN

Curtis A. Morgan (President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Vistra Energy Corp. and in the capacities and on the date indicated.

Signature	Title	Date
/s/ CURTIS A. MORGAN (Curtis A. Morgan, President and Chief Executive Officer)	Principal Executive Officer and Director	February 28, 2019
/s/ J. WILLIAM HOLDEN (J. William Holden, Executive Vice President and Chief Financial Officer)	Principal Financial Officer	February 28, 2019
/s/ CHRISTY DOBRY (Christy Dobry, Vice President and Controller)	Principal Accounting Officer	February 28, 2019
/s/ SCOTT B. HELM (Scott B. Helm, Chairman of the Board)	Chairman of the Board and Director	February 28, 2019
/s/ HILARY E. ACKERMANN (Hilary E. Ackermann)	Director	February 28, 2019
/s/ GAVIN R. BAIERA (Gavin R. Baiera)	Director	February 28, 2019
/s/ PAUL M. BARBAS (Paul M. Barbas)	Director	February 28, 2019
/s/ BRIAN K. FERRAIOLI (Brian K. Ferraioli)	Director	February 28, 2019
/s/ JEFF D. HUNTER (Jeff D. Hunter)	Director	February 28, 2019
/s/ CYRUS MADON (Cyrus Madon)	Director	February 28, 2019
/s/ GEOFFREY D. STRONG (Geoffrey D. Strong)	Director	February 28, 2019
/s/ JOHN R. SULT (John R. Sult)	Director	February 28, 2019
/s/ BRUCE ZIMMERMAN (Bruce Zimmerman)	Director	February 28, 2019

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Stockholder Information

Stock Exchange Listing

NYSE: VST

Corporate Headquarters

Vistra Energy Corp.
6555 Sierra Drive
Irving, Texas 75039

Stock Transfer Agent and Registrar

Please direct general questions about stockholder accounts, stock certificates, transfer of shares, or duplicate mailings to Vistra Energy's transfer agent:

American Stock Transfer & Trust Company, LLC
6201 15th Avenue
Brooklyn, NY 11219
Phone: (800) 937-5449
Email: info@amstock.com

Independent Registered Accounting Firm

Deloitte & Touche LLP

Officer Certifications

Our Annual Report on Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Sarbanes-Oxley ACT Section 302 and 906 certifications by the CEO and CFO. We will send stockholders copies of the exhibits to our Annual Report on Form 10-K and any of our corporate governance documents, free of charge, upon request.

Note that these documents, along with further information about our company, board of directors, management team and contact details, are available on our website at www.vistraenergy.com.

Board of Directors †

Hilary E. Ackermann (4)*

Gavin R. Baiera (2)*

Paul M. Barbas (2,3)

Brian K. Ferraioli (1)*

Scott B. Helm, Chairman of the Board of Directors

Jeff D. Hunter (2,4)

Cyrus Madon (3)

Curtis A. Morgan

Geoffrey D. Strong (3)

John R. Sult (1,4)

Bruce E. Zimmerman (1)

[1] Audit Committee
[2] Compensation Committee
[3] Nominating and Governance Committee
[4] Risk Committee
* Committee Chair

† As of March 31, 2019. Besides Curtis A. Morgan, all members of the Vistra Energy Board of Directors satisfy the independence requirements of the Securities and Exchange Commission and the NYSE.

VISTRA
ENERGY

Vistra Energy Corp. | 6555 Sierra Drive, Irving, Texas 75039 | www.vistraenergy.com